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

FORM 10-K

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

For the fiscal year ended December 31, 2017

OR

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

Commission File Number 333-216891

Energy Resources 12, L.P.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**81-4805237** (IRS Employer Identification No.)
120 W 3rd Street, Suite 220 **Fort Worth, Texas** (Address of principal executive offices)	**76102** (Zip Code)

(817) 882-9192
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Exchange Act: None

Securities registered pursuant to Section 12(g) of the Exchange Act: Common Units of Limited Partnership Interest

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☐ No ☑

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☑

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

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

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

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☑
Emerging growth company ☑	

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

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

There is no established public market for the registrant's outstanding limited partnership interests. The aggregate market value of the registrant's limited partnership interests held by non-affiliates of the registrant as of June 30, 2017 was $0.

As of February 22, 2018, the Partnership had 3,600,462 common units outstanding.

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Part I

FORWARD LOOKING STATEMENTS

Certain statements within this report may constitute forward-looking statements. Forward-looking statements are those that do not relate solely to historical fact. They include, but are not limited to, any statement that may predict, forecast, indicate or imply future results, performance, achievements or events. You can identify these statements by the use of words such as “may,” “will,” “could,” “anticipate,” “believe,” “estimate,” “expect,” “intend,” “predict,” “continue,” “further,” “seek,” “plan” or “project” and variations of these words or comparable words or phrases of similar meaning.

These forward-looking statements include such things as:

- investment objectives and the Partnership’s ability to make investments in a timely manner on acceptable terms;
- references to future success in the Partnership’s property acquisition, drilling and marketing activities;
- the Partnership’s use of proceeds of the public offering and its business strategy;
- estimated future capital expenditures;
- estimated future distributions;
- sales of the Partnership’s properties and other liquidity events;
- competitive strengths and goals; and
- other similar matters.

These forward-looking statements reflect the Partnership’s current beliefs and expectations with respect to future events and are based on assumptions and are subject to risks and uncertainties and other factors outside the Partnership’s control that may cause actual results to differ materially from those projected. Such factors include, but are not limited to, those described under “Risk Factors” and the following:

- that the Partnership’s strategy of acquiring oil and gas properties on attractive terms and developing those properties may not be successful or, even if the Partnership successfully acquires properties, that its operations on such properties may not be successful;
- general economic, market, or business conditions;
- changes in laws or regulations;
- the risk that the wells in which the Partnership acquires an interest are productive, but do not produce enough revenue to return the investment made;
- the risk that the wells the Partnership drills do not find hydrocarbons in commercial quantities or, even if commercial quantities are encountered, that actual production is lower than expected on the productive life of wells is shorter than expected;
- current credit market conditions and the Partnership’s ability to obtain long-term financing for its property acquisitions and drilling activities in a timely manner and on terms that are consistent with what the Partnership projects when it invests in a property;
- uncertainties concerning the price of oil and natural gas, which may decrease and remain low for prolonged periods; and
- the risk that any hedging policy the Partnership employs to reduce the effects of changes in the prices of its production will not be effective.

Although the Partnership believes the expectations reflected in such forward-looking statements are based upon reasonable assumptions, the Partnership cannot assure investors that its expectations will be attained or that any deviations will not be material. Investors are cautioned that forward-looking statements speak only as of the date they are made and that, except as required by law, the Partnership undertakes no obligation to update these forward-looking statements to reflect any future events or circumstances. All subsequent written or oral forward-looking statements attributable to the Partnership or to individuals acting on its behalf are expressly qualified in their entirety by this section.

Item 1. Business

Energy Resources 12, L.P. (the "Partnership") was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on December 30, 2016. The Partnership is offering common units of limited partner interest (the "common units") on a best-efforts basis with the intention of raising up to $350,000,001 of capital, consisting of 17,631,579 common units. The Partnership's offering was declared effective by the Securities and Exchange Commission ("SEC") on May 17, 2017. As of July 25, 2017, the Partnership completed the sale of the minimum offering of 1,315,790 common units. The subscribers to the common units were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time. As of December 31, 2017, the Partnership had sold 3.2 million common units for gross proceeds of $61.2 million and proceeds net of offering costs of $57.0 million. The offering will expire on the sooner of May 17, 2019 or the sale of 17,631,579 common units.

The general partner of the Partnership is Energy Resources 12 GP, LLC (the "General Partner").

Business Objective

The Partnership's primary investment objectives are to (i) acquire producing and non-producing oil and gas properties with development potential to be operated by third-party operators on-shore in the United States, and to enhance the value of the properties through drilling and other development activities, (ii) make distributions to the holders of the common units, (iii) engage in a liquidity transaction after five to seven years, in which all properties are sold and the sales proceeds are distributed to the partners, merge with another entity, or list the common units on a national securities exchange, and (iv) permit holders of common units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the common units primarily have been and will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States, and to develop those properties.

Current Developments

Oil and Gas Properties Acquisition

On November 21, 2017, Energy Resources 12 Operating Company, LLC ("Buyer"), a wholly-owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement ("Purchase Agreement") with Bruin E&P Non-Op Holdings, LLC ("Seller"), for the potential purchase of Seller's interest in certain non-operated oil and gas properties and the related rights, resulting in an approximate average 3.1% non-operated working interest in approximately 204 existing producing wells and approximately 547 future development locations, predominantly in McKenzie, Dunn, McLean and Mountrail counties of North Dakota (collectively, the "Bakken Assets"). The Buyer closed on the purchase of the Bakken Assets on February 1, 2018.

Prior to this acquisition, the Partnership owned no oil and natural gas assets. Neither the Buyer nor the Partnership will be the operator of the Bakken Assets; the current, experienced operators will continue to operate on behalf of the Partnership and other working interest owners. There are twelve current operators, including WPX Energy (NYSE: WPX), Marathon Oil (NYSE: MRO), EOG Resources (NYSE: EOG) and Continental Resources (NYSE: CLR). The Bakken Assets are located in the Bakken Shale formation, including the Antelope, Spotted Horn, Squaw Creek and Reunion Bay fields. The Bakken Shale and its close geologic cousin, the Three Forks Shale, are found in the Williston Basin, centered in North Dakota and are two of the largest oil fields in the U.S. While oil has been produced in North Dakota from the Williston Basin since the 1950s, it is only since 2007 through the application of horizontal drilling and hydraulic fracturing technologies that the Bakken has seen an increase in production activities.

The purchase price for the Bakken Assets was $87.5 million, subject to customary post-closing adjustments. The purchase price was funded by net proceeds from the Partnership's ongoing public offering, proceeds from an unsecured term loan (discussed in "Term Loan" below) and an advance from a member of the General Partner of $7.0 million. The advance does not bear interest and the member of the General Partner did not receive any compensation for the advance. The advance is planned to be repaid with future proceeds from the Partnership's ongoing public offering.

Term Loan

On January 16, 2018, the Partnership, as the borrower, entered into a loan agreement (the "Loan Agreement") with Bank of America, N.A. (the "Lender"), which provides for an unsecured Term Loan of $25 million. The Term Loan bears interest at a variable rate based on the London Inter-Bank Offered Rate (LIBOR) plus a margin of 2.00%.

The Term Loan proceeds were used in closing on the Partnership's purchase of the Bakken Assets, as described in the section titled "Oil and Gas Properties Acquisition" above. Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. Glade M. Knight, Chief Executive Officer of the General Partner and David S. McKenney, the General Partner's Chief Financial Officer, have guaranteed repayment of the Term Loan and did not receive any consideration in exchange for providing this guarantee. The Partnership intends to use proceeds from its ongoing offering to repay the Term Loan.

Advisory and Cost Sharing Agreements

In November 2017, the Partnership engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting the Buyer through closing and post-closing of the Purchase Agreement. The Partnership will pay REI a total of approximately $5.3 million for its advisory and consulting services. REI is also entitled to a fee of 5% of the gross sales price in the event the Buyer disposes any or all of the Bakken Assets, if surplus funds are available after Payout to the holders of the Partnership's common units, as defined below. REI is owned by entities that are controlled by Anthony F. Keating, III, Co-Chief Operating Officer of Energy 11 GP, LLC, and Michael J. Mallick, Co-Chief Operating Officer of Energy 11 GP, LLC. Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of Energy 11 GP, LLC as well as the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner. Energy 11 GP, LLC is the general partner of Energy 11, L.P. ("Energy 11"), a limited partnership that also invests in producing and non-producing oil and gas properties on-shore in the United States.

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11 to provide access to Energy 11's personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for the Partnership. The shared day-to-day costs will be split evenly between the two partnerships and any direct third-party costs will be paid by the party receiving the services. The shared costs will be based on actual costs incurred with no mark-up or profit for Energy 11. The agreement may be terminated at any time by either party upon 60 days written notice. As noted above, the officers and members of the Partnership's General Partner are also officers and members of the general partner of Energy 11.

Partners' Equity and Distributions

At inception, the General Partner and organizational limited partner made initial capital contributions totaling $1,000 to the Partnership. Upon closing of the minimum offering, the organizational limited partner withdrew its initial capital contribution of $990, the General Partner received Incentive Distribution Rights (defined below), and has been and will be reimbursed for its documented third party out-of-pocket expenses incurred in organizing the Partnership and offering the common units.

As of July 25, 2017, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. On October 6, 2017, the Partnership had received subscriptions for all of the common units offered at $19.00 (2,631,579), and consequently all common units offered and sold after October 6, 2017 have been and will be sold at $20.00 per common unit. As of December 31, 2017, the Partnership had completed the sale of 3,191,231 common units for gross proceeds of approximately $61.2 million and proceeds net of offering costs of approximately $57.0 million. The Partnership intends to continue to raise capital through its best-efforts offering of common units by David Lerner Associates, Inc. (the "Managing Dealer") at $20.00. Under the agreement with the Managing Dealer, the Managing Dealer receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Managing Dealer also has Dealer Manager Incentive Fees (defined below) where the Managing Dealer could receive distributions up to an additional 4% of gross proceeds of the common units sold in the Partnership's best-efforts offering as outlined in the prospectus based on the performance of the Partnership. Based on the common units sold through December 31, 2017, the Dealer Manager Incentive Fees are approximately $2.4 million, subject to Payout (defined below).

Prior to "Payout," which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights and will not pay the Dealer Manager Incentive Fees to the Managing Dealer, until Payout occurs.

The Agreement of Limited Partnership of the Partnership (the "Partnership Agreement") provides that "Payout", which is defined below, occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership's assets, will be made as follows:

First, (i) to the Record Holders of the Incentive Distribution Rights, 30%; (ii) to the Managing Dealer, the "Dealer Manager Incentive Fees", 30%, until such time as the Managing Dealer receives 4% of the gross proceeds of the common units sold; and (iii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 60%; and (ii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

All items of income, gain, loss and deduction will be allocated to each Partner's capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2017, the Partnership paid distributions of $0.598357 per common unit, or $1.5 million. The Partnership began paying distributions upon reaching the minimum offering in July 2017.

Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties, including those discussed above. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to any existing related party transactions, as well as any new significant related party transactions.

See further discussion in Note 6 titled "Related Parties" in Part II, Item 8 of this Form 10-K.

Title to Properties

As is customary in the Partnership's industry, a preliminary review of title records, which may include opinions or reports of appropriate professionals or counsel, is made at the time the Partnership acquires properties. The Partnership believes that its title to all of the various interests set forth above is satisfactory and consistent with the standards generally accepted in the oil and gas industry, subject only to immaterial exceptions that do not detract substantially from the value of the interests or materially interfere with their use in the Partnership's operations. The interests owned by the Partnership may be subject to one or more royalty, overriding royalty, or other outstanding interests (including disputes related to such interests) customary in the industry. The interests may additionally be subject to obligations or duties under applicable laws, ordinances, rules, regulations, and orders of arbitral or governmental authorities. In addition, the interests may be subject to burdens such as net profits interests, liens incident to operating agreements and current taxes, development obligations under oil and gas leases, and other encumbrances, easements, and restrictions, none of which detract substantially from the value of the interests or materially interfere with their use in the Partnership's operations.

Insurance

Since the Partnership is not the operator of any of its properties, the Partnership relies on the insurance of the operator(s) of its properties, of which the Partnership's share of the cost is allocated back to the Partnership through the Joint Operating Agreement. The Partnership's operators have insurance policies that include coverage for general liability (includes sudden and accidental pollution), physical damage to its oil and gas properties, control of well, auto liability, marine liability, worker's compensation and employer's liability, among other things.

The Partnership re-evaluates the purchase of insurance, coverage limits and deductibles annually. Future insurance coverage for the oil and gas industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that are economically acceptable. No assurance can be given that the Partnership will be able to maintain insurance in the future at rates that the Partnership considers reasonable and the Partnership may elect to self-insure or maintain only catastrophic coverage for certain risks in the future.

Competition

The oil and natural gas industry is highly competitive. The Partnership will encounter strong competition from independent oil and gas companies, master limited partnerships and from major oil and gas companies in acquiring properties, contracting for drilling equipment and arranging the services of trained personnel. Many of these competitors have financial and technical resources and staffs substantially larger than the Partnership's. As a result, the Partnership's competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than the Partnership's financial or other resources will permit.

The Partnership also may be affected by competition for drilling rigs, human resources and the availability of related equipment. In the past, the oil and natural gas industry has experienced shortages of drilling rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases. The Partnership is unable to predict when, or if, such shortages may occur or how they would affect the Partnership's development and exploitation program.

Seasonal Nature of Business

Seasonal weather conditions and lease stipulations can limit the Partnership's drilling and producing activities and other operations in certain areas where the Partnership may acquire producing properties. These seasonal anomalies can pose challenges for meeting the Partnership's drilling objectives and increase competition for equipment, supplies and personnel during the drilling season, which could lead to shortages and increased costs or delay the Partnership's operations. Generally, demand for natural gas is higher in summer and winter months. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter natural gas requirements during off–peak months. This can lessen seasonal demand fluctuations.

Environmental, Health and Safety Matters and Regulation

The Partnership's operations will be subject to stringent and complex federal, state and local laws and regulations that govern the oil and natural gas industry, as well as regulations that protect the environment from the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;
- require the installation of pollution control equipment in connection with operations;
- place restrictions or regulations upon the use or disposal of the material utilized in the Partnership's operations;
- restrict the types, quantities and concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;
- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas;
- require remedial measures to mitigate or remediate pollution from former and ongoing operations, and may also require site restoration, pit closure and plugging of abandoned wells; and
- require the expenditure of significant amounts in connection with worker health and safety.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal, state and local agencies frequently revise environmental laws and regulations, and such changes could result in increased costs for environmental compliance, such as waste handling, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on the Partnership's operating costs. In general, the oil and natural gas industry has recently been the subject of increased legislation and regulatory attention with respect to environmental matters. The US Environmental Protection Agency, or EPA, has identified environmental compliance by the energy extraction sector as one of its enforcement initiatives for fiscal years 2017 to 2019, although it is unclear about the outlook for this initiative with the current administration. Even if regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental regulation may continue for the long term.

The following is a summary of some of the existing laws, rules and regulations to which the Partnership's business operations are subject.

Solid and Hazardous Waste Handling

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous solid waste. Although oil and natural gas waste generally is exempt from regulations as hazardous waste under RCRA, the Partnership expects its operators to generate waste as a routine part of their operations that may be subject to RCRA. Although a substantial amount of the waste expected to be generated is regulated as non–hazardous solid waste rather than hazardous waste, there is no guarantee that the EPA or individual states will not adopt more stringent requirements for the handling of non–hazardous or exempt waste or categorize some non–hazardous or exempt waste as hazardous in the future. For example, following the filing of a lawsuit in the U.S. District Court for the District of Columbia in May 2016 by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes, the EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the District Court on December 28, 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Non-exempt waste is subject to more rigorous and costly disposal requirements. Any such change could result in substantial costs to manage and dispose of waste, which could have a material adverse effect on the Partnership's results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, imposes strict, joint and several liability for costs of investigation and remediation and for natural resource damages without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so-called potentially responsible parties, or PRPs, include the current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance found at the site. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of the Partnership's operators' expected operations, the operators will generate wastes that may fall within CERCLA's definition of hazardous substance and may dispose of these wastes at disposal sites owned and operated by others. Comparable state statutes may not provide a comparable exemption for petroleum, and there is no guarantee that federal law will not adopt more stringent requirements with respect to the petroleum substances. The Partnership may also be the owner of sites on which hazardous substances have been released. If contamination is discovered at a site on which the Partnership is or has been an owner or to which the Partnership sent hazardous substances, the Partnership could be liable for the costs of investigation and remediation and natural resources damages. Further, the Partnership could be required to suspend or cease operations in contaminated areas.

The Partnership may acquire producing properties that have been used for oil and natural gas exploration and production for many years. Hazardous substances, wastes or hydrocarbons may have been released on or under the properties to be acquired by the Partnership, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of the properties the Partnership has or may acquire may have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under Partnership control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. In the future, the Partnership could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Clean Water Act

The Federal Water Pollution Control Act, also known as the Clean Water Act, and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has issued final rules outlining its position on the federal jurisdictional reach over waters of the United States. Litigation surrounding this rule is ongoing. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non–compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of wastes, the Partnership may be liable for penalties and cleanup and response costs. The federal Clean Water Act only regulates surface waters. However most of the state analogs to the Clean Water Act also regulate discharges which impact groundwater.

Safe Drinking Water Act and Hydraulic Fracturing

Many of the properties the Partnership may own or expect to acquire will require additional drilling operations to fully develop the reserves attributable to the properties. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Hydraulic fracturing activities are typically regulated by state oil and gas commissions but not at the federal level, as the federal Safe Drinking Water Act expressly excludes regulation of these fracturing activities (except for fracturing activities involving the use of diesel).

In prior sessions, Congress has considered legislation to amend the federal Safe Drinking Water Act to remove the exemption for hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. This legislation has not passed. A number of states, local and regional regulatory authorities have or are considering hydraulic fracturing regulation and other regulations imposing new or more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations or restricting or banning hydraulic fracturing. Further, the EPA has issued an effluent limitations guideline prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned treatment plants.

Due to public concerns raised regarding potential impacts of hydraulic fracturing on groundwater quality, there have been recent developments at the federal, state, regional and local levels that could result in regulation of hydraulic fracturing becoming more stringent and costly. In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources, concluding that “water cycle” activities associated with hydraulic fracturing may impact drinking water resources “under some circumstances,” including water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. This report could result in additional regulatory scrutiny that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and business.

If new laws or regulations imposing significant restrictions or conditions on hydraulic fracturing activities are adopted in areas where the Partnership acquires properties that require additional drilling, the Partnership could incur substantial compliance costs and such requirements could adversely delay or restrict its ability to conduct fracturing activities on its assets.

Toxic Substances Control Act and Hydraulic Fracturing

On August 4, 2011, Earthjustice and 114 other organizations petitioned the EPA under section 21 of the Toxic Substances Control Act (TSCA) to impose various requirements on E&P chemical substances and mixtures. In a letter dated November 2, 2011, EPA informed petitioners that it denied the TSCA section 4 request and in a letter dated November 23, 2011, the EPA informed petitioners that it granted in part the TSCA petition in part and granted the TSCA petition in part. The EPA issued a notice seeking public comment on May 19, 2014; the comment period has not closed. This is part of the EPA’s general review of hydraulic fracturing.

Oil Pollution Act

The primary federal law for oil spill liability is the Oil Pollution Act, or OPA, which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain "responsible parties" related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. A liable "responsible party" includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge on properties it acquires, the Partnership may be liable for costs and damages.

Air Emissions

The operations of the Partnership's operators are subject to the federal Clean Air Act, or CAA, and analogous state laws and local ordinances governing the control of emissions from sources of air pollution. The CAA and analogous state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (or toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or seek injunctive relief, requiring the Partnership to forego construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation. The EPA rules include standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound, or VOC, emissions from natural gas not sent to the gathering line during well completion either by flaring, using a completion combustion device, or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of "green completions." The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. The EPA has made and could continue to make revisions to clarify these rules in response to stakeholder comments. These rules and any revised rules may require the installation of equipment to control emissions on producing properties the Partnership acquires.

On June 3, 2016, the EPA expanded its regulatory coverage in the oil and gas industry with additional regulated equipment categories, and the addition of new rules limiting methane emissions from new or modified sites and equipment. The EPA attempted to suspend enforcement of the methane rule, but this action was challenged on appeal and was ruled improper. The EPA is reported to be considering rulemaking to rescind or revise the rule. Simultaneously with the additional methane rules, the EPA released a rule defining site aggregation for air permitting purposes. Under this rule, it is possible that some sites could require additional permitting under the Clean Air Act, an outcome that could result in costs and delays to the Partnership's operations. In February 2018, the Bureau of Land Management ("BLM") proposed a rule to revise certain requirements in its rules regarding the control of methane emissions. If adopted or enacted, additional regulations on air emissions is likely to result in increased compliance costs and additional operating restrictions on the Partnership's business.

On November 18, 2016, the BLM published a final rule, which became effective on January 17, 2017, that was intended to reduce waste of natural gas from venting, flaring, and leaks during oil and natural gas production activities on onshore Federal and Indian leases. Unlike the somewhat overlapping EPA regulations, which apply to new, modified and reconstructed sources, the BLM's 2016 rule was drafted to address existing facilities, including a substantial number of existing wells that are likely to be marginal or low-producing, including leak detection and repair and other requirements regarding methane emissions. Just as the EPA has proposed a temporary stay of some of its requirements related to methane emissions contained in NSPS 0000a, the EPA is reconsidering some of these requirements, BLM issued a proposed rule on February 12, 2018, that concludes that the costs the rule would impose would exceed the benefits it is expected to generate and therefore reduced certain compliance burdens deemed to be unnecessary, including requirements to write waste minimization plans, meet methane capture targets and use equipment that meets certain technical standards. It is too recent an event to determine the impact these proposed regulatory changes may have on oil and gas producers.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All proposed exploration and development plans on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Climate Change Legislation

More stringent laws and regulations relating to climate change and greenhouse gases (“GHGs”) may be adopted in the future and could cause the Partnership to incur material expenses in complying with them. Both houses of Congress have considered legislation to reduce emissions of GHGs, but no legislation has yet passed. In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions; although the Supreme Court struck down the permitting requirements, it upheld the EPA’s authority to control GHG emissions when a permit is required due to emissions of other pollutants. The EPA has adopted measures to reduce methane and other GHGs, as discussed above in “Air Emissions.”

In addition, the EPA has adopted a mandatory GHG emissions reporting program that imposes reporting and monitoring requirements on various types of facilities and industries including onshore and offshore oil and natural gas production, processing, transmission, storage, and distribution facilities.

Because of the lack of any comprehensive legislative program addressing GHGs, there is a great deal of uncertainty as to how and whether federal regulation of GHGs might take place. In addition to possible federal regulation, a number of states, individually and regionally as well as some localities, also are considering or have implemented GHG regulatory programs or other steps to reduce GHG emissions. These potential regional, state and local initiatives may result in so-called cap and trade programs, under which overall GHG emissions are limited and GHG emissions are then allocated and sold, and possibly other regulatory requirements, that could result in the Partnership incurring material expenses to comply, e.g., by being required to purchase or to surrender allowances for GHGs resulting from its operations. The federal, regional and local regulatory initiatives also could adversely affect the marketability of the oil and natural gas the Partnership produces. The impact of such future programs cannot be predicted, but the Partnership does not expect its operations to be affected any differently than other similarly situated domestic competitors.

Endangered Species Act

The Endangered Species Act was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities that would harm the species or that would adversely affect that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The Partnership’s operators may conduct operations on oil and natural gas leases that have species that are listed and species that could be listed as threatened or endangered under the act. The U.S. Fish and Wildlife Service designates the species’ protected habitat as part of the effort to protect the species. A protected habitat designation or the mere presence of threatened or endangered species could result in material restrictions to use of the land and may materially delay or prohibit land access for oil and natural gas development. It also may adversely impact the value of the affected properties that the Partnership acquires. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where the Partnership might conduct operations could result in limitations or prohibitions on its activities and could adversely impact the value of its leases.

OSHA and Other Laws and Regulation

The Partnership will be subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. These laws and the implementing regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right–to–know regulations under the Title III of CERCLA and similar state statutes require that the Partnership organizes and/or discloses information about hazardous materials used or produced in the Partnership’s operations.

Other Regulation of the Oil and Natural Gas Industry

The oil and natural gas industry is extensively regulated by numerous federal, state, local and tribal authorities. Rules and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and the potential for financial sanctions for noncompliance. Also, numerous departments and agencies, both federal and state, are authorized by statute to issue rules and regulations binding on the oil and natural gas industry and its individual members, some of which carry substantial penalties for failure to comply. Although the regulatory burden on the oil and natural gas industry increases the Partnership's cost of doing business and, consequently, affects the Partnership's profitability, these burdens generally do not affect the Partnership any differently or to any greater or lesser extent than they affect other companies in the industry with similar types, quantities and locations of production.

Drilling and Production

Statutes, rules and regulations affecting exploration and production undergo constant review and often are amended, expanded and reinterpreted, making difficult the prediction of future costs or the impact of regulatory compliance attributable to new laws and statutes. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects its profitability. The drilling and production operations performed by the Partnership's contracted operators will be subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring permits for the drilling of wells, drilling bonds and reports concerning operations. Most states and some counties and municipalities in which the Partnership operates also regulate one or more of the following:

- the location of wells;
- the method of drilling, completing and operating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- the marketing, transportation and reporting of production;
- notice to surface owners and other third parties; and
- produced water and waste disposal.

State and federal regulations are generally intended to prevent waste of oil and natural gas, protect correlative rights to produce oil and natural gas between owners in a common reservoir or formation, control the amount of oil and natural gas produced by assigning allowable rates of production and control contamination of the environment. Pipelines and natural gas plants operated by other companies that provide midstream services to us are also subject to the jurisdiction of various federal, state and local authorities, which can affect the Partnership's operations. State laws also regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties.

States generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within their respective jurisdictions. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

In addition, a number of states and some tribal nations have enacted surface damage statutes, or SDAs. These laws are designed to compensate for damage caused by oil and natural gas development operations. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and require specific payments by the operator to surface owners/users in connection with exploration and producing activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

The Partnership will not control the availability of transportation and processing facilities that may be used in the marketing of its production. For example, the Partnership may have to shut–in a productive natural gas well because of a lack of available natural gas gathering or transportation facilities.

If the Partnership conducts operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various non–discrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by BLM, Bureau of Safety and Environmental Enforcement, Bureau of Indian Affairs, tribal or other appropriate federal, state and/or Indian tribal agencies.

The Mineral Leasing Act of 1920, or the Mineral Act, prohibits ownership of any direct or indirect interest in federal onshore oil and natural gas leases by a foreign citizen or a foreign entity except through equity ownership in a corporation formed under the laws of the United States or of any U.S. State or territory, and only if the laws, customs, or regulations of their country of origin or domicile do not deny similar or like privileges to citizens or entities of the United States. If these restrictions are violated, the oil and natural gas lease can be canceled in a proceeding instituted by the United States Attorney General. The Partnership qualifies as an entity formed under the laws of the United States or of any U.S. State or territory. Although the regulations promulgated and administered by the BLM pursuant to the Mineral Act provide for agency designations of non–reciprocal countries, there are presently no such designations in effect. It is possible that the holders of the Partnership's common units may be citizens of foreign countries and do not own their common units in a U.S corporation or even if such interest is held through a U.S. corporation, their country of citizenship may be determined to be non–reciprocal countries under the Mineral Act. In such event, any federal onshore oil and natural gas leases held by us could be subject to cancellation based on such determination.

Federal Regulation of Oil, Natural Gas and Natural Gas Liquids, including Regulation of Transportation

The availability, terms and cost of transportation significantly affect sales of natural gas. The interstate transportation and sale for resale of natural gas are subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission, or FERC. Federal and state regulations govern the price and terms for access to natural gas pipeline transportation. FERC's regulations for interstate natural gas transmission in some circumstances may also affect the intrastate transportation of natural gas. FERC regulates the rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines under the Natural Gas Act as well as under Section 311 of the Natural Gas Policy Act.

Under FERC's current regulatory regime, interstate transportation services must be provided on an open-access, non-discriminatory basis at cost-based rates or at market-based rates if the transportation market at issue is sufficiently competitive. The FERC-regulated tariffs, under which interstate pipelines provide such open-access transportation service, contain strict limits on the means by which a shipper releases its pipeline capacity to another potential shipper, which provisions include FERC's "shipper-must-have-title" rule. Violations by a shipper (i.e., a pipeline customer) of FERC's capacity release rules or shipper-must-have-title rule could subject a shipper to substantial penalties from FERC.

With respect to its regulation of natural gas pipelines under the NGA, FERC has not generally required the applicant for construction of a new interstate natural gas pipeline to produce evidence of the greenhouse gas ("GHG") emissions of the proposed pipeline's customers. In August 2017, the U.S. Circuit Court of Appeals for the DC Circuit issued a decision remanding a natural gas pipeline certificate application to FERC, which required FERC to revise its environmental impact statement for the proposed pipeline to take into account GHG carbon emissions from downstream power plants using natural gas transported by the new pipeline. It is too early to determine the impacts of this Court decision, but it could be significant.

FERC has also issued several other generally pro–competitive policy statements and initiatives affecting rates and other aspects of pipeline transportation of natural gas. On May 31, 2005, FERC generally reaffirmed its policy of allowing interstate pipelines to selectively discount their rates in order to meet competition from other interstate pipelines. On June 15, 2006, FERC issued an order in which it declined to establish uniform standards for natural gas quality and interchangeability, opting instead for a pipeline–by–pipeline approach. On June 19, 2006, in order to facilitate development of new storage capacity, FERC established criteria to allow providers to charge market–based (*i.e.*, negotiated) rates for storage services. On June 19, 2008, the FERC removed the rate ceiling on short–term releases by shippers of interstate pipeline transportation capacity.

Although natural gas prices are currently unregulated, Congress historically has been active in the area of natural gas regulation. The Partnership cannot predict whether new legislation to regulate natural gas might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the properties the Partnership may acquire. Sales of condensate and natural gas liquids are not currently regulated and are made at market prices.

Sales of the Partnership's oil and natural gas liquids are also affected by the availability, terms and costs of transportation. The rates, terms, and conditions applicable to the interstate transportation of oil and natural gas liquids by pipelines are regulated by the FERC under the Interstate Commerce Act ("ICA"). The FERC has implemented a simplified and generally applicable ratemaking methodology for interstate oil and natural gas liquids pipelines to fulfill the requirements of Title XVIII of the Energy Policy Act of 1992 comprised of an indexing system to establish ceilings on interstate oil and natural gas liquids pipeline rates. In addition, FERC issued a declaratory order in November 2017, involving a marketing affiliate of an oil pipeline, which held that certain arrangements between an oil pipeline and its marketing affiliate would violate the ICA's anti-discrimination provisions. FERC held that providing transportation service to affiliates at what is essentially the variable cost of the movement, while requiring non-affiliated shippers to pay the (higher) filed tariff rate, would violate the ICA. Rehearing has been sought of this FERC order by various pipelines. It is too recent an event to determine the impact this FERC order may have on oil pipelines, their marketing affiliates, and the price of oil and other liquids transported by such pipelines.

Gathering service, which occurs on pipeline facilities located upstream of FERC-jurisdictional interstate transportation services, is regulated by the states onshore and in state waters. Depending on changes in the function performed by particular pipeline facilities, FERC has in the past reclassified certain FERC-jurisdictional transportation facilities as non-jurisdictional gathering facilities and FERC has reclassified certain non-jurisdictional gathering facilities as FERC-jurisdictional transportation facilities. Any such changes could result in an increase to our costs of transporting gas to point-of-sale locations.

The pipelines used to gather and transport natural gas being produced by us are also subject to regulation by the U.S. Department of Transportation (“DOT”) under the Natural Gas Pipeline Safety Act of 1968, as amended (“NGPSA”), the Pipeline Safety Act of 1992, as reauthorized and amended (“Pipeline Safety Act”), and the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011. The DOT Pipeline and Hazardous Materials Safety Administration (“PHMSA”) has established a risk–based approach to determine which gathering pipelines are subject to regulation and what safety standards regulated gathering pipelines must meet. In addition, the PHMSA had initially considered regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In October 2015, the PHMSA issued proposed new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and that operators establish a timeline for inspections of affected pipelines following extreme weather events or natural disasters. If such revisions to gathering line regulations and liquids pipelines regulations are enacted by PHMSA, the Partnership could incur significant expenses.

Transportation of the Partnership’s oil, natural gas liquids and purity components (ethane, propane, butane, iso–butane, and natural gasoline) by rail is also subject to regulation by the DOT’s PHMSA and the DOT’s Federal Railroad Administration (“FRA”) under the Hazardous Materials Regulations at 49 CFR Parts 171-180 (“HMR”), including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.

Exports of US Crude Oil Production and Natural Gas Production

The federal government has recently ended its decades-old prohibition of exports of oil produced in the lower 48 states of the US. The general perception in the industry is that ending the prohibition of exports of oil produced in the US will be positive for producers of U.S. oil. In addition, the U.S. Department of Energy (“DOE”) authorizes exports of natural gas, including exports of natural gas by pipelines connecting U.S. natural gas production to pipelines in Mexico, which are expected to increase significantly with the changes taking place in the Mexican government’s regulations of the energy sector in Mexico. In addition, the DOE authorizes the export of liquefied natural gas (“LNG”) through LNG export facilities, the construction of which are regulated by FERC. In the third quarter of 2016, the first quantities of natural gas produced in the lower 48 states of the U.S. were exported as LNG from the first of several LNG export facilities being developed and constructed in the U.S. Gulf Coast region. While it is too recent an event to determine the impact this change may have on the Partnership’s operations or the Partnership’s sales of natural gas, the perception in the industry is that this will be a positive development for producers of U.S. natural gas.

Other Regulation

In addition to the regulation of oil and natural gas pipeline transportation rates, the oil and natural gas industry generally is subject to compliance with various other federal, state and local regulations and laws. Some of those laws relate to occupational safety, resource conservation and equal employment opportunity. The Partnership does not believe that compliance with these laws will have a material adverse effect upon its operations.

Employees

The Partnership has no officers, directors or employees. Instead, the General Partner manages the day to day affairs of the Partnership. All decisions regarding the management of the Partnership made by the General Partner will be made by the Board of Directors of the General Partner and its officers.

General Corporate Information

Energy Resources 12, L.P. is a Delaware limited partnership founded in 2016 with principal offices at 120 W 3rd Street, Suite 220, Fort Worth, Texas 76102. The Partnership can be reached at (817) 882-9192 and the Partnership website address is www.energyresources12.com. The Partnership makes available, free of charge through its Internet website, its annual report on Form 10-K and quarterly reports on Form 10-Q, and amendments to those reports filed or furnished pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after the Partnership electronically files such material with, or furnishes it to, the SEC. Information contained on the Partnership’s website is not incorporated by reference into this report.

Item 1A. Risk Factors

Risks Related to an Investment in the Partnership

The chief executive officer and the chief financial officer have limited prior experience in investing in oil and gas properties.

The experience of the Partnership's chief executive officer and chief financial officer is primarily in the real estate industry. This is the second oil and gas program in which the Partnership's chief executive officer and chief financial officer have participated. You should consider an investment in the Partnership in light of the risks, uncertainties and difficulties frequently encountered by management operating in a new industry.

The Partnership has not engaged any personnel other than its chief executive officer and chief financial officer who have oil and gas experience.

The Partnership will rely on the General Partner (who currently only employs the chief executive officer and the chief financial officer) and independent oil and gas professionals to identify suitable investments. To the extent the General Partner relies on independent oil and gas professionals to provide these services, the Partnership may face competing demands on their time. Consequently, at times when the Partnership has capital ready for investment, it may experience delays in locating and evaluating suitable properties. The Partnership has agreed to share certain resources, including personnel, utilized by Energy 11 and engaged energy professionals as contractors for oversight of the Partnership's Assets acquired on February 1, 2018, any additional properties the Partnership may acquire and for other Partnership administrative functions. Since these resources will be shared or engaged on a part-time basis, these personnel may not have adequate time to devote to the Partnership. In the future, the General Partner may either hire additional personnel to support the acquisition and oversight processes for the Partnership or engage independent industry professionals as contractors to provide these services; however, there can no assurance that the Partnership will be able to hire or engage a sufficient number of qualified people to provide the required services.

The Partnership has limited prior operating history and limited established financing sources.

The Partnership, which was formed in 2016, has limited operating history, and accordingly, has limited direct costs and administrative costs associated with prior operations. In addition, since its formation, the Partnership has not owned or operated any oil and gas assets until February 2018. You should consider an investment in the Partnership in light of the risks, uncertainties and difficulties frequently encountered by companies that are, like the Partnership, in their early stage of development. The Partnership cannot guarantee that it will succeed in achieving its goals, and its failure to do so could cause you to lose all or a portion of your investment.

Distributions to the Partnership's common unitholders may not be sourced from its cash generated from operations but from offering proceeds or indebtedness, and therefore the Partnership's distributions during certain periods may exceed earnings and cash flows from operations, and this will decrease the Partnership's distributions in the future; furthermore, the Partnership cannot guarantee that investors will receive any specific return on their investment.

The General Partner has the right to make distributions from the proceeds of borrowings and capital contributions. It is likely that all or a part of distributions to common unitholders during the early years of the Partnership's operations will represent the proceeds of capital contributions, rather than cash generated in its operations. This is because as proceeds are raised in the offering, it is not always possible immediately to invest them in oil and gas properties that generate the desired return on investment. There may be a "lag" or delay between the raising of offering proceeds and their investment in oil and gas properties. Investors who acquire common units relatively early in the Partnership's offering, as compared with later investors, may receive a greater return of offering proceeds as part of the earlier distributions. Offering proceeds that are returned to investors as part of distributions to them will not be available for investments in oil and gas properties. In addition, during certain periods, the Partnership expects that distributions may exceed the amount of earnings and cash flows from operations during such periods. The payment of distributions will decrease the cash available to invest in oil and gas properties and will reduce the amount of distributions the Partnership may make in the future. The Partnership cannot and does not guarantee that investors will receive any specific return on their investment. Further, there is no limitation on the amount of distributions that can be funded from offering proceeds or financing proceeds. Because cash generated from Partnership operations will be comingled and is fungible with cash received from capital contributions and indebtedness, the Partnership is unable to determine a point in time when distributions will no longer be sourced from capital contributions and proceeds of borrowings. Any distributions that are made with the proceeds of capital contributions may constitute a return of capital.

The past performance of programs sponsored or affiliated with members of the General Partner is not an indicator of the Partnership's future performance.

You should not rely upon the past performance of other programs sponsored by or affiliated with members of the General Partner as an indicator of the Partnership's future performance.

The Partnership depends on key personnel, the loss of any of whom could materially adversely affect future operations.

The Partnership's success will depend to a large extent upon the efforts and abilities of Messrs. Knight and McKenney, the chief executive officer and chief financial officer. The loss of the services of one or more of these key employees could have a material adverse effect on the Partnership. The Partnership does not maintain key-man life insurance with respect to any employees. The Partnership's business will also be dependent upon its ability to attract and retain qualified personnel. Acquiring and keeping these personnel could prove more difficult or cost substantially more than estimated. This could cause the Partnership to incur greater costs, or prevent it from pursuing its acquisition and development strategy as quickly as the Partnership would otherwise wish to do.

Because the Partnership has not yet identified or selected all the properties that it may acquire, this is a "blind pool" offering. This means you may not be able to evaluate the Partnership's properties before making your investment decision.

The Partnership may not select additional properties for acquisition until after you invest in the Partnership. You may not have an opportunity before purchasing units to evaluate geophysical, geological, economic or other pertinent information regarding the prospects to be selected. Delays are likely in the investment of proceeds from your subscription because the offering period for the Partnership can extend over a number of months. If the Partnership selects a property for acquisition by the Partnership during the offering period, the Partnership will file a prospectus supplement describing the property and its proposed acquisition. If you subscribe for units prior to any such supplement you will not be permitted to withdraw your subscription as a result of the selection of any property.

The common units are not liquid and your ability to resell your common units will be limited by the absence of a public trading market and substantial transfer restrictions.

If you invest in the Partnership, then you must assume the risks of an illiquid investment. The common units generally will not be liquid because there is not a readily available market for the sale of common units, and one is not expected to develop. Further, although the Partnership Agreement contains provisions designed to permit the listing of common units on a national securities exchange, the Partnership does not currently intend to list the common units on any exchange or in the over-the-counter market.

If the General Partner elects to cause the Partnership to make distributions rather than reinvesting the cash flow in its business, the Partnership may be required to sell or farm-out properties or to elect not to participate in exploration or development drilling activities on its properties, which activities could turn out to be profitable.

If the Partnership were presented with an exploration or development drilling or other opportunity on its properties, and funding the opportunity would require the Partnership's cash that is required in order to follow its distribution policy or for other purposes approved by the General Partner, the General Partner may elect to cause the Partnership to sell or farm-out the opportunity or decline to participate in the opportunity, even if the General Partner determines that the opportunity could have a favorable rate of return. The General Partner will have the right to cause the Partnership to participate in opportunities that will use the Partnership's cash otherwise than in accordance with the distribution policy if the General Partner determines that pursuing such opportunity is in the best interests of the Partnership.

The General Partner will be subject to conflicts of interest in operating the Partnership, including conflicts of interest arising out of the General Partner's ownership of the incentive distribution rights. The Partnership Agreement limits the General Partner's fiduciary duties to the Partnership in connection with these conflicts of interest.

The General Partner will be subject to conflicts of interest in operating the Partnership's business. These conflicts include:

- conflicts caused by competition with other oil and gas partnerships that have been formed or may be formed by affiliates of the General Partner in the future, including competition for properties to be acquired;
- conflicts caused by competition for the General Partner's time and attention with other partnerships that the General Partner and its affiliates do and may sponsor and/or manage;
- conflicts caused by the sale of properties to programs that have been or may be formed by the General Partner and its affiliates in the future;
- conflicts caused by the guarantee by Messrs. Knight and McKenney of the Partnership's Term Loan
- conflicts caused by the incentive distribution rights which may cause the General Partner to acquire properties or conduct operations that are more risky to the Partnership, or to sell properties, in order to generate distributions from the incentive distribution rights; and
- conflicts caused by the management fee the Partnership will pay to the General Partner since its compensation is a percentage of total gross equity proceeds raised in this offering.

The Partnership Agreement provides that the General Partner will have no liability to the Partnership or the holders of the common units for decisions made, if such decisions are made in good faith. In addition, the Partnership Agreement provides that if the General Partner receives a fairness opinion regarding the sale price of a property or in connection with a merger or the listing of the Partnership's common units on a national securities exchange, including transactions that involve affiliates of the General Partner, the General Partner will be deemed to have acted in good faith.

The Incentive Distribution Rights owned by the General Partner may cause the Partnership to invest in properties with higher risks.

The General Partner owns the incentive distribution rights which entitle the General Partner to distributions only after Payout occurs. Consequently, the incentive distribution rights may cause the General Partner to acquire properties or conduct operations that are more risky to the Partnership than other business opportunities that are available to the Partnership since the General Partner's economic interest is tied to appreciation in value of the properties acquired, and not just a return of invested capital. In addition, the incentive distribution rights may create conflicts of interest in connection with the sale of properties if the sale of properties will change the likelihood of distributions with respect to the incentive distribution rights compared with retaining the properties.

There are conflicts of interest for the members of the General Partner because they are required to spend time on activities with other entities, and these other entities may compete with the Partnership in its business activity.

Messrs. Knight and McKenney, the chief executive officer and chief financial officer, respectively, will engage in unrelated business activities, either for their own account or on behalf of other partnerships, corporations or other entities in which they have an interest. Messrs. Knight and McKenney are also chief executive officer and chief financial officer, respectively, of Energy 11 GP, LLC, which manages working and other interests in oil and gas properties for Energy 11. This entity shares similar investment objectives and policies and may compete against the Partnership. Thus, the conflicts of interest experienced by management of the General Partner in allocating management time and efforts between the Partnership and Energy 11 GP, LLC may be particularly acute. Because management of the General Partner is required to spend time on other activities, there may be instances when they may not be able to assist the Partnership with certain matters and, as a result, the Partnership may be negatively impacted.

Messrs. Knight and McKenney may form additional limited partnerships and other entities, and such companies may engage in activities similar to the Partnership. Companies organized by management of the General Partner in the future could have fees and other benefits payable to them (or to companies owned by them) which are more favorable than the fees and benefits payable by the Partnership to them (or to companies owned by them). The effect of this could be that management of the General Partner would spend more time on the activities of these other companies than on the Partnership's activities, and/or prefer one or more of these companies to the Partnership with respect to actions such as the sale of properties.

The General Partner has sole responsibility for conducting the Partnership's business and managing its operations. The General Partner and its affiliates will have conflicts of interest, which may permit them to favor their own interests to the detriment of holders of the Partnership's common units.

Conflicts of interest may arise between the General Partner and its respective affiliates on the one hand, and the Partnership and the holders of its common units, on the other hand. In resolving these conflicts of interest, the General Partner may favor its own interests and the interests of its owners over the interests of holders of the Partnership's common units. These conflicts include, among others, the following situations:

- neither the Partnership Agreement nor any other agreement requires affiliates of the General Partner to pursue a business strategy that favors the Partnership or to refer any business opportunity to the Partnership;
- the General Partner determines the amount and timing of its asset purchases and sales, capital expenditures and borrowings, each of which can affect the amount of cash that is distributed to holders of the Partnership's common units or used to service its debt obligations;
- the General Partner controls the enforcement of obligations owed to the Partnership by the General Partner and its affiliates; and
- the General Partner decides whether to retain separate counsel, accountants or others to perform services for the Partnership.

Amounts paid to the General Partner, regardless of success of the Partnership's activities, will reduce the cash the Partnership has available for distribution.

The General Partner and its affiliates will receive the annual management fee, paid quarterly, of 0.5% of total gross equity proceeds raised in this offering after the first asset purchase made by the Partnership, reimbursement of third-party costs incurred in connection with the formation of the Partnership and the Partnership's business activities and will be reimbursed for general and administrative costs of the general partner allocable to the Partnership regardless of the Partnership's success in acquiring, developing and operating properties. The fees and direct costs to be paid to the General Partner will reduce the amount of cash distributions to investors. With respect to third-party costs, the General Partner has sole discretion on behalf of the Partnership to select the provider of the services or goods and the provider's compensation.

Because the General Partner has discretion to determine the amount and timing of any distribution the Partnership may make, there is no guaranty that cash distributions will be paid by the Partnership in any amount or frequency even if its operations generate revenues.

The timing and amount of distributions will be determined in the sole discretion of the General Partner. The level of distributions, when made, will primarily be dependent upon the Partnership's levels of revenue, among other factors. Distributions may be reduced or deferred, in the discretion of the General Partner, to the extent that the Partnership's revenues are used or reserved for any of the following:

- compensation and fees paid to the General Partner and its affiliates as described above in "— Amounts paid to the General Partner, regardless of success of the Partnership's activities, will reduce cash distributions;"
- the acquisition of primarily non-operated producing and non-producing oil and gas interests considered in the best interest of the Partnership by the General Partner;
- repayment of borrowings;
- cost overruns on drilling, completion or operating activities;
- remedial work to improve a well's producing capability;
- uninsured losses from operational risks including liability for environmental damages;
- direct costs and general and administrative expenses of the Partnership;
- reserves, including a reserve for the estimated costs of eventually plugging and abandoning the wells; or
- indemnification of the General Partner and its affiliates by the Partnership for losses or liabilities incurred in connection with the Partnership's activities.

Further, because the Partnership's investments will be in depleting assets, unless reinvested, Partnership revenues and the amount available for distribution to partners will decline with the passage of time. Accordingly, there can be no assurance that the Partnership will be able to make regular distributions or that distributions will be made at any consistent rate or frequency.

The Partnership may be unable to sell its properties, merge with another entity or list the common units on a national securities exchange within its planned timeline or at all.

Beginning five to seven years after the termination of this offering, the Partnership plans either to sell its properties and distribute the proceeds of the sale, after payment of liabilities and expenses, to its partners, merge with another entity, or list the common units on a national securities exchange. The decision to sell its properties will be based on a number of factors, including the demand for oil and natural gas assets in general, the price of oil, gas and other hydrocarbons which the Partnership's properties produce, domestic and foreign supply of and demand for oil, natural gas and other hydrocarbons, the value of the Partnership's assets, the projected amount of the Partnership's oil and gas reserves, whether the planned development of the properties acquired has been finished by the operator, general economic conditions and other factors that are out of the Partnership's control. The decision to sell the Partnership's properties or merge with another entity will also be dependent upon any liabilities that the Partnership may be subject to, including contingent liabilities and conditions prevailing in the merger and acquisition market at the time. In addition, the ability to list its common units on a national securities exchange will depend on a number of factors, including the amount of assets, revenues and earnings that the Partnership has at the time of listing, the then existing market for oil and gas master limited partnerships, the state of the U.S. securities markets, the Partnership's ability to meet the requirements of national securities exchanges, securities laws and regulations and other factors. If the Partnership is unable to either sell its properties, merge or list the common units on a national securities exchange in accordance with its current plans, you may be unable to sell or otherwise transfer your common units and you may lose some or all of your investment. While the Partnership plans to seek a liquidity event within five to seven years, the Partnership Agreement does not obligate the General Partner to cause a liquidity event within that timeline. The timing of a liquidity event will be dependent upon many factors, including prevailing market conditions, and the Partnership Agreement gives the Partnership flexibility on timing so that the Partnership is not forced to act during periods of low oil and gas prices, or other disadvantageous situations.

The ability to spread the risks of property acquisitions among a number of properties will be reduced if less than the maximum offering proceeds are received and fewer acquisitions are consummated.

The Partnership's maximum offering proceeds may not exceed $350 million. There are no other requirements regarding the amount of offering proceeds to be received by the Partnership. Generally, the less offering proceeds received the fewer properties the Partnership would acquire, which would decrease the Partnership's ability to spread the risks of acquisition and development of the Partnership's properties.

There may be a conflict of interest with the General Partner's chief executive officer and chief financial officer because they have guaranteed the unsecured Term Loan and a member of the General Partner has made an advance to the Partnership.

In January 2018, the Partnership obtained an unsecured Term Loan in a principal amount of $25 million to fund the purchase of oil and gas properties located in North Dakota. This Term Loan has been guaranteed by Mr. Knight, chief executive officer of the General Partner, and Mr. McKenney, chief financial officer. In addition, in connection with the purchase of the Bakken Assets, the Partnership received an advance from a member of the General Partner of $7.0 million. The Partnership expects to repay this debt and the advance with proceeds of the Partnership's ongoing public offering. This could present a conflict of interest for Messrs. Knight and McKenney since their personal interests would be adversely affected if the offering is not successful for any reason.

The Partnership's Term Loan may limit the Partnership's ability to make distributions to holders of its common units and may limit its ability to capitalize on acquisitions and other business opportunities.

The Partnership's Term Loan contains covenants limiting the Partnership's ability to incur indebtedness and matures in January 2019. If the Partnership cannot repay or refinance debt, it may be limited in acquiring additional assets or investing in its existing assets.

The amount of indebtedness that the Partnership may incur is not limited by the terms of the Partnership Agreement.

The General Partner intends to limit the amount of borrowing to 50% of the Partnership's total capitalization on an annual basis. However, the Partnership Agreement does not place any limitation on the amount of indebtedness that the General Partner may cause the Partnership to incur, and holders of common units will have no right to control or influence the amount of indebtedness the Partnership incurs. High levels of indebtedness may have adverse consequences for the Partnership, including:

- Cash that would otherwise be available for distribution or to invest in the Partnership's business will be used to pay interest on indebtedness;
- Covenants in the indebtedness may restrict the Partnership's ability to conduct its business, to make acquisitions or develop its assets and to make distributions; and
- Default in the repayment of indebtedness could result in foreclosure on the Partnership's assets, or require the Partnership to refinance indebtedness at higher costs.

Your common units may be diluted.

The equity interests of investors in the Partnership may be diluted. The investors in the Partnership will indirectly benefit from the Partnership's production revenues from all of its wells in proportion to your respective number of common units, based on the original purchase price of common units issued in the offering regardless of:

- when you subscribe;
- which properties are acquired with your subscription proceeds; or
- the actual subscription price you paid for your common units as described below.

The Partnership Agreement restricts the remedies available to holders of the Partnership's common units for actions taken by the General Partner that might otherwise constitute breaches of fiduciary duty.

The Partnership Agreement contains provisions that reduce or eliminate the fiduciary and other duties that the General Partner, its officers and the other persons who control it might have otherwise owed to the Partnership and the holders of the Partnership's common units. In taking any action or making any decision on behalf of the General Partner or the Partnership, such persons will be presumed to have acted in good faith and, in any proceeding brought by or on behalf of any holder of common units or the Partnership, the person bringing such proceeding will have the burden of overcoming such presumption.

Furthermore, under the Partnership Agreement, the General Partner, its board of directors (and any committee thereof), its affiliates and the directors, officers and other persons who control the General Partner or any of its affiliates will not be liable for monetary damages to the Partnership or its limited partners for any acts or omissions unless there has been a final and non-appealable judgment entered by a court of competent jurisdiction determining that such person acted in bad faith or engaged in fraud or willful misconduct, or, in the case of a criminal matter, acted with knowledge that the conduct was criminal.

By purchasing a common unit, a common unit holder will become bound by the provisions in the Partnership Agreement, including the provisions discussed above.

Holders of the Partnership's common units have limited voting rights and are not entitled to elect or remove the General Partner or the board of directors of the General Partner.

Unlike the holders of common stock in a corporation, common unitholders have only limited voting rights on matters affecting the Partnership's business and, therefore, limited ability to influence management's decisions regarding the Partnership's business. Common unitholders will not elect the General Partner, or the members of its board of directors, and will have no right to remove the General Partner, or its board of directors. The Board of Directors of the General Partner is chosen by the owners of the General Partner.

Your liability may not be limited if a court finds that common unitholder action constitutes control of the Partnership's business.

A general partner of a partnership generally has unlimited liability for the obligations of the partnership, except for those contractual obligations of the partnership that are expressly made without recourse to the general partner. The Partnership is organized under Delaware law and it plans to conduct business in a number of other states. The limitations on the liability of holders of limited partner interests for the obligations of a limited partnership have not been clearly established in some of the other states in which the Partnership may do business. You could be liable for any and all of the Partnership's obligations as if you were a general partner if:

- a court or government agency determined that the Partnership were conducting business in a state but had not complied with that particular state's partnership statute; or
- your right to act with other common unitholders to approve some amendments to the Partnership Agreement or to take other actions under the Partnership Agreement constitutes "control" of the Partnership's business.

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

Under certain circumstances, common unitholders may have to repay amounts wrongfully returned or distributed to them. Under Section 17–607 of the Delaware Revised Uniform Limited Partnership Act, the Partnership may not make a distribution to you if the distribution would cause its liabilities to exceed the fair value of its assets. Delaware law provides that for a period of three years from the date of the impermissible distribution, limited partners who received the distribution and who knew at the time of the distribution that it violated Delaware law will be liable to the limited partnership for the distribution amount. Substituted limited partners are liable for the obligations of the assignor to make contributions to a partnership that are known to the substituted limited partner at the time it became a limited partner and for unknown obligations if the liabilities could be determined from the Partnership Agreement. Liabilities to partners on account of their partnership interest and liabilities that are non–recourse to the partnership are not counted for purposes of determining whether a distribution is permitted.

Fees and cost reimbursements that must be paid to the General Partner and the Managing Dealer regardless of success of the Partnership's activities will reduce the cash the Partnership has available for distribution.

The General Partner and its affiliates will receive reimbursement of third-party costs incurred in connection with the formation of the Partnership and the Partnership's business activities and will be reimbursed for general and administrative costs of the General Partner allocable to the Partnership, regardless of the Partnership's success in acquiring, developing and operating properties. In addition, the General Partner will receive an annual management fee, paid quarterly, of 0.5% of total gross equity proceeds raised in this offering. The Managing Dealer will receive sales commissions, marketing fees, the dealer manager incentive fees and account maintenance fees in connection with the offering. The fees and direct costs to be paid to the General Partner and the Managing Dealer will reduce the amount of cash distributions to investors.

Common units may be purchased by individuals who have an interest in the offering different from yours.

The owners of the General Partner have each purchased 5,000 common units for $20.00 per unit. In addition, the Partnership Agreement does not restrict the ability of any service providers or vendors to the Partnership from purchasing common units. In addition, if a matter were to be submitted to a vote of holders of common units, the owners of the General Partner or other service providers or vendors who purchase common units may have different interests from other holders of common units in voting their common units.

Risks Related to the Partnership's Business and the Oil and Natural Gas Industry

The Partnership may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements and management fees to the General Partner, to enable the Partnership to make cash distributions to holders of its common units under its cash distribution policy.

The Partnership may not have sufficient available cash each month to enable it to make cash distributions to the holders of common units. The amount of cash the Partnership can distribute on its common units principally depends upon the amount of cash the Partnership generates from its operations, which will fluctuate from month to month based on, among other things:

- that the Partnership's strategy of acquiring primarily non-operated oil and gas properties at attractive prices may not be successful or even if the Partnership successfully acquires properties, operations on such properties may not be successful;
- the amount of oil, natural gas and natural gas liquids the Partnership produces;
- the prices at which the Partnership sells its production;
- the Partnership's ability to acquire oil and natural gas properties at economically attractive prices;
- the Partnership's ability to hedge commodity prices at economically attractive prices;
- the level of the Partnership's capital expenditures, including its costs to participate in wells;
- the level of the Partnership's operating and administrative costs including fees and reimbursement to the General Partner; and
- the level of the Partnership's interest expense, which depends on the amount of its indebtedness and the interest payable thereon.

In addition, the actual amount of cash the Partnership will have available for distribution will depend on other factors, some of which are beyond the Partnership’s control, including:

- the amount of cash reserves established by the General Partner for the proper conduct of the Partnership’s business and for capital expenditures, which may be substantial;
- the operator(s) of the properties that the Partnership acquires will control the timing of any capital expenditures necessary to drill or overhaul any wells on the properties the Partnership invests in;
- the cost of acquisitions, operations, infrastructure and drilling;
- the Partnership’s debt service requirements and other liabilities;
- fluctuations in the Partnership’s working capital needs;
- the Partnership’s ability to borrow funds;
- the timing and collectability of receivables; and
- prevailing economic conditions.

As a result of these factors, the amount of cash the Partnership distributes to holders of its common units may fluctuate significantly from month to month.

If oil, natural gas or other hydrocarbon prices decrease and remain depressed for a prolonged period, cash flows from operations will decline and the Partnership may have to lower its distributions or may not be able to pay distributions at all.

The Partnership’s revenue, profitability and cash flow depend upon the prices for oil, natural gas and other hydrocarbons. The prices the Partnership will receive for its production will be volatile and a drop in prices can significantly affect its financial results and adversely affect the Partnership’s ability to obtain credit, maintain its borrowing capacity and to repay indebtedness, all of which can affect the Partnership’s ability to pay distributions. Changes in prices have a significant impact on the value of the Partnership’s reserves and on its cash flows.

Historically, world-wide oil and natural gas prices and markets have been subject to significant change, and may continue to be in the future. Oil prices fluctuated during 2016, with the monthly average price per barrel ranging from a low of $30.32 in February 2016 to a high of $51.97 in December 2016 (based on daily settlements of monthly contracts traded on the NYMEX). In 2017, monthly average oil prices ranged from a low of $45.18 per barrel in June 2017 to a two-year high of $57.88 in December 2017. Similarly, over the two year period from January 1, 2016 to December 31, 2017, natural gas prices have fluctuated from a low of $1.73 per MMBtu in March 2016 to $3.59 per MMBtu in December 2016. The monthly average natural gas price for December 2017 was $2.81 per MMBtu.

Continued fluctuations in oil and natural gas prices, price declines or any other unfavorable market condition could have a material adverse effect on the Partnership’s financial condition. Prices may fluctuate widely in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors that are beyond the Partnership’s control, such as:

- the domestic and foreign supply of and demand for oil and natural gas;
- the price and quantity of foreign imports of oil and natural gas;
- recent changes in federal regulations removing decades-old prohibition of the export of crude oil production in the U.S.;
- federal regulations applicable to exports of liquefied natural gas (“LNG”), including the commencement in 2016 of exports of LNG liquefied from natural gas produced in the lower 48 states of the U.S.;
- the level of consumer product demand;
- weather conditions;
- domestic and foreign governmental regulations, including environmental initiatives and taxation;
- overall domestic and global economic conditions;
- the value of the U.S. dollar relative to the currencies of other countries;
- political and economic conditions and events in foreign oil and natural gas producing countries, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, conditions in South America, Central America, China and Russia, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the proximity and capacity of natural gas pipelines and other transportation facilities to the Partnership’s production;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- the impact of energy conservation efforts.

Decreased oil, natural gas and other hydrocarbon prices will decrease Partnership revenues, and may also reduce the amount of oil, natural gas or other hydrocarbons that the Partnership can economically produce. If decreases occur, or if estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require the Partnership to write down, as a non–cash charge to earnings, the carrying value of its oil and natural gas properties for impairments. The Partnership is required to perform impairment tests on its assets whenever events or changes in circumstances lead to a reduction of the estimated useful life or estimated future cash flows that would indicate that the carrying amount may not be recoverable or whenever management's plans change with respect to those assets. The Partnership may incur impairment charges in the future, which could have a material adverse effect on its results of operations in the period taken and the Partnership's ability to borrow funds under a credit facility, which may adversely affect the Partnership's ability to make cash distributions to holders of its common units and service its debt obligations.

The Partnership will need additional funding post-closing of recently acquired assets in order to retain its full interest therein.

In addition to the $87.5 million purchase price for the assets acquired by the Partnership on February 1, 2018 and the associated debt incurred to complete the acquisition, the Partnership anticipates that it may be obligated to invest an additional $65 to $70 million in drilling and well completion capital expenditures from February 1, 2018 through 2023 to fully participate in operator drilling programs in the Bakken Assets without becoming subject to non-consent penalties under the joint operating agreements governing those properties. The Partnership will depend, at least in part, on continued sales pursuant to the terms of its ongoing public offering and may require refinancing of its existing debt and/or additional financing to repay existing debt and to fund the anticipated capital expenditures needed to retain its full interest in these assets. None of these funding sources is guaranteed, and if the Partnership is unable to obtain all of this funding the Partnership may lose all or a portion of the assets acquired, and its results of operations will be negatively affected accordingly.

If the Partnership is unable to find suitable prospects and properties, the Partnership may not be able to achieve its investment objectives or pay distributions.

The Partnership's ability to achieve its investment objectives and to pay distributions depends primarily upon its ability to acquire and develop oil and gas properties. Competition may reduce the number of suitable investment opportunities offered to the Partnership or increase the bargaining power of property owners seeking to sell. Additionally, disruptions in the credit markets have materially impacted the cost and availability of debt to finance oil and gas acquisitions in the past. A period in which there is a lack of available debt could result in a reduction of suitable investment opportunities and create a competitive advantage to other entities that have greater financial resources than the Partnership does. During such times, the Partnership's ability to borrow monies to finance the purchase of, or other activities related to, oil and gas assets will be negatively impacted. If the Partnership acquires properties and other investments at higher prices or by using less-than-ideal capital structures, the Partnership's returns will be lower and the value of its assets may decrease significantly below the amount it paid for the assets.

Also, the more common units the Partnership sells in this offering, the greater the challenge will be to invest all of the net offering proceeds on attractive terms. The Partnership can give no assurance that it will be successful in identifying or acquiring suitable properties on financially attractive terms or that its objectives will be achieved. If the Partnership is unable to identify and acquire suitable properties promptly, it will hold the proceeds from this offering in an interest-bearing account or invest the proceeds in short-term assets. If the Partnership continues to be unsuccessful in identifying and acquiring suitable properties, the Partnership may ultimately decide to liquidate. In the event the Partnership is unable to timely locate suitable properties, it may be unable or limited in its ability to pay distributions and the Partnership may not be able to meet its investment objectives.

The Partnership will have limited control over the activities on properties its does not operate.

Twelve other companies operate the properties the Partnership has acquired. The Partnership will have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that it is required to fund with respect to them. The failure of an operator of the Partnership's wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in the Partnership's best interest could reduce the Partnership's production and revenues. The Partnership's dependence on the operator and other working interest owners for these projects and its limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of the Partnership's targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

The Partnership expects to participate in oil and gas leases with third parties who may not be able to fulfill their commitments to the Partnership's projects.

The Partnership expects to own less than 100% of the working interest in the oil and gas properties it acquires, and other parties will own the remaining portion of the working interests. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. The Partnership could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. Another working interest owner may be unable or unwilling to pay its share of project costs, and, in some cases, may declare bankruptcy. In the event any of the Partnership's co-owners do not pay their share of such costs, the Partnership would likely have to pay its share of those costs, and the Partnership may be unsuccessful in any efforts to recover these costs from its partners, which could materially adversely affect the Partnership's financial position.

The Partnership may experience delays in locating oil and gas properties to acquire, which could limit its ability to make distributions and lower the overall return on your investment.

The Partnership will rely on the General Partner and independent oil and gas professionals to identify suitable investments. To the extent that the General Partner and the independent oil and gas professionals employed by the General Partner face competing demands on their time at times when the Partnership has capital ready for investment, the Partnership may face delays in locating suitable properties. Further, the more money the Partnership raises in its ongoing public offering, the more difficult it will be to invest the net offering proceeds promptly and on attractive terms. Therefore, the size of the public offering and the continuing high demand for the types of oil and gas properties the Partnership desires to purchase increase the risk of delays in investing its net offering proceeds. Delays the Partnership encounters in the selection and acquisition or origination of income-producing properties would likely limit its ability to pay distributions to holders of its common units and lower their overall returns. Further, the oil and gas development activities on a non-producing property will typically take months or longer to complete. Therefore, holders of the Partnership's common units could experience delays in receiving the cash distributions attributable to those particular properties.

Because the Partnership will depend on the General Partner and its affiliates to conduct the Partnership's operations, any adverse changes in the financial health of the General Partner could hinder the Partnership's operating performance and ability to make distributions.

The Partnership will depend on the General Partner and its affiliates and other third party operators for the acquisition, development and operation of the Partnership's properties. The General Partner has been recently formed and has limited operating history. Any adverse changes in the financial condition of the General Partner or in the Partnership's relationship with the General Partner or its officers and employees could hinder its or their ability to successfully manage the Partnership's operations.

Property interests that the Partnership buys or of which the Partnership participates in the development may not produce as projected and the Partnership may be unable to determine reserve potential, identify liabilities associated with the properties or obtain protection from sellers against such liabilities, which could adversely affect the Partnership's cash available for distribution.

Any acquisition or decision to participate in the development of a property the Partnership has acquired will require an assessment of recoverable reserves, title, future oil, natural gas and natural gas liquids prices, operating costs, potential environmental hazards, potential tax and ERISA liabilities, and other liabilities and similar factors. Reserve estimates may be prepared by the operators or third parties for the operators of properties. The Partnership may engage its own third-party petroleum engineers to review such reserve estimate reports and provide the Partnership with an independent assessment of the reserve estimates. The process of estimating oil and gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors such as future oil and gas prices, drilling and operating expenses, capital expenditures, taxes and the availability of funds, all of which can be difficult to predict with accuracy. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. The Partnership expects that its review efforts will be focused on the higher valued properties in its acquisitions and will be inherently incomplete because it generally is not feasible to review in depth every individual property involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal existing or potential problems, nor will it permit the Partnership to become sufficiently familiar with the properties to assess fully their deficiencies and potential. Inspections may not always be performed on every well, and potential problems, such as ground water contamination and other environmental conditions and deficiencies in the mechanical integrity of equipment are not necessarily observable even when an inspection is undertaken. Any unidentified problems could result in material liabilities and costs that negatively impact the Partnership's financial conditions and results of operations and its ability to make cash distributions to holders of its common units and service its debt obligations.

Additional potential risks related to acquisition and development include, among other things:

- incorrect assumptions regarding the future prices of oil, natural gas and other hydrocarbons or the future operating or development costs of properties acquired;
- incorrect estimates of the reserves and projected development results attributable to a property the Partnership acquires;
- drilling, operating and other cost overruns by the operator of the properties;
- an inability to integrate successfully the properties the Partnership acquires;
- the assumption of liabilities; and
- limitations on rights to indemnity from the seller.

Deficiencies of title to the Partnership's leased interests could significantly affect its financial condition.

If an examination of the title history of a property reveals that an oil or natural gas lease or other developed rights has been purchased in error from a person who is not the owner of the mineral interest desired, the Partnership's interest would substantially decline in value. In such cases, the amount paid for such oil or natural gas lease or leases or other developed rights would be lost. It is management's expectation that in acquiring property interest in oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights, it will not incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, the Partnership will rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling an oil or natural gas well, however, it is the normal practice in the oil and natural gas industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed oil or natural gas well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, such as obtaining affidavits of heirship or causing an estate to be administered. Such curative work entails expense, and it may happen, from time to time, that the operator may elect to proceed with a well despite defects to the title identified in the preliminary title opinion. the Partnership's failure to obtain perfect title to its leaseholds may adversely impact its ability in the future to increase production and reserves.

The operator of the properties the Partnership acquires may engage in exploration activities on these properties which activities are more risky than development activities.

The Partnership expects to acquire interests in oil and gas properties which require additional drilling and other exploration activities to fully develop. Some of the drilling on its properties may be classified as exploration drilling. Exploration drilling is inherently more risky than development drilling. Although the Partnership expects that any exploration drilling will generally be located near areas which have undergone successful drilling or in areas with geological characteristics similar to areas which have been successfully developed, no assurances can be made that the exploration or development drilling will be successful in discovering producible oil and gas reserves.

The General Partner may cause the Partnership not to participate with the operator in the drilling of wells on the Partnership's properties.

If the Partnership has the opportunity to participate in wells, the General Partner may decide to sell or farmout the well. Also, if a well is proposed under an operating agreement for one of the properties the Partnership owns, the General Partner may cause the Partnership to "non-consent" the well under the applicable operating agreement. Non-consenting a well will generally cause the Partnership not to be obligated to pay the costs of the well, but the Partnership will not be entitled to the proceeds of production from the well until a penalty is received by the parties that drilled the well. If the General Partner makes the decision to sell, farmout or non-consent a well or other development activity, the Partnership Agreement provides that the General Partner will have no liability to the Partnership so long as the decision is made in good faith.

The Partnership could experience periods of higher costs if oil and natural gas prices rise or as drilling activity otherwise increases in the Partnership's area of operations. Higher costs could reduce the Partnership's profitability and cash flow.

Historically, capital and operating costs typically rise during periods of sustained increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond the Partnership's control as drilling activity increases, such as increases in the cost of electricity, tubular goods, water, sand and other disposable materials used in fracture stimulation and other raw materials that the Partnership and its vendors will rely upon, and the cost of services and labor especially those required in horizontal drilling and completion. Historically, oil and natural gas prices have fluctuated resulting in fluctuating levels of drilling activity in the U.S. oil and natural gas industry. Lower prices typically lead to lower costs of some drilling and completion equipment, services, materials and supplies. As commodity prices rise or stabilize or drilling activity otherwise increases, these lower cost levels may not be sustainable over long periods. As a result, such costs may rise faster than selling prices thereby negatively impacting the Partnership's profitability, cash flow and causing it to possibly reconfigure or reduce its drilling program.

Federal and state legislative initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays, and even could result in the Partnership ceasing business operations.

Hydraulic fracturing is used to stimulate production of hydrocarbons, particularly natural gas, from dense rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The operators of the properties the Partnership acquires will routinely use hydraulic fracturing techniques in most drilling and completion programs. In past legislative sessions, legislation was introduced before Congress to provide for federal regulation of hydraulic fracturing using materials other than diesel under the Safe Drinking Water Act and to require disclosure of the chemicals used in the fracturing process; this legislation has not passed. At the state and local levels, some jurisdictions have adopted, and others are considering adopting, requirements that could impose more stringent permitting, public disclosure of fracturing chemicals or well construction requirements on hydraulic fracturing activities, as well as bans on hydraulic fracturing activities. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where the Partnership acquires producing properties, the Partnership could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from participating in drilling wells. More widespread or prolonged moratoriums or prohibitions of hydraulic fracturing could, depending on the makeup of the Partnership's assets, cause the Partnership to cease business operations.

The Environmental Protection Agency's ("EPA") enforcement initiative could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing, impact the Partnership's ability to conduct business, and increase the Partnership's costs of compliance and doing business.

Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel. The EPA has announced an initiative under the Toxic Substance Control Act to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals. The EPA also issued a pretreatment standard for the discharge of wastewater resulting from hydraulic fracturing activities, prohibiting the discharges of wastewater pollutants from onshore unconventional oil and gas extraction to publicly owned treatment works. The EPA has released a draft of a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. In December 2016, the EPA released its final report "Hydraulic Fracturing for Oil and Gas: Impacts from the Hydraulic Fracturing Water Cycle on Drinking Water Resources in the United States." This report concludes that hydraulic fracturing can impact drinking water resources in certain circumstances but also noted that certain data gaps and uncertainties limited the EPA's assessment. The EPA has identified environmental compliance by the energy extraction sector to be one of its enforcement initiatives for 2017 to 2019, although it is unclear about the outlook for this initiative with the current administration. Even if regulatory burdens temporarily ease, the historic trend of more expansive and stricter environmental regulation may continue for the long term. Any additional regulatory actions taken by the EPA could increase the costs of the Partnership's operations or result in additional operating restrictions or delays. Restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that the Partnership ultimately is able to produce.

The Partnership's hedging transactions will expose it to counterparty credit risk.

The Partnership expects to engage in hedging transactions to reduce, but not eliminate, the effect of volatility in oil, gas and other hydrocarbon prices. The Partnership's hedging transactions expose the Partnership to risk of financial loss if a counterparty fails to perform under a derivative contract. The risk of counterparty non-performance is of particular concern when there are disruptions in the financial markets and there are significant declines in oil and natural gas prices. Either of these events could lead to sudden changes in a counterparty's liquidity and impair its ability to perform under the terms of the derivative contract. The Partnership is unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if the Partnership does accurately predict sudden changes, the Partnership's ability to negate the risk may be limited depending upon market conditions. Furthermore, the bankruptcy of one or more of the Partnership's hedge providers or some other similar proceeding or liquidity constraint might make it unlikely that the Partnership would be able to collect all or a significant portion of amounts owed to it by the distressed entity or entities.

During periods of falling commodity prices the Partnership's hedge receivable positions increase, which increases the Partnership's exposure. If the creditworthiness of the Partnership's counterparties deteriorates and results in their nonperformance, the Partnership could incur a significant loss.

The Partnership's hedging activities could result in financial losses or could reduce the Partnership's net income, which may adversely affect the Partnership's ability to pay cash distributions to holders of its common units.

To achieve more predictable cash flows and to reduce the Partnership's exposure to fluctuations in the prices of oil, natural gas and other hydrocarbons, the Partnership may enter into hedging arrangements for a significant portion of its estimated future production. If the Partnership experiences a sustained material interruption in its production, the Partnership might be forced to satisfy all or a portion of its hedging obligations without the benefit of the cash flows from the Partnership's sale of the underlying physical commodity, resulting in a substantial diminution of its liquidity.

The Partnership's ability to use hedging transactions to protect it from future price declines will be dependent upon oil and natural gas prices at the time the Partnership enters into future hedging transactions and the Partnership's future levels of hedging, and as a result its future net cash flows may be more sensitive to commodity price changes. Additionally, it may not be possible or economic to hedge all of the hydrocarbons the Partnership produces because of the lack of a market for such hedges or other reasons. The Partnership may hedge certain hydrocarbons it produces by entering into swaps, collars or other contracts covering hydrocarbons the Partnership considers to be priced similarly to the hydrocarbons it produces, and could be subject to losses if the prices for the hydrocarbons the Partnership produces do not match the hydrocarbons the Partnership contracts for.

The Partnership's policy will be to hedge a portion of its near–term estimated production. The prices at which the Partnership hedges its production in the future will be dependent upon commodity prices at the time the Partnership enters into these transactions, which may be substantially higher or lower than current oil, natural gas and other hydrocarbon prices. Accordingly, the Partnership's price hedging strategy may not protect it from significant declines in oil and natural gas prices received for its future production. Conversely, the Partnership's hedging strategy may limit its ability to realize cash flows from commodity price increases. It is also possible that a substantially larger percentage of the Partnership's future production will not be hedged as compared with the next few years, which would result in its oil, natural gas and natural gas liquids revenues becoming more sensitive to commodity price changes. The General Partner will not be liable for any losses the Partnership incurs as a result of the Partnership's hedging policy or the implementation of that policy.

The adoption of derivatives legislation and regulations related to derivative contracts could have an adverse impact on the Partnership's ability to hedge risks associated with its business.

Title VII of the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act") establishes federal oversight and regulation of over-the-counter ("OTC") derivatives and requires the Commodity Futures Trading Commission (the "CFTC") and the SEC to enact further regulations affecting derivative contracts, including the derivative contracts the Partnership uses to hedge its exposure to price volatility through the OTC market. Although the CFTC and the SEC have issued final regulations in certain areas, final rules in other areas and the scope of relevant definitions and/or exemptions still remain to be finalized.

In one of its rulemaking proceedings still pending under the Dodd-Frank Act, the CFTC issued on November 7, 2013, a proposed rule imposing position limits for certain futures and option contracts in various commodities (including natural gas) and for swaps that are their economic equivalents. Under the proposed rules on position limits, certain types of hedging transactions are exempt from these limits on the size of positions that may be held, provided that such hedging transactions satisfy the CFTC's requirements for certain enumerated "bona fide hedging" transactions or positions. On May 27, 2016, the CFTC issued a proposed supplement to its 2013 position limits proposal, which is intended to modify the process by which a non-enumerated hedging transaction may be determined to be a "bona fide hedge" transaction, and thereby become exempt from the CFTC's position limits. A final rule has not yet been issued. Similarly, the CFTC has issued a proposed rule regarding the capital a swap dealer or major swap participant is required to set aside with respect to its swap business, but the CFTC has not yet issued a final rule.

The CFTC issued a final rule on margin requirements for uncleared swap transactions on January 6, 2016, which includes an exemption from any requirement to post margin to secure uncleared swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. In addition, the CFTC has issued a final rule authorizing an exemption from the otherwise applicable mandatory obligation under the Dodd-Frank Act to clear all swap transactions through a derivatives clearing organization and to trade all such swaps on a regulated exchange, which exemption applies to swap transactions entered into by commercial end-users in order to hedge commercial risks affecting their business. The Dodd-Frank Act also imposes recordkeeping and reporting obligations on counterparties to swap transactions and other regulatory compliance obligations.

All of the above regulations could increase the costs to the Partnership of entering into financial derivative transactions to hedge or mitigate its exposure to commodity price volatility and other commercial risks affecting its business. While it is not possible at this time to predict when the CFTC will issue final rules applicable to position limits or capital requirements, depending on the Partnership's ability to satisfy the CFTC's requirements for a commercial end-user using swaps to hedge or mitigate its commercial risks, these rules and regulations may require the Partnership to comply with position limits and with certain clearing and trade-execution requirements in connection with the Partnership's financial derivative activities. When a final rule on capital requirements for swap dealers is issued, the Dodd-Frank Act may require the Partnership's current swap dealer counterparties to post additional capital as a result of entering into uncleared financial derivatives with the Partnership, which capital requirements rule could increase the costs to the Partnership of future financial derivatives transactions. The Volcker Rule provisions of the Dodd-Frank Act may also require the Partnership's current bank counterparties that engage in financial derivative transactions to spin off some of their derivatives activities to separate entities, which separate entities may not be as creditworthy as the current bank counterparties. Under such rules, other bank counterparties may cease their current business as hedge providers. These changes could reduce the liquidity of the financial derivatives markets thereby reducing the ability of entities like the Partnership, as commercial end-users, to have access to financial derivatives to hedge or mitigate the Partnership's exposure to commodity price volatility.

As a result, the Dodd-Frank Act and any new regulations issued thereunder could significantly increase the cost of derivative contracts (including through requirements to post cash collateral), which could adversely affect the Partnership's capital available for other commercial operations purposes, materially alter the terms of future swaps relative to the terms of the Partnership's existing bilaterally negotiated financial derivative contracts, and reduce the availability of derivatives to protect against commercial risks the Partnership encounters.

If the Partnership reduces its use of derivative contracts as a result of the new requirements, the Partnership's results of operations may become more volatile and cash flows less predictable, which could adversely affect its ability to plan for and fund capital expenditures. Finally, the legislation was intended, in part, to reduce the volatility of oil, natural gas and natural gas liquids prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil, natural gas and natural gas liquids. The Partnership's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on the Partnership's financial condition, results of operations, or cash flows.

The distressed financial conditions of any hydrocarbon purchasers the Partnership does business with could have an adverse impact on us in the event these purchasers are unable to pay for the Partnership's share of oil and gas production.

Some of the Partnership's hydrocarbon purchasers may experience severe financial problems that may have a significant impact on their creditworthiness. The Partnership cannot provide assurance that one or more of its financially distressed hydrocarbon purchasers will not default on their obligations to the Partnership or that such a default or defaults will not have a material adverse effect on the Partnership's business, financial position, future results of operations or future cash flows. Furthermore, the bankruptcy of one or more of the Partnership's hydrocarbon purchasers, or some other similar proceeding or liquidity constraint, might make it unlikely that the Partnership would be able to collect all or a significant portion of amounts owed by the distressed entity or entities. In addition, such events might force such purchasers to reduce or curtail their future purchase of the Partnership's production and services, which could have a material adverse effect on the Partnership's results of operations and financial condition.

The Partnership may not realize all the anticipated benefits of, any acquisitions that it makes.

Acquisitions involve numerous risks, including:

- operating a significantly larger combined organization;
- the risk that reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the diversion of management attention of the General Partner from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever acquisitions are consummated, and the Partnership may experience unanticipated delays in realizing the benefits of an acquisition.

The properties the Partnership acquires will require drilling and well completion to fully develop their potential. If drilling and well completion are unsuccessful, the Partnership's cash available for distributions and financial condition will be adversely affected.

The Partnership has acquired and plans to acquire oil and gas properties that are not fully developed, and require that the Partnership engages in drilling and well completion to fully exploit the reserves attributable to the properties. Because the Partnership has acquired and intends to acquire non-operated properties, it will not be in charge of the drilling and well completions, but will be obligated to pay its pro rata share of drilling and completion costs or be subject to penalties. Drilling will involve numerous risks, including the risk that the Partnership will not encounter commercially productive oil or natural gas reservoirs. The Partnership may incur significant expenditures to drill and complete wells, including cost overruns. Additionally, current geoscience technology may not allow the Partnership to know conclusively, prior to drilling a well, that oil or natural gas is present or economically producible. The costs of drilling and completing wells are often uncertain, and it is possible that the Partnership will make substantial expenditures on drilling and not discover reserves in commercially viable quantities. These expenditures will reduce cash available for distribution to holders of the Partnership's common units and for servicing the Partnership's debt obligations.

Drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors, including:

- unexpected drilling or operating conditions;
- facility or equipment failure or accidents;
- shortages or delays in the availability of drilling rigs and equipment and in hiring qualified personnel;
- adverse weather conditions;
- shortages of water required for hydraulic fracturing or other operations;
- compliance with environmental and governmental requirements;
- reductions in oil or gas prices;
- proximity to and capacity of transportation and processing facilities;
- title problems;
- encountering abnormal pressures or unusual, unexpected or irregular geological formations;
- pipeline ruptures;
- fires, blowouts, craterings and explosions; and
- uncontrollable flows of oil or natural gas or well fluids.

Even if drilled, completed wells may not produce quantities of oil or natural gas that are economically viable or that meet earlier estimates of economically recoverable reserves. A productive well may become uneconomic if water or other deleterious substances are encountered, which impair or prevent the production of oil and/or natural gas from the well. Overall drilling success rates or drilling success rate for activity within a particular project area may decline. Unsuccessful drilling activities could result in a significant decline in the Partnership's production and revenues and materially harm the Partnership's operations and financial condition by reducing its available cash and resources.

The Partnership must find or acquire economically recoverable reserves to sustain production and future cash flows. If the Partnership is unable to find or acquire reserves, its future financial condition will be adversely affected.

The Partnership's continued success depends upon its ability to find, develop and acquire oil and gas reserves that are economically recoverable. If the Partnership does not participate in the drilling of suitable prospects, you are unlikely to realize your investment expectations.

In addition, the Partnership's future oil and natural gas production will depend on its success in finding or acquiring additional reserves. If the Partnership is unable to replace reserves through drilling or acquisitions, the Partnership's level of production and cash flows will be adversely affected. In general, production from oil and natural gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. The Partnership's total proved reserves decline as reserves are produced unless the Partnership conducts other successful acquisition and development activities. The Partnership's ability to make the necessary capital investment to maintain or expand its asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. The Partnership may not be successful in developing or acquiring additional reserves.

The Partnership's producing properties are located and may be located in a limited geographic area, making the Partnership vulnerable to risks associated with having geographically concentrated operations.

Depending upon the amount of funds the Partnership raises and the number of properties the Partnership acquires, the Partnership's producing properties may geographically concentrated. Because of this concentration and possible concentration, the success and profitability of the Partnership's operations may be disproportionately exposed to regional factors relative to its competitors that have more geographically dispersed operations. The Partnership's Bakken Assets are all located in northwestern North Dakota. These factors include, among others: (i) the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and rail transportation capacity constraints; (ii) the availability of rigs, equipment, oil field services, supplies, and labor; (iii) the availability of processing and refining facilities; and (iv) infrastructure capacity. In addition, the Partnership's operations may be adversely affected by severe weather events such as floods, ice storms and tornadoes, which can intensify competition for the items described above during months when drilling is possible and may result in periodic shortages. The possible concentration of the Partnership's operations in a limited geographic area also increases the Partnership's exposure to changes in local laws and regulations, certain lease stipulations designed to protect wildlife, and unexpected events that may occur in the regions such as natural disasters, seismic events, industrial accidents or labor difficulties. Any one of these events has the potential to cause producing wells to be shut-in, delay operations, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. Any of the risks described above could have a material adverse effect on the Partnership's financial condition, results of operations and cash flows.

The Partnership may be unable to compete effectively with larger companies, which may adversely affect its ability to generate sufficient revenue and its ability to pay distributions to holders of its common units and service its debt obligations.

The oil and natural gas industry is intensely competitive, and the Partnership competes with other companies that have greater resources than the Partnership. The Partnership's ability to acquire properties in the future will be dependent upon its ability to evaluate and select suitable properties to consummate transactions in a highly competitive market. Many of the Partnership's larger competitors not only acquire properties, drill for and produce oil and natural gas, but also engage in refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties, and evaluate, bid for and purchase a greater number of properties than the Partnership's financial or human resources permit. In addition, these companies may have a greater ability to continue drilling activities during periods of low commodity prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition has been strong in hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. The Partnership's inability to compete effectively with larger companies could have a material adverse impact on its business activities, financial condition and results of operations.

The Partnership's business is subject to operational risks that will not be fully insured, which, if they were to occur, could adversely affect the Partnership's financial condition or results of operations and, as a result, the Partnership's ability to pay distributions to holders of its common units and service its debt obligations.

The Partnership's business activities are subject to operational risks, including:

- damages to equipment caused by natural disasters such as earthquakes, adverse weather conditions, including tornadoes, hurricanes, drought and flooding;
- unexpected formations and pressures;
- facility or equipment malfunctions;
- pipeline ruptures or spills;
- fires, blowouts, craterings and explosions;
- release of toxic gasses;
- uncontrollable flows of oil or natural gas or well fluids; and
- surface fluid spills, saltwater contamination, and surface or ground water contamination from petroleum constituents or hydraulic fracturing chemical additives.

Any of these events could adversely affect the Partnership's ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension cessation or of operations, and attorneys' fees and other expenses incurred in the prosecution or defense of litigation and could also result in requirements to remediate, regulatory investigations, and/or the interruption of the Partnership's business and/or the business of third parties.

As is customary in the industry, the operator of the properties will maintain insurance against some but not all of these risks. The Partnership may elect not to obtain insurance if it believes that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on the Partnership's business activities, financial condition, results of operations and ability to pay distributions to holders of its common units and service its debt obligations.

Compliance with environmental and other federal, state and local governmental laws and regulations, as well as liability arising from the release of hazardous substances, is complex and could be costly and could negatively impact the costs, manner or feasibility of conducting the Partnership's operations.

The Partnership's business is subject to complex and stringent laws and regulations governing the acquisition, development, operation, production and marketing of oil and gas, taxation, safety matters and the discharge of materials into the environment. In order to conduct the Partnership's operations in compliance with these laws and regulations, the operator(s) of the Partnership's properties must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining and maintaining regulatory approvals or drilling permits could have a material adverse effect on development of the Partnership's properties, and receipt of drilling permits with onerous conditions could increase compliance costs. In addition, regulations regarding resource conservation practices and the protection of correlative rights affect operations on the Partnership's properties by limiting the quantity of oil, natural gas and natural gas liquids the Partnership may produce and sell.

The Partnership's operations will be subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil, natural gas and natural gas liquids. While the cost of compliance with these laws is not expected to be material to the Partnership's operations, the possibility exist that new laws, regulations or enforcement policies could be more stringent and significantly increase the Partnership's compliance costs. If the Partnership is not able to recover the resulting costs through insurance or increased revenues, the Partnership's ability to pay distributions to holders of the Partnership's common units and service the Partnership's debt obligations could be adversely affected.

The Partnership may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of its wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including, for example:

- the Clean Air Act, or the CAA, and comparable state laws and regulations that impose obligations related to emissions of air pollutants;
- the Clean Water Act and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated water;
- the Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from oil and gas facilities;
- the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned by us or at locations to which the Partnership has sent waste for disposal;
- the Safe Drinking Water Act and state or local laws and regulations related to underground injection (including hydraulic fracturing);
- the Endangered Species Act and comparable state and local laws and regulations which protect endangered and threatened species and the ecosystems on which they depend;
- the National Environmental Policy Act and comparable state statutes which ensure that environmental issues are adequately addressed in decisions involving major governmental actions (including the leasing of government land);
- the Toxic Substances Control Act and comparable state statutes which regulate the manufacture, use, distribution and disposal of chemical substances;
- the Oil Pollution Act, or OPA, which subjects responsible parties to liability for removal costs and damages arising from an oil spill in waters of the U.S.; and
- emergency planning and community right to know regulations under the Title III of CERCLA and similar state statutes require that the Partnership organizes and/or discloses information about hazardous materials used or produced in the Partnership's operations.

Under these laws and regulations, the Partnership could be liable for costs of investigation, removal and remediation, damages to and loss of use of natural resources, loss of profits or impairment of earning capacity, property damages, costs of increased public services, as well as administrative, civil and criminal fines and penalties and the issuance of orders enjoining future operations. Certain environmental statutes, including CERCLA, OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where hazardous substances or other waste products have been disposed of or otherwise released. More stringent laws and regulations, including any related to climate change and greenhouse gases, may be adopted in the future. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

Climate change legislation or regulations restricting emissions of greenhouse gases, or GHGs, could result in increased operating costs and reduced demand for the oil, natural gas and natural gas liquids the Partnership produces.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the Supreme Court struck down the permitting requirements, it upheld the EPA's authority to control GHG emissions when a permit is required due to emissions of other pollutants. These permitting provisions, to the extent applicable to our operations, could require the operator(s) of the Partnership's properties to implement emission controls or other measures to reduce GHG emissions and the Partnership could incur additional costs to satisfy those requirements. Further, the EPA has adopted rules to regulate methane emissions, including from new and modified oil and gas production sources and natural gas processing and transmission sources, and has announced its intention to regulate methane emissions from existing oil and gas sources. The EPA attempted to suspend enforcement of the methane rule, but this action as challenged on appeal and was ruled improper. The EPA is reported to be considering rulemaking to rescind or revise the rule.

In addition, the EPA requires the reporting of GHG emissions from specified large GHG emission sources including onshore and offshore oil and natural gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities, which may include facilities the Partnership owns. Reporting of GHG emissions from such facilities is required on an annual basis. Should the operator(s) of the Partnership's properties trigger the reporting requirement, the Partnership will incur costs associated with the reporting obligation.

In past legislative sessions, Congress considered legislation to reduce emissions of GHGs and many states and regions have adopted or have considered measures to reduce GHG emission reduction levels, often involving the planned development of GHG emission inventories and/or cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances. Federal efforts at a cap and trade program have not moved forward in Congress. The adoption and implementation of any legislation or regulatory programs imposing reporting obligations on, or limiting emissions of GHGs from, equipment and operations on the Partnership's properties could require the Partnership to incur costs to reduce emissions of GHGs associated with the Partnership's operations or could adversely affect demand for the oil, natural gas and natural gas liquids that the Partnership produces.

Significant physical effects of climatic change have the potential to damage the Partnership's facilities, disrupt the Partnership's production activities and cause the Partnership to incur significant costs in preparing for or responding to those effects.

In an interpretative guidance on climate change disclosures, the SEC indicates that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland, and water availability and quality. If such effects were to occur, the operations that the Partnership plans to engage in may be adversely affected. Potential adverse effects could include damages to the Partnership's facilities from powerful winds or rising waters in low lying areas, disruption of the Partnership's production activities either because of climate-related damages to the Partnership's facilities in the Partnership's costs of operation potentially arising from such climatic effects, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on the Partnership's financing and operations by disrupting the transportation or process related services provided by midstream companies, service companies or suppliers with whom the Partnership has a business relationship. The Partnership may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. Should drought conditions occur, the Partnership's ability to obtain water in sufficient quality and quantity could be impacted and in turn, the Partnership's ability to perform hydraulic fracturing operations could be restricted or made more costly.

The Partnership expects to be subject to regulation under New Source Performance Standards, or NSPS, and National Emissions Standards for Hazardous Air Pollutants, or NESHAP programs, which could result in increased operating costs.

On April 17, 2012, the EPA issued final rules that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and the NESHAP programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards required owners/operators to reduce volatile organic compound, or VOC, emissions from natural gas not sent to the gathering line during well completion either by flaring, using a completion combustion device, or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to newly fractured wells and also existing wells that are refractured. Further, the finalized regulations also established specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. The EPA has issued new rules limiting methane emissions from new or modified oil and gas sources. The rules amend the air emissions rules for the oil and natural gas sources and natural gas processing and transmission sources to include new standards for methane. The EPA attempted to suspend enforcement of the methane rule, but this action as challenged on appear and was ruled improper. The EPA is reported to be considering rulemaking to rescind or revise the rule. Simultaneously with the methane rules, the EPA adopted new rules governing the aggregating of multiple surface sites into a single-source of air quality permitting purposes. In addition, the EPA had announced plans to begin work on regulations to regulate methane emissions from existing oil and gas sources. These rules and any revised rules may require the installation of equipment to control emissions on producing properties the Partnership's acquires or could require the Partnership to obtain permits for such operations.

The Partnership and the operators of its properties may encounter obstacles to marketing the Partnership's share of oil, natural gas and other hydrocarbons, which could adversely impact the Partnership's revenues.

The marketability of the Partnership's production will depend upon numerous factors beyond the Partnership's control, including the availability and capacity of natural gas gathering systems, pipelines and other transportation and processing facilities that the Partnership expects to be owned by third parties. Transportation space on the gathering systems and pipelines the Partnership expects to utilize is occasionally limited or unavailable due to repairs or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. The Partnership's access to transportation and processing options and the marketing of the Partnership's production can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, as well as the other risks discussed above. The availability of markets are beyond the Partnership's control. If market factors dramatically change, the impact on the Partnership's revenues could be substantial and could adversely affect the Partnership's ability to produce and market oil, natural gas and natural gas liquids, the value of the Partnership's common units and the Partnership's ability to pay distributions on the Partnership's common units and service the Partnership's debt obligations.

The Partnership may be required to shut-in wells or delay initial production for lack of a viable market or because of the inadequacy or unavailability of pipeline, gathering system, processing, treating, fractionation or refining capacity. When that occurs, the Partnership will be unable to realize revenue from such wells until the inadequacy or unavailability is remedied. This can result in considerable delays from the initial discovery of a reservoir to the actual production of the oil and natural gas and realization of revenues.

Legislation or regulatory initiatives intended to address seismic activity could restrict the Partnership's ability to dispose of saltwater gathered from the Partnership's drilling and production activities, which could have a material adverse effect on the Partnership's business.

The properties that the Partnership has already or may acquire may require the Partnership to dispose of saltwater gathered from its operations pursuant to permits issued to the Partnership by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent permitting or operating constraints or new monitoring and reporting requirements owing to, among other things, concerns of the public or governmental authorities regarding such disposal activities.

One such concern relates to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities. When caused by human activity, such events are called induced seismicity. Developing research suggests that the link between seismic activity and wastewater disposal may vary by region, and that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. In March 2016, the United States Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico, and Arkansas. The United States Geological Survey also noted the potential for induced seismicity in Ohio and Alabama. In response to these concerns, regarding induced seismicity, regulators in some states have imposed, or are considering imposing, additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, Oklahoma issued new rules for wastewater disposal wells in 2014 that imposed certain permitting and operating restrictions and reporting requirements on disposal wells in proximity to faults and also, from time to time, developed and implemented plans directing certain wells where seismic incidents have occurred to restrict or suspend disposal well operations.

Also, ongoing lawsuits allege that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells. Increased regulation and attention given to induced seismicity could lead to greater opposition, including litigation, to oil and gas activities utilizing injection wells for waste disposal. Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where saltwater disposal activities occur or are proposed to be performed. Court decisions or the adoption of any new laws, regulations, or directives that restrict the Partnership’s ability to dispose of saltwater generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of saltwater disposed in such wells, restricting disposal well locations or otherwise, or by requiring the Partnership to shut down disposal wells, could significantly increase the Partnership’s costs to manage and dispose of this saltwater, which could have a material adverse effect on the Partnership’s financial condition and results of operations.

There are inherent limitations in all control systems, and misstatements due to error or fraud that could seriously harm the Partnership’s business may occur and not be detected.

The Partnership’s management, including the chief executive officer and chief financial officer, do not expect that the Partnership’s or the Partnership’s operators’ internal controls and disclosure controls will prevent all possible error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, an evaluation of controls can only provide reasonable assurance that all material control issues and instances of fraud, if any, in the Partnership have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. Further, controls can be circumvented by the individual acts of some persons or by collusion of two or more persons. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. A failure of the Partnership’s controls and procedures to detect error or fraud could seriously harm the Partnership’s business and results of operations.

Cyber-attacks targeting systems and infrastructure used by the oil and gas industry may adversely impact the Partnership’s operations.

The Partnership’s business has become increasingly dependent on digital technologies to conduct certain exploration, development, production and financial activities. The Partnership depends on digital technology to estimate quantities of oil and gas reserves, process and record financial and operating data, analyze seismic and drilling information, and communicate with the general partner and third-party partners. Unauthorized access to the Partnership’s seismic data, reserves information or other proprietary information could lead to data corruption, communication interruption, or other operational disruptions in the Partnership’s exploration or production operations. Also, computers control nearly all of the oil and gas distribution systems in the United States and abroad, which are necessary to transport the Partnership’s production to market. A cyber-attack directed at oil and gas distribution systems could damage critical distribution and storage assets or the environment, delay or prevent delivery of production to markets and make it difficult or impossible to accurately account for production and settle transactions.

While the Partnership has not experienced cyber-attacks, there is no assurance that the Partnership will not suffer such attacks and resulting losses in the future. Further, as cyber-attacks continue to evolve, the Partnership may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any vulnerability to cyber-attacks.

Loss of Partnership information and computer systems could adversely affect the Partnership's business.

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

Oil and gas exploration and production activities are complex and involves risks that could lead to legal proceedings resulting in the incurrence of substantial liabilities.

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

Risks Related to the JOBS Act

The JOBS Act will allow the Partnership to postpone the date by which it must comply with certain laws and regulations intended to protect investors and reduce the amount of information provided in reports filed with the SEC.

The JOBS Act is intended to reduce the regulatory burden on emerging growth companies. The Partnership meets the definition of an emerging growth company and so long as the Partnership qualifies as an emerging growth company, the Partnership may, among other things:

- be exempt from the provisions of Section 404(b) of the Sarbanes-Oxley Act requiring that the Partnership's independent registered public accounting firm provide an attestation report on the effectiveness of its internal control over financial reporting;
- be exempt from the "say on pay" provisions (requiring a non-binding shareholder vote to approve compensation of certain executive officers) and the "say on golden parachute" provisions (requiring a non-binding shareholder vote to approve golden parachute arrangements for certain executive officers in connection with mergers and certain other business combinations) of the Dodd-Frank Act and certain disclosure requirements of the Dodd-Frank Act relating to compensation of the Partnership's chief executive officer;
- be permitted to omit the detailed compensation discussion and analysis from proxy statements and reports filed under the Securities Exchange Act of 1934 and instead provide a reduced level of disclosure concerning executive compensation; and
- be exempt from any rules that may be adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report on the financial statements.

The Partnership currently intends to take advantage of all of the reduced regulatory and reporting requirements that will be available to it so long as the Partnership qualifies as an emerging growth company. The Partnership cannot predict if investors will find its common units less attractive because the Partnership may rely on these exemptions.

Tax Risks to Common Unitholders

The Partnership's tax treatment depends on its status as a partnership for U.S. federal income tax purposes and not being subject to a material amount of entity-level taxation by individual states. If the Internal Revenue Service treats the Partnership as a corporation or the Partnership becomes subject to a material amount of entity-level taxation for state tax purposes, it would reduce the amount of cash available for distribution to the Partnership's common unitholders.

The anticipated after-tax economic benefit of an investment in the common units depends largely on the Partnership being treated as a partnership for U.S. federal income tax purposes. The Partnership has not requested, and does not plan to request, a ruling from the Internal Revenue Service ("IRS") on this or any other tax matter affecting it.

If the Partnership was treated as a corporation for U.S. federal income tax purposes, the Partnership would pay federal income tax on the Partnership's taxable income at the corporate tax rate, which, effective January 1, 2018, is currently a maximum of 21% and likely would pay state income tax at varying rates. Distributions to you would generally be taxed again as corporate distributions, and no income, gains, losses or deductions would flow through to you. Because a tax would be imposed upon the Partnership as a corporation, cash available for distribution to you would be substantially reduced. Therefore, treatment of the Partnership as a corporation would result in a material reduction in the anticipated cash flows and after-tax return to the unitholders, likely causing a substantial reduction in the value of the Partnership's common units.

Current law may change so as to cause the Partnership to be treated as a corporation for U.S. federal income tax purposes or otherwise subject the Partnership to entity-level taxation. In addition, because of widespread state budget deficits and other reasons, several states have ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of such taxes on the Partnership will reduce the cash available for distribution to a unitholder.

An IRS contest of the Partnership's U.S. federal income tax positions may adversely affect the value for the Partnership's common units, and the cost of any IRS contest will reduce the Partnership's cash available for distribution to the Partnership's unitholders.

The Partnership has not requested a ruling from the IRS with respect to its treatment as a partnership for U.S. federal income tax purposes or any other matter affecting the Partnership. It may be necessary to resort to administrative or court proceedings to sustain some or all of the Partnership's counsel's conclusions or the positions the Partnership takes. A court may not agree with all of the Partnership's counsel's conclusions or positions the Partnership takes. Any contest with the IRS may materially and adversely impact the value of the Partnership's units. In addition, costs incurred in any contest with the IRS will be borne indirectly by holders of common units and the General Partner because the costs will reduce the Partnership's cash available for distribution.

You may be required to pay the Partnership to cover taxes, interest and penalties that may arise from an IRS audit.

Beginning in 2018, partnerships may be liable for taxes, interest and penalties that may arise in connection with an IRS audit. In connection with such an audit, the Partnership will have the right to be indemnified by the unitholders for the audited period (including former unitholders), but only to the extent allocable to each unitholder's interests.

You may be required to pay taxes on income from the Partnership even if you do not receive any cash distributions from the Partnership.

Because holders of the Partnership's common units will be treated as partners to whom the Partnership will allocate taxable income which could be different in amount than the cash the Partnership distributes, you will be required to pay any federal income taxes and, in some cases, state and local income taxes on your share of the Partnership's taxable income even if you receive no cash distributions from the Partnership. You may not receive cash distributions from the Partnership equal to your share of the Partnership's taxable income or even equal to the tax liability that results from that income.

The availability of the Partnership's losses may be limited.

The ability of non-corporate and certain corporate unitholders to deduct certain losses generated by the Partnership may be limited by the at-risk rules and certain other limitations. Application of these and certain other rules may limit the ability of unitholders to recognize currently their allocable shares of the Partnership's losses and deductions.

You may not qualify for percentage depletion deductions, and even if you do so qualify, you will be required to determine, and maintain records supporting, your deduction.

Percentage depletion is generally available with respect to common unitholders who qualify under the independent producer exemption contained in Code Section 613A(c). 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. The Partnership cannot determine whether or provide any assurance that you will qualify as an independent producer. Further, if you do qualify as an independent producer, you are required to determine the amount of your allowed percentage depletion deduction and maintain records supporting such determination.

The Partnership cannot assure you whether percentage depletion will be available to a particular common unitholder or the extent of the percentage depletion deduction available to any particular common unitholder.

The Partnership cannot assure you with respect to the availability or extent of percentage depletion deductions to any particular common unitholders for any taxable year. The Partnership encourages you to consult your tax advisor to determine whether percentage depletion would be available to you.

The Partnership cannot assure you that it will meet the requirements for you to deduct intangible drilling and development costs.

Federal tax law places substantial limits on taxpayers' ability to deduct intangible drilling and development costs ("IDCs"). Generally speaking, an "operator" is permitted to elect to currently deduct, or capitalize and deduct ratably over a 60-month period, costs that are properly characterized as IDCs that the operator incurs in connection with the drilling and development of oil and natural gas wells. For purposes of deducting IDCs, an "operator" is generally defined as one that owns a working or an operating interest in an oil or gas well. If the Partnership determines that it is an "operator" with respect to its oil and gas wells, the Partnership's determination is not binding on the IRS. The IRS may assert that the Partnership is not an "operator" with respect to one or more of its oil or gas wells at the time that IDCs are incurred. If the IRS were successful in such a challenge, the Partnership and, therefore, you, would not be entitled to deduct the IDCs incurred in connection with such wells.

If the Partnership is eligible to deduct IDCs, the Partnership cannot assure you that IDCs will be deductible in any given year.

If the Partnership is deemed to be an operator with respect to one or more of its oil or gas wells, its classification of a cost as an IDC is not binding on the IRS. The IRS may reclassify an item classified by the Partnership as an IDC as a cost that must be capitalized or that is not deductible.

The IRS could challenge the timing of the Partnership's deductions of IDCs, which could result in an increase your tax liabilities.

IDCs are generally deductible when the well to which the costs relate is drilled. In some cases, IDCs may be paid in one year for a well that is not drilled until the following year. In those cases, the prepaid IDCs will not be deductible until the year when the well is drilled unless (i) drilling on the well to which the prepayment relates starts within 90 days after the end of the year the prepayment is made or (ii) it is reasonable to expect that the well will be fully drilled within 3-1/2 months of the prepayment. All of the Partnership's wells may not be drilled during the year when the Partnership pays IDCs pursuant to a drilling contract. As a result, the Partnership could fail to satisfy the requirements to deduct the IDCs in the year when paid and/or the IRS may challenge the timing of the Partnership's deduction of prepaid IDCs.

The deduction for IDCs may not be available to you if you do not have passive income.

If you invest in the Partnership, your share of the Partnership's deduction for IDCs in the year you invest will be a passive loss that can be used to offset only passive income. Such deductions cannot be used to offset "active" income, such as salary and bonuses, or portfolio income, such as dividends and interest income. Any unused passive loss from IDCs may be carried forward indefinitely by you to offset your passive income in subsequent taxable years. Certain taxpayers are not subject to the passive loss rules.

On the disposition of property by the Partnership or of common units by you, certain deductions for IDCs, depletion, and depreciation must be recaptured as ordinary income.

You may be required to recapture as ordinary income certain deductions for IDCs, depletion, and depreciation on disposition of property by the Partnership or on disposition of the Partnership's common units.

The Partnership cannot assure you whether the deduction related to U.S. production activities will be available to a particular common unitholder or the extent of any such deduction to any particular common unitholder.

The Code Section 199 deduction is required to be computed separately by each common unitholder. Consequently, no assurance can be given by the Partnership as to the availability or extent of the Code Section 199 deduction to any particular common unitholder. The Partnership encourages you to consult your tax advisor to determine whether the Code Section 199 deduction would be available to you.

Tax gain or loss on disposition of common units could be more or less than expected.

If you sell your common units, you will recognize a gain or loss equal to the difference between the amount realized and your tax basis in those units. Prior distributions to you in excess of the total net taxable income you were allocated for a common unit, which decreased your tax basis in that unit, will, in effect, become taxable income to you if the common unit is sold at a price greater than your tax basis in that unit, even if the price is less than your original cost. As discussed above, a substantial portion of the amount realized, whether or not representing gain, may be ordinary income. In addition, if you sell your common units, you may incur a tax liability in excess of the amount of cash you receive from the sale.

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

Investment in common units by tax-exempt entities, such as individual retirement accounts ("IRAs"), and non-U.S. persons raises issues unique to them. For example, much of the Partnership's income allocated to organizations that are exempt from federal income tax, including IRAs, will be unrelated business taxable income and will be taxable to them. Similarly, much of the Partnership's income allocable to non-U.S. persons will constitute effectively connected U.S. trade or business income, and non-U.S. persons will be required to file U.S. federal tax returns and pay tax on their share of the Partnership's taxable income.

The sale or exchange of 50% or more of the Partnership's capital and profits interests during any twelve-month period will result in the termination of the Partnership for U.S. federal income tax purposes.

The Partnership will be considered to have terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in the Partnership's capital and profits within a twelve-month period. For example, an exchange of 50% of the Partnership's capital and profits could occur if, in any twelve-month period, holders of the Partnership's common units sell at least 50% of the interests in the Partnership's capital and profits. The Partnership's termination would, among other things, result in the closing of its taxable year for all holders of common units and could result in a deferral of certain deductions allowable in computing the Partnership's taxable income.

Holders of common units may be subject to state and local taxes and tax return filing requirements in states where they do not live as a result of investing in the Partnership's common units.

In addition to federal income taxes, you will likely be subject to other taxes, including state and local taxes, unincorporated business taxes and estate, inheritance or intangible taxes that are imposed by the various jurisdictions in which the Partnership does business or owns property, even if you do not live in any of those jurisdictions. You will likely be required to file state and local income tax returns and pay state and local income taxes in some or all of these jurisdictions. Further, you may be subject to penalties for failure to comply with those requirements.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

The U.S. legislature regularly considers budget proposals that may impact many tax incentives and deductions that are currently used by U.S. oil and gas companies. Among others, budget provisions may include: repeal of the deduction of IDC; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; and an increase in the amortization period for geological and geophysical costs of independent producers.

The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could increase the amount of the Partnership's taxable income allocable to you. The Partnership is unable to predict whether any of these changes, or other proposals, will ultimately be enacted. Any modifications to the federal income tax laws or interpretations thereof may or may not be applied retroactively. Any such changes could negatively impact the value of an investment in the Partnership's common units.

Item 1B. Unresolved Staff Comments

None

Item 2. Properties

The Partnership did not own any properties at December 31, 2017. See information regarding the Partnership's acquisition of the Bakken Assets in February 2018 in "Item 1. Business", and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Oil and Gas Properties Acquired and Liquidity and Capital Resources: Oil and Gas Properties" contained herein.

Item 3. Legal Proceedings

At the end of the period covered by this Annual Report on Form 10-K, the Partnership was not a party to any material, pending legal proceedings.

Item 4. Mine Safety Disclosures

Not applicable.

Part II

Item 5. Market For Registrant's Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

Common Units

The Partnership's Registration Statement on Form S-1 (File No. 333-216891) was declared effective by the Securities and Exchange Commission on May 17, 2017. Under the public offering the Partnership made under the Registration Statement (as supplemented), the Partnership is offering common units of limited partner interest (the "common units") on a best-efforts basis with the intention of raising up to $350,000,001 of capital, consisting of 17,631,579 common units. Upon closing of the minimum offering, the organizational limited partner withdrew its initial capital contribution of $990, and the General Partner received Incentive Distribution Rights. As of December 31, 2017, the Partnership had completed the sale of 3,191,231 common units for total gross proceeds of $61.2 million and proceeds net of offering costs including selling commissions and marketing expenses of $57.0 million. As of December 31, 2017, 14,440,348 common units remained unsold. As of February 22, 2018, the common units were held by approximately 1,300 unitholders. The offering will expire on May 17, 2019, unless extended by the General Partner, provided that the offering will be terminated if all of the common units are sold before then. The public offering is being made through David Lerner Associates, Inc. (the "Managing Dealer"). In October 2017, the Partnership completed the sale of 2,631,579 common units at $19.00 per common unit, or $50 million. All subsequent common units are being sold at $20.00 per common unit.

Under the Partnership's agreement with the Managing Dealer, the Managing Dealer receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Managing Dealer also has Dealer Manager Incentive Fees, which is a cash payment of up to an amount equal to 4% of gross proceeds of the common units sold based on the performance of the Partnership. Based on the common units sold through December 31, 2017, the Managing Dealer Incentive Fees are up to approximately $2.4 million, subject to Payout (defined below).

There is currently no established public trading market in which the Partnership's common units are traded. The net proceeds of the ongoing best-efforts offering as of December 31, 2017 have been used as follows:

Units Registered							
	2,631,579	Units	$	19.00	per unit	$	50,000,001
	15,000,000	Units	$	20.00	per unit		300,000,000
Totals:	17,631,579	Units				$	350,000,001
Units Sold							
	2,631,579	Units	$	19.00	per unit	$	50,000,001
	559,652	Units	$	20.00	per unit		11,193,039
Totals:	3,191,231	Units				$	61,193,040

Expenses of Issuance and Distribution of Units		
1. Underwriting commissions	$	3,671,582
2. Expenses of underwriters		-
3. Direct or indirect payments to directors or officers of the Partnership or their associates, or to affiliates of the Partnership		-
4. Fees and expenses of third parties		507,025
Total Expenses of Issuance and Distribution of Common Shares		4,178,607
Net Proceeds to the Partnership	$	57,014,433
1. Purchase of oil, gas and natural gas liquids properties (net of debt, proceeds and repayment including interest and acquisition costs)	$	-
2. Deposits and other costs associated with potential oil, natural gas and natural gas liquids acquisitions		8,754,190
3. Repayment of other indebtedness, including interest expense paid		-
4. Investment and working capital		46,801,845
5. Fees and expenses of third parties		-
6. Other		-
7. Distributions		1,458,398
Total Application of Net Proceeds to the Partnership	$	57,014,433

Distribution Policy

Prior to “Payout,” which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights and will not pay the Dealer Manager Incentive Fees to the Managing Dealer, until Payout occurs.

The Partnership Agreement provides that “Payout”, which is defined below, occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines “Payout Accrual” as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership’s assets, will be made as follows:

First, (i) to the Record Holders of the Incentive Distribution Rights, 30%; (ii) to the Managing Dealer, the “Dealer Manager Incentive Fees”, 30%, until such time as the Managing Dealer receives 4% of the gross proceeds of the common units sold; and (iii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 60%; and (ii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

All items of income, gain, loss and deduction will be allocated to each Partner’s capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2017, the Partnership paid distributions of $0.598357 per common unit, or $1.5 million. The Partnership began paying distributions upon reaching the minimum offering in July 2017.

Neither the Partnership nor the General Partner has adopted an equity compensation plan.

Item 6. Selected Financial Data

Not applicable.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis should be read in conjunction with Item 8 – the Consolidated Financial Statements and Notes thereto, the introduction of Part I regarding "Forward-Looking Statements," and Item 1A – Risk Factors appearing elsewhere in this Annual Report on Form 10-K.

Overview

Energy Resources 12, L.P. (the "Partnership") was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on December 30, 2016. The Partnership is offering common units of limited partner interest (the "common units") on a best-efforts basis with the intention of raising up to $350,000,001 of capital, consisting of 17,631,579 common units. The Partnership's Registration Statement on Form S-1 (File No. 333-216891) was declared effective by the Securities and Exchange Commission on May 17, 2017. As of July 25, 2017, the Partnership completed the sale of the minimum offering of common units for gross proceeds of approximately $25 million. The subscribers to the common units were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time. Additionally upon closing of the minimum offering, the organizational limited partner withdrew its initial capital contribution of $990 and Energy Resources 12 GP, LLC (the "General Partner") received Incentive Distribution Rights (defined below). As of December 31, 2017, the Partnership had sold 3.2 million common units for gross proceeds of $61.2 million and proceeds net of offering costs of $57.0 million.

The Partnership has no officers, directors or employees. Instead, the General Partner manages the day-to-day affairs of the Partnership. All decisions regarding the management of the Partnership are made by the General Partner are made by the Board of Directors of the General Partner and its officers.

The Partnership was formed to acquire primarily oil and gas properties located onshore in the United States. The Partnership seeks to acquire working and other interests in producing and non-producing oil and natural gas properties in the United States and utilize third-party operators to manage the day-to-day operations of such properties.

Results of Operations

As of December 31, 2017, the Partnership had not acquired any assets. As a result, the Partnership's management is not aware of any material trends or uncertainties, favorable or unfavorable, other than national economic conditions affecting the Partnership's targeted investments, which may be reasonably anticipated to have a material impact on the capital resources and the revenue or income to be derived from the operation of assets.

Oil and Gas Properties Acquisition

On November 21, 2017, Energy Resources 12 Operating Company, LLC ("Buyer"), a wholly-owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement ("Purchase Agreement") with Bruin E&P Non-Op Holdings, LLC ("Seller"), for the potential purchase of Seller's interest in certain non-operated oil and gas properties and the related rights, resulting in an approximate average 3.1% non-operated working interest in approximately 204 existing producing wells and approximately 547 future development locations, predominantly in McKenzie, Dunn, McLean and Mountrail counties of North Dakota (collectively, the "Bakken Assets"). The Buyer closed on the purchase of the Bakken Assets on February 1, 2018.

Prior to this acquisition, the Partnership owned no oil and natural gas assets. Neither the Buyer nor the Partnership will be the operator of the Bakken Assets; the current, experienced operators will continue to operate on behalf of the Partnership and other working interest owners. There are twelve current operators, including WPX Energy (NYSE: WPX), Marathon Oil (NYSE: MRO), EOG Resources (NYSE: EOG) and Continental Resources (NYSE: CLR). The Bakken Assets are located in the Bakken Shale formation, including the Antelope, Spotted Horn, Squaw Creek and Reunion Bay fields. The Bakken Shale and its close geologic cousin, the Three Forks Shale, are found in the Williston Basin, centered in North Dakota and are two of the largest oil fields in the U.S. While oil has been produced in North Dakota from the Williston Basin since the 1950s, it is only since 2007 through the application of horizontal drilling and hydraulic fracturing technologies that the Bakken has seen an increase in production activities.

The purchase price for the Bakken Assets was $87.5 million, subject to customary post-closing adjustments. The purchase price was funded by net proceeds from the Partnership's ongoing public offering, proceeds from an unsecured term loan (discussed in "Financing" below) and an advance from a member of the General Partner of $7.0 million. The advance does not bear interest and the member of the General Partner did not receive any compensation for the advance. The advance is planned to be repaid with future proceeds from the Partnership's ongoing public offering.

The Partnership anticipates that it may be obligated to invest approximately $10 to $15 million in drilling and completion capital expenditures in 2018 (eleven months from February 1, 2018 to December 31, 2018), and a total of approximately $65 to $70 million in drilling and completion capital expenditures from February 1, 2018 through 2023 to fully participate in operator drilling programs in the Bakken Assets without becoming subject to non-consent penalties under the joint operating agreements governing the Bakken Assets. Since the Partnership is not the operator of any of the Bakken Assets described, it is extremely difficult to predict the levels of future participation in the drilling and completion of new wells and their associated capital expenditures. This makes capital expenditures for drilling and completion projects for 2019 and beyond difficult to forecast and current estimated capital expenditure could be significantly different from amounts actually invested. The Partnership expects to fund capital additions related to the drilling and completion of wells primarily from cash provided by operating activities, proceeds from its best-efforts offering and cash on hand.

Transactions with Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to existing related party transactions, as well as any new significant related party transactions.

Advisory and Cost Sharing Agreements

In November 2017, the Partnership engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting the Buyer through closing and post-closing of the Purchase Agreement discussed in "Oil and Gas Properties Acquisition" above. The Partnership will pay REI a total of approximately $5.3 million for its advisory and consulting services. At December 31, 2017, the Partnership has accrued the $5.3 million advisory and consulting services fee, which is included in the consolidated balance sheets in Accounts payable and accrued expenses. Of the $5.3 million total, approximately $4.8 million is included as Deferred acquisition costs related to the costs of advisory and due diligence performed by REI on the Bakken Assets on the consolidated balance sheets, and the remaining approximate $0.5 million has been expensed and is shown as Transaction costs on the consolidated statements of operations for costs for services related to the due diligence performed in pursuit of assets that were not acquired by the Partnership. REI is also entitled to a fee of 5% of the gross sales price in the event the Buyer disposes any or all of the Bakken Assets, if surplus funds are available after Payout to the holders of the Partnership's common units, as defined below.

REI is owned by entities that are controlled by Anthony F. Keating, III, Co-Chief Operating Officer of Energy 11 GP, LLC, and Michael J. Mallick, Co-Chief Operating Officer of Energy 11 GP, LLC. Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of Energy 11 GP, LLC as well as the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner. Energy 11 GP, LLC is the general partner of Energy 11, L.P. ("Energy 11"), a limited partnership that also invests in producing and non-producing oil and gas properties on-shore in the United States.

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11 to provide access to Energy 11's personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for the Partnership. The shared day-to-day costs will be split evenly between the two partnerships and any direct third-party costs will be paid by the party receiving the services. The shared costs will be based on actual costs incurred with no mark-up or profit for Energy 11. The agreement may be terminated at any time by either party upon 60 days written notice. As noted above, the officers and members of the Partnership's General Partner are also officers and members of the general partner of Energy 11.

Advance from member of the General Partner

To fund the purchase price of the Bakken Assets, a member of the General Partner made an advance to the Partnership of $7.0 million. The advance does not bear interest and the member of the General Partner did not receive any compensation for the advance. The advance is planned to be repaid with future proceeds from the Partnership's ongoing public offering.

See further discussion in "Note 6. Related Parties" in Part II, Item 8 of this Form 10-K and in Part III, Item 13 – "Certain Relationships and Related Transactions, and Director Independence" below.

Management fee

With the Partnership’s closing on the Bakken Assets on February 1, 2018, the Partnership will begin payment of the management fee at the end of the first quarter of 2018. As described in the Prospectus, the Partnership will pay quarterly an annual management fee of 0.5% of the total gross equity proceeds raised in this offering to the General Partner. The fees and expenses paid to the general partner will be in exchange for the services the general partner will render to the Partnership, including administering the day-to-day operations of the Partnership; performing or supervising the various administrative functions necessary to manage the Partnership; identifying producing and non-producing properties for potential acquisition; evaluating, contracting for and acquiring these properties and managing the development of these properties; and monitoring or hiring a third party to monitor the operator(s) of the properties the Partnership acquires, including recommending whether the Partnership should participate in the development of such properties by the operators of the properties.

Liquidity and Capital Resources

The Partnership’s principal source of liquidity will be the proceeds of the best-efforts offering and the cash flow generated from properties the Partnership acquired on February 1, 2018. The Partnership anticipates that cash on hand, cash flow from operations and proceeds of the best-efforts offering will be adequate to meet its liquidity requirements for at least the next 12 months, including the acquisition of the Bakken Assets as discussed above and the debt discussed below. If the Partnership is unable to raise sufficient proceeds from its ongoing best-efforts offering or obtain additional financing, it may be unable to pay distributions or participate in the drilling programs discussed above.

Financing

On January 16, 2018, the Partnership, as the borrower, entered into a loan agreement (the “Loan Agreement”) with Bank of America, N.A. (the “Lender”), which provides for an unsecured term loan (the “Term Loan”) of $25 million. The Term Loan bears interest at a variable rate based on the London Inter-Bank Offered Rate (LIBOR) plus a margin of 2.00%. Interest is payable monthly. The maturity date is January 15, 2019.

The Term Loan proceeds were used in closing on the Partnership’s purchase of the Bakken Assets, as described above. Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. Glade M. Knight and David S. McKenney, the General Partner’s Chief Executive Officer and Chief Financial Officer, respectively, have guaranteed repayment of the Term Loan and did not receive any consideration in exchange for providing this guarantee. The Partnership intends to use proceeds from its best-efforts offering to repay the Term Loan.

Partners’ Equity

The Partnership intends to continue to raise capital through its best-efforts offering of common units by the Managing Dealer at $20.00. Under the agreement with the Managing Dealer, the Managing Dealer receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Managing Dealer also has Dealer Manager Incentive Fees (defined below) where the Managing Dealer could receive distributions up to an additional 4% of gross proceeds of the common units sold in the Partnership’s best-efforts offering as outlined in the prospectus based on the performance of the Partnership. Based on the common units sold through December 31, 2017, the Dealer Manager Incentive Fees are approximately $2.4 million, subject to Payout (defined below).

As of July 25, 2017, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. As of December 31, 2017, the Partnership had completed the sale of 3,191,231 common units for gross proceeds of approximately $61.2 million and proceeds net of offering costs of approximately $57.0 million. In October 2017, the Partnership completed the sale of all common units at $19.00 (2,631,579 common units). In accordance with the prospectus, all subsequent common units are being sold at $20.00 per common unit.

Distributions

Prior to “Payout,” which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights and will not pay the Dealer Manager Incentive Fees to the Managing Dealer, until Payout occurs.

The Partnership Agreement provides that "Payout", which is defined below, occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership's assets, will be made as follows:

First, (i) to the Record Holders of the Incentive Distribution Rights, 30%; (ii) to the Managing Dealer, the "Dealer Manager Incentive Fees", 30%, until such time as the Managing Dealer receives 4% of the gross proceeds of the common units sold; and (iii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 60%; and (ii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

All items of income, gain, loss and deduction will be allocated to each Partner's capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2017, the Partnership paid distributions of $0.598357 per common unit, or $1.5 million.

Since distributions to date have been funded with proceeds from the offering of common units, the Partnership's ability to maintain its current intended rate of distribution will be based on its ability to fully invest its offering proceeds and thereby increase its cash generated from operations. As there can be no assurance of the Partnership's ability to acquire properties that provide income at this level, there can be no assurance as to the classification or duration of distributions at the current rate. Proceeds of the offering which are distributed are not available for investment in properties.

Critical Accounting Policies

The Partnership's critical accounting policies are important to the portrayal of both its financial condition and results of operations and require the Partnership to make difficult, subjective or complex assumptions or estimates about matters that are uncertain. The Partnership would report different amounts in its consolidated financial statements, which could be material, if the Partnership used different assumptions or estimates. The Partnership believes that the following are the critical accounting policies used in the preparation of its consolidated financial statements.

Adoption of Accounting Standard Update 2017-01

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2017-01, Business Combinations (Topic 805), which amended the existing accounting standards to clarify the definition of a business and assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The Partnership adopted this standard effective January 1, 2017 and will apply the principles of this ASU for its February 2018 acquisition of the Bakken Assets. The Partnership intends to treat the acquisition of the Bakken Assets as an asset purchase.

Property and Depreciation, Depletion and Amortization

The Partnership will account for its oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

No gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Impairment

The Partnership will assess its proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, the Partnership recognizes an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management's outlook of future commodity prices. Where probable and possible reserves exist, an appropriately risk adjusted amount of these reserves is included in the impairment evaluation. The underlying commodity prices used in the determination of estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Accounting for Asset Retirement Obligations

The Partnership will have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. The removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

The Partnership will record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues will be recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of the Partnership's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

The Partnership will not operate its oil and natural gas properties and, therefore, receives actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well will be used to estimate the accrual of revenue on these wells. The oil, natural gas and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, natural gas and NGLs. These variables could lead to an over or under accrual of oil, natural gas and NGL sales at the end of any particular quarter. However, the Partnership adjusts the estimated accruals of revenue to actual production in the period actual production is determined.

Recent Accounting Standards

See Note 2. Summary of Significant Accounting Policies in Part II, Item 8 – Financial Statements and Supplementary Data for a summary of recent accounting standards.

Subsequent Events

In January 2018, the Partnership closed on the issuance of approximately 0.2 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $4.2 million and proceeds net of selling and marketing costs of approximately $4.0 million.

In January 2018, the Partnership declared and paid $0.3 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

On January 16, 2018, the Partnership entered into a $25 million term loan with Bank of America, N.A. as the lender. See discussion in “Financing” above for more details about the Term Loan.

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11 to provide access to Energy 11’s personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for the Partnership. See “Advisory and Cost Sharing Agreements” in the section entitled Transactions with Related Parties above for more details about the cost sharing agreement.

On February 1, 2018, the Partnership, through its wholly-owned subsidiary, closed on the acquisition of the Bakken Assets for a purchase price of $87.5 million, subject to customary adjustments. The purchase price was funded by net proceeds from the Partnership’s ongoing public offering, proceeds from the Term Loan discussed above and an advance from a member of the General Partner of $7.0 million. See discussion in “Oil and Gas Properties Acquisition” above for more details about this acquisition.

In February 2018, the Partnership closed on the issuance of approximately 0.2 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $4.0 million and proceeds net of selling and marketing costs of approximately $3.7 million.

In February 2018, the Partnership declared and paid $0.4 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

Item 8. Financial Statements and Supplementary Data

Financial Statements

Report of Independent Registered Public Accounting Firm

To the Shareholders and the General Partner of Energy Resources 12, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Energy Resources 12, L.P. (the “Partnership”) as of December 31, 2017 and 2016, the related consolidated statements of operations, Partners’ equity, and cash flows for the year ended December 31, 2017 and the period December 30, 2016 (initial capitalization) through December 31, 2016, and the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Partnership at December 31, 2017 and 2016, and the results of operations and its cash flows for the year ended December 31, 2017 and for the period December 30, 2016 (initial capitalization) through December 31, 2016, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Partnership’s management. Our responsibility is to express an opinion on the Partnership’s financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Partnership’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

We have served as the Partnership’s auditor since 2017.

Richmond, Virginia
February 26, 2018

Energy Resources 12, L.P.
Consolidated Balance Sheets

		December 31, 2017		December 31, 2016
Assets				
Cash	$	46,859,728	$	1,000
Deposit for potential acquisition		8,750,000		-
Deferred acquisition costs		4,884,208		-
Deferred offering costs		-		22,975
Total Assets	$	60,493,936	$	23,975
Liabilities				
Accounts payable and accrued expenses	$	5,448,409	$	23,245
Total Liabilities		5,448,409		23,245
Partners' Equity				
Limited partners' interest (3,191,231 and 0 common units issued and outstanding, respectively)		55,045,742		723
General partner's interest		(215)		7
Total Partners' Equity		55,045,527		730
Total Liabilities and Partners' Equity	$	60,493,936	$	23,975

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Consolidated Statements of Operations

	Year Ended December 31, 2017	For the period December 30, 2016 (Initial Capitalization) through December 31, 2016
Revenue	$ -	$ -
Transaction costs	525,000	-
General and administrative expenses	99,410	270
Operating loss	(624,410)	(270)
Interest income, net	114,163	-
Net loss	$ (510,247)	$ (270)
Basic and diluted net income (loss) per common unit	$ (0.48)	$ -
Weighted average common units outstanding - basic and diluted	1,067,941	-

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Consolidated Statements of Partners' Equity

	Limited Partner Amount	General Partner Amount	Total Partners' Equity
Initial capitalization - December 30, 2016	$ 990	$ 10	$ 1,000
2016 Net loss	(267)	(3)	(270)
Balance - December 31, 2016	723	7	730
Net proceeds from issuance of common units	57,014,432	-	57,014,432
Distributions to organizational limited partner	(990)	-	(990)
Distributions declared and paid to common units ($0.598357 per unit)	(1,458,398)	-	(1,458,398)
2017 Net loss	(510,025)	(222)	(510,247)
Balance - December 31, 2017	$ 55,045,742	$ (215)	$ 55,045,527

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Consolidated Statements of Cash Flows

	For the year ended December 31, 2017	For the period December 30, 2016 (Initial Capitalization) through December 31, 2016
Cash flow from operating activities:		
Net loss	$ (510,247)	$ (270)
Changes in operating assets and liabilities:		
Deferred acquisition costs	(4,190)	
Accounts payable and accrued expenses	560,832	270
Net cash used in operating activities	46,395	-
Cash flow from investing activities		
Deposit for acquisition of oil, natural gas and natural gas liquids properties	(8,750,000)	-
Net cash used in investing activities	(8,750,000)	-
Cash flow from financing activities		
Net proceeds related to issuance of common units	57,020,731	-
Net proceeds from line of credit	229,000	
Payments on line of credit	(229,000)	
Distributions paid to limited partners	(1,458,398)	-
Net cash provided by financing activities	55,562,333	-
Increase in cash and cash equivalents	46,858,728	-
Cash and cash equivalents, beginning of period	1,000	1,000
Cash and cash equivalents, end of period	$ 46,859,728	$ 1,000
Interest paid	$ 1,420	$ -
Supplemental information:		
Accrued deferred costs for potential acquisition	4,880,018	-
Accrued deferred offering costs	-	22,975

See notes to consolidated financial statements.

Energy Resources 12, L.P.
Notes to Consolidated Financial Statements
December 31, 2017

Note 1. Partnership Organization

Energy Resources 12, L.P. (together with its wholly-owned subsidiary, the “Partnership”) was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on December 30, 2016. The Partnership is offering common units of limited partner interest (the “common units”) on a best-efforts basis with the intention of raising up to $350,000,001 of capital, consisting of 17,631,579 common units. The Partnership’s offering was declared effective by the Securities and Exchange Commission (“SEC”) on May 17, 2017. As of July 25, 2017, the Partnership completed the sale of the minimum offering of 1,315,790 common units. The subscribers to the common units were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time.

The Partnership’s primary investment objectives are to (i) acquire producing and non-producing oil and gas properties with development potential to be operated by third-party operators, and to enhance the value of the properties through drilling and other development activities, (ii) make distributions to the holders of the common units, (iii) engage in a liquidity transaction after five to seven years, in which all properties are sold and the sales proceeds are distributed to the partners, merge with another entity, or list the common units on a national securities exchange, and (iv) permit holders of common units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the common units primarily will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States, and to develop those properties.

The general partner of the Partnership is Energy Resources 12 GP, LLC (the “General Partner”). The General Partner manages and controls the business affairs of the Partnership. David Lerner Associates, Inc. (the “Managing Dealer”), is acting as the dealer manager for the offering of the common units.

The Partnership’s fiscal year ends on December 31.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying financial statements of the Partnership have been prepared in accordance with United States generally accepted accounting principles (“US GAAP”).

Cash and Cash Equivalents

Cash and cash equivalents consist of highly liquid investments with original maturities of three months or less. The fair market value of cash and cash equivalents approximates their carrying value. Cash balances may at times exceed federal depository insurance limits.

Offering Costs

The Partnership is raising capital through an on-going best-efforts offering of units by the Managing Dealer, which receives a selling commission and a marketing expense allowance based on proceeds of the units sold. Additionally, the Partnership has incurred other offering costs including legal, accounting and reporting services. These offering costs are recorded by the Partnership as a reduction of partners’ equity. As of December 31, 2017, the Partnership had sold 3.2 million common units for gross proceeds of $61.2 million and proceeds net of offering costs of $57.0 million.

Use of Estimates

The preparation of financial statements in conformity with United States GAAP requires management to make estimates and assumptions that affect the reported amounts in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

Income Tax

The Partnership is taxed as a partnership for federal and state income tax purposes. No provision for income taxes has been recorded since the liability for such taxes is that of each of the partners rather than the Partnership. The Partnership's income tax returns are subject to examination by the federal and state taxing authorities, and changes, if any, could adjust the individual income tax of the partners.

The Partnership has evaluated whether any material tax position taken will more likely than not be sustained upon examination by the appropriate taxing authority and believes that all such material tax positions taken are supportable by existing laws and related interpretations.

Property and Depreciation, Depletion and Amortization

The Partnership will account for its oil and natural gas properties using the successful efforts method of accounting. Under this method, costs of productive exploratory wells, development dry holes and productive wells and undeveloped leases are capitalized. Oil and natural gas lease acquisition costs are also capitalized. Exploration costs, including personnel costs, certain geological and geophysical expenses and delay rentals for oil and natural gas leases, are charged to expense during the period the costs are incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the well is determined not to have found reserves in commercial quantities.

No gains or losses are recognized upon the disposition of proved oil and natural gas properties except in transactions such as the significant disposition of an amortizable base that significantly affects the unit–of–production amortization rate. Sales proceeds are credited to the carrying value of the properties.

The application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as development or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results from a drilling operation can take considerable time to analyze and the determination that commercial reserves have been discovered requires both judgment and industry experience. Wells may be completed that are assumed to be productive and actually deliver oil, natural gas and natural gas liquids in quantities insufficient to be economic, which may result in the abandonment of the wells at a later date. Wells are drilled that have targeted geologic structures that are both developmental and exploratory in nature, and an allocation of costs is required to properly account for the results. Delineation seismic incurred to select development locations within an oil and natural gas field is typically considered a development cost and capitalized, but often these seismic programs extend beyond the reserve area considered proved and management must estimate the portion of the seismic costs to expense. The evaluation of oil and natural gas leasehold acquisition costs requires managerial judgment to estimate the fair value of these costs with reference to drilling activity in a given area. Drilling activities in an area by other companies may also effectively condemn leasehold positions.

Impairment

The Partnership will assess its proved oil and natural gas properties for possible impairment whenever events or circumstances indicate that the recorded carrying value of the properties may not be recoverable. Such events include a projection of future reserves that will be produced from a field, the timing of this future production, future costs to produce the oil, natural gas and natural gas liquids and future inflation levels. If the carrying amount of a property exceeds the sum of the estimated undiscounted future net cash flows, the Partnership recognizes an impairment expense equal to the difference between the carrying value and the fair value of the property, which is estimated to be the expected present value of the future net cash flows. Estimated future net cash flows are based on existing reserves, forecasted production and cost information and management's outlook of future commodity prices. Where probable and possible reserves exist, an appropriately risk adjusted amount of these reserves is included in the impairment evaluation. The underlying commodity prices used in the determination of estimated future net cash flows are based on NYMEX forward strip prices at the end of the period, adjusted by field or area for estimated location and quality differentials, as well as other trends and factors that management believes will impact realizable prices. Future operating costs estimates, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

Accounting for Asset Retirement Obligations

The Partnership will have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. The removal and restoration obligations are primarily associated with site reclamation, dismantling facilities and plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires management to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

The Partnership will record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

Inherent in the present value calculation are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions of these assumptions impact the present value of the existing asset retirement obligation, a corresponding adjustment is made to the oil and natural gas property balance.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues will be recognized when production is sold to a purchaser at fixed or determinable prices, when delivery has occurred and title has transferred and collectability of the revenue is reasonably assured. Virtually all of the Partnership's contracts' pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of oil, natural gas and natural gas liquids and prevailing supply and demand conditions, so that prices fluctuate to remain competitive with other available suppliers.

The Partnership will not operate its oil and natural gas properties and, therefore, will receive actual oil, natural gas and NGL sales volumes and prices (in the normal course of business) more than a month later than the information is available to the operators of the wells. This being the case, the most current available production data is gathered from the appropriate operators, and oil, natural gas and NGL index prices local to each well will be used to estimate the accrual of revenue on these wells. The oil, natural gas and NGL sales revenue accrual can be impacted by many variables including rapid production decline rates, production curtailments by operators, the shut-in of wells with mechanical problems and rapidly changing market prices for oil, natural gas and NGLs. These variables could lead to an over or under accrual of oil, natural gas and NGL sales at the end of any particular quarter. However, the Partnership will adjust the estimated accruals of revenue to actual production in the period actual production is determined.

Net Loss per Common Unit

Basic net loss per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted net loss per common unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no common units with a dilutive effect for the year ended December 31, 2017. As a result, basic and diluted outstanding common units were the same. There were no outstanding common units for the period ended December 31, 2016. The Incentive Distribution Rights (as discussed in Note 3) are not included in net loss per common unit until such time that it is probable Payout (as discussed in Note 3) would occur.

Recently Adopted Accounting Standards

In January 2017, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2017-01, Business Combinations (Topic 805), which amends the existing accounting standards to clarify the definition of a business and assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, including interim periods within those periods, and should be applied prospectively on or after the effective date. The Partnership adopted this standard effective January 1, 2017.

Recently Issued Accounting Standards

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), that amends the former revenue recognition guidance and provides a revised comprehensive revenue recognition model with customers that contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. Throughout 2016, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 2016-20, 2017-13 and 2017-14, respectively, to clarify specific topics originally described in ASU 2014-09. In August 2015, the FASB issued ASU No. 2015-14, which deferred the effective date of ASU 2014-09 to annual and interim periods beginning after December 15, 2017, and permitted early application for annual reporting periods beginning after December 15, 2016. The Partnership adopted this standard on January 1, 2018. The Partnership did not recognize any revenue for any period prior to adoption of this standard.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the existing accounting standards for lease accounting, including requiring lessees to recognize most leases on their balance sheets as right-of-use assets and lease liabilities. The standard is effective for annual and interim periods beginning after December 15, 2018 with early adoption permitted. The Partnership expects to adopt this standard as of January 1, 2019. The Partnership is still evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

In August 2017, the FASB issued ASU No. 2017-12, *Derivatives and Hedging (Topic 815), Targeted Improvements to Accounting for Hedging Activities*, which amends the hedge accounting model to enable entities to better portray their risk management activities in their financial statements and enhance the transparency and understandability of hedging activity. The standard simplifies the application of hedge accounting and reduces the administrative burden of hedge documentation requirements and assessing hedge effectiveness. The standard is effective for annual and interim periods beginning after December 15, 2018 with early adoption permitted. The standard requires a modified retrospective approach for all hedge relationships that exist on the date of adoption. The presentation and disclosure guidance is required only prospectively. The Partnership plans to adopt this standard in the first quarter of 2018. As of December 31, 2017, the Partnership has no outstanding hedge positions; therefore, the adoption of this standard is not expected to have a material impact on the Partnership’s consolidated financial statements.

Note 3. Oil and Gas Investments

On November 21, 2017, Energy Resources 12 Operating Company, LLC (“Buyer”), a wholly-owned subsidiary of the Partnership, entered into a Purchase and Sale Agreement (“Purchase Agreement”) with Bruin E&P Non-Op Holdings, LLC (“Seller”), for the potential purchase of Seller’s interest in certain non-operated oil and gas properties and the related rights, resulting in an approximate average 3.1% non-operated working interest in approximately 204 existing producing wells and approximately 547 future development locations, predominantly in McKenzie, Dunn, McLean and Mountrail counties of North Dakota (collectively, the “Bakken Assets”). The Buyer closed on the purchase of the Bakken Assets on February 1, 2018. The Buyer will not be the operator of the Bakken Assets; the current, experienced operators will continue to operate the Bakken Assets on behalf of the Buyer and other working interest owners.

Pursuant to the Purchase Agreement, the purchase price for the Bakken Assets is $87.5 million. On November 21, 2017, the Partnership, on behalf of the Buyer, funded a deposit of 10% of the purchase price, or $8.75 million, to the Seller that was applied toward the purchase price at closing. The final settlement purchase price is subject to the customary post-closing adjustments, as defined and identified in the Purchase Agreement.

The closing of the Purchase Agreement was subject to the satisfaction of a number of required conditions which, at December 31, 2017, remained unsatisfied under the Purchase Agreement. Consummation of the acquisition was subject to the Buyer’s satisfactory completion of the review of title, environmental investigations, financial analysis and geological analysis, obtaining sufficient financing to fund the purchase price and other due diligence.

The Partnership has engaged Regional Energy Investors, LP (“REI”) to perform advisory and consulting services, including supporting the Buyer through closing and post-closing of the Purchase Agreement. The Partnership will pay REI a total of approximately $5.3 million for its advisory and consulting services. REI is also entitled to a fee of 5% of the gross sales price in the event the Buyer disposes any or all of the Bakken Assets, if surplus funds are available after Payout to the holders of the Partnership’s common units, as defined Note 4 below. REI is owned by entities that are controlled by Anthony F. Keating, III, Co-Chief Operating Officer of Energy 11 GP, LLC, and Michael J. Mallick, Co-Chief Operating Officer of Energy 11 GP, LLC. Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of Energy 11 GP, LLC as well as the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner. See Note 6. Related Parties below for additional information.

The acquisition-related costs incurred for legal, accounting and environmental review services through December 31, 2017 of approximately $4.9 million were included in Deferred costs for potential acquisition on the Partnership's consolidated balance sheets. Approximately $0.5 million of the fee payable to REI related to due diligence work on potential acquisitions that were not pursued, and therefore, were recorded as Transaction costs in the Partnership's consolidated statements of operations.

Note 4. Capital Contribution and Partners' Equity

At inception, the General Partner and organizational limited partner made initial capital contributions totaling $1,000 to the Partnership. Upon closing of the minimum offering, the organizational limited partner withdrew its initial capital contribution of $990, the General Partner received Incentive Distribution Rights (defined below), and has been and will be reimbursed for its documented third party out-of-pocket expenses incurred in organizing the Partnership and offering the common units.

As of July 25, 2017, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. As of December 31, 2017, the Partnership had completed the sale of 3,191,231 common units for gross proceeds of approximately $61.2 million and proceeds net of offering costs of approximately $57.0 million. In October 2017, the Partnership completed the sale of all common units at $19.00 (2,631,579 common units). In accordance with the prospectus, all subsequent common units are being sold at $20.00 per common unit.

The Partnership intends to continue to raise capital through its best-efforts offering of common units by the Managing Dealer at $20.00. Under the agreement with the Managing Dealer, the Managing Dealer receives a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Managing Dealer also has Dealer Manager Incentive Fees (defined below) where the Managing Dealer could receive distributions up to an additional 4% of gross proceeds of the common units sold in the Partnership's best-efforts offering as outlined in the prospectus based on the performance of the Partnership. Based on the common units sold through December 31, 2017, the Dealer Manager Incentive Fees are approximately $2.4 million, subject to Payout (defined below).

Prior to "Payout," which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of common units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights and will not pay the Dealer Manager Incentive Fees to the Managing Dealer, until Payout occurs.

The Agreement of Limited Partnership of the Partnership (the "Partnership Agreement") provides that "Payout", which is defined below, occurs on the day when the aggregate amount distributed with respect to each of the common units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per common unit, regardless of the amount paid for the common unit. If at any time the Partnership distributes to holders of common units more than the Payout Accrual, the amount the Partnership distributes in excess of the Payout Accrual will reduce the Net Investment Amount.

All distributions made by the Partnership after Payout, which may include all or a portion of the proceeds of the sale of all or substantially all of the Partnership's assets, will be made as follows:

- First, (i) to the Record Holders of the Incentive Distribution Rights, 30%; (ii) to the Managing Dealer, the "Dealer Manager Incentive Fees", 30%, until such time as the Managing Dealer receives 4% of the gross proceeds of the common units sold; and (iii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

- Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 60%; and (ii) to the Record Holders of outstanding common units, 40%, pro rata based on their percentage interest.

All items of income, gain, loss and deduction will be allocated to each Partner's capital account in a manner generally consistent with the distribution procedures outlined above.

For the year ended December 31, 2017, the Partnership paid distributions of $0.598357 per common unit, or $1.5 million.

Note 5. Line of Credit

In February 2017, the Partnership obtained an unsecured line of credit with Bank of America in the principal amount of $500,000 to fund some of its offering and operating costs. On July 25, 2017, the Partnership repaid the outstanding balance on the line of credit of $229,000, which bore interest at a variable rate based on the London InterBank Offered Rate (LIBOR), using proceeds from the sale of common units without a prepayment premium or penalty.

Glade M. Knight, the General Partner's Chief Executive Officer, and David S. McKenney, the General Partner's Chief Financial Officer, had guaranteed repayment of the line of credit and did not receive any consideration in exchange for providing this guarantee.

Note 6. Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors oversees and reviews the Partnership's related party relationships and is required to approve any significant modifications to any existing related party transactions, as well as any new significant related party transactions.

The Partnership has agreed to pay the General Partner an advisory fee to manage the day-to-day affairs of the Partnership, including serving as an investment advisor and consultant in connection with the acquisition, development, operation and disposition of oil and gas properties and other assets of the Partnership. Subsequent to the Partnership's first asset purchase, the Partnership will pay quarterly an annual fee of 0.5% of the total gross equity proceeds raised by the Partnership in its offering as outlined in the prospectus. The fees paid to the General Partner will be expensed as incurred. In addition, the Partnership will also reimburse the General Partner for any costs incurred by the General Partner in organizing the Partnership or incurred in the offering of the common units. For the year ended December 31, 2017, approximately $57,000 of general and administrative costs were incurred by a member of the General Partner and have been or will be reimbursed by the Partnership. At December 31, 2017, approximately $34,000 was due to a member of the General Partner. See discussion above in Note 3. Oil and Gas Investments regarding costs incurred and payable to a related party for due diligence and advisory services provided on the acquisition of the Bakken Assets.

The Chief Executive Officer and Chief Financial Officer of the Partnership's General Partner are also the Chief Executive Officer and Chief Financial Officer of Energy 11 GP, LLC, the general partner of Energy 11, L.P. ("Energy 11"). The Partnership has and anticipates that it will share accounting and administrative resources, including personnel, with Energy 11 to ensure effective staffing of the Partnership. The cost of these accounting and administrative resources will be shared between the partnerships. See discussion below in Note 7. Subsequent Events on the cost sharing agreement.

Note 7. Subsequent Events

In January 2018, the Partnership closed on the issuance of approximately 0.2 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $4.2 million and proceeds net of selling and marketing costs of approximately $4.0 million.

In January 2018, the Partnership declared and paid $0.3 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

On January 16, 2018, the Partnership entered into a loan agreement with Bank of America, N.A., as the lender, for an unsecured term loan of $25 million. The Term Loan bears interest at a variable rate based on the London Inter-Bank Offered Rate (LIBOR) plus a margin of 2.00%. The maturity date is January 15, 2019.

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11 to provide access to Energy 11's personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for the Partnership. The shared day-to-day costs will be split evenly between the two partnerships and any direct third-party costs will be paid by the party receiving the services. The shared costs will be based on actual costs incurred with no mark-up or profit for Energy 11. The agreement may be terminated at any time by either party upon 60 days written notice. The officers and members of the Partnership's General Partner are also officers and members of the general partner of Energy 11.

On February 1, 2018, the Partnership, through its wholly-owned subsidiary, closed on the acquisition of Seller's interest in the Bakken Assets discussed in Note 3. Oil and Gas Investments above. The purchase price of $87.5 million, subject to customary adjustments, was funded by net proceeds from the Partnership's ongoing public offering, proceeds from the unsecured term loan discussed above and an advance from a member of the General Partner of $7.0 million. The advance does not bear interest and the member of the General Partner did not receive any compensation for the advance. The unsecured term loan and the advance are planned to be repaid with future proceeds from the Partnership's ongoing public offering.

In February 2018, the Partnership closed on the issuance of approximately 0.2 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $4.0 million and proceeds net of selling and marketing costs of approximately $3.7 million.

In February 2018, the Partnership declared and paid $0.4 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Rules 13a-15 and 15d-15 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”), the Partnership carried out an evaluation, under the supervision and with the participation of management, including the Chief Executive Officer and Chief Financial Officer of the General Partner, of the effectiveness of the Partnership’s disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and Chief Financial Officer of the General Partner concluded that the Partnership’s disclosure controls and procedures were effective as of December 31, 2017 to provide reasonable assurance that information required to be disclosed in the Partnership’s reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. The Partnership’s disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is accumulated and communicated to the Partnership’s management, including the Chief Executive Officer and Chief Financial Officer of the General Partner, as appropriate, to allow timely decisions regarding required disclosure.

Management’s Annual Report on Internal Control Over Financial Reporting

The Partnership’s management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act. The Partnership has performed an evaluation under the supervision and with the participation of its management, including the Chief Executive Officer and Chief Financial Officer of the General Partner, of the effectiveness of the Partnership’s internal control over financial reporting. The Partnership’s management assessed the effectiveness of its internal control over financial reporting as of December 31, 2017. The Partnership’s management used the criteria set forth in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) to perform its assessment. Based on this assessment, the Partnership’s management, including the Chief Executive Officer and Chief Financial Officer of the General Partner, concluded, that as of December 31, 2017, the Partnership’s internal control over financial reporting was effective based on those criteria.

Changes in Internal Control Over Financial Reporting

There has been no change in the Partnership’s internal control over financial reporting during the quarter ended December 31, 2017 that has materially affected, or is reasonably likely to materially affect, the Partnership’s internal control over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Directors and Executive Officers of the General Partner

As is the case with many partnerships, the Partnership does not directly employ officers, directors or employees. Its operations and activities are managed by the Board of Directors and executive officers of the General Partner. References to the Partnership's directors and executive officers are references to the directors and executive officers of the General Partner.

The following table sets forth the names, ages and offices of the present directors and executive officers of the General Partner as of December 31, 2017:

Name	Age	Position
Glade M. Knight	73	Chief Executive Officer
David S. McKenney	55	Chief Financial Officer and Secretary

The following is a biographical summary of the business experience of these directors and executive officers:

Glade M. Knight. Mr. Knight has been part owner of and the Chief Executive Officer of the General Partner since its formation in December 2016. Mr. Knight is also a part owner of and the Chief Executive Officer of Energy 11 GP, LLC, the general partner of Energy 11, a partnership also focused on investments in the oil and gas industry. Additionally, Mr. Knight has served as Executive Chairman of Apple Hospitality REIT, Inc. since May 15, 2014, and previously served as Chairman and Chief Executive Officer. Mr. Knight was also the founder of Apple REIT Ten, Inc. and served as its Chairman and Chief Executive Officer from its inception until it merged with Apple Hospitality REIT, Inc. in September 2016. Mr. Knight was also the founder of Apple REIT Seven, Inc. and Apple REIT Eight, Inc. (which were real estate investment trusts) and served as the Chairman and Chief Executive Officer of those companies from their inception until the mergers with the Apple Hospitality REIT, Inc., which were completed in March 2014. In addition, Mr. Knight was the Chairman and Chief Executive Officer of Apple REIT Six, Inc., a real estate investment trust, from 2004 until the company merged with an affiliate of Blackstone Real Estate Partners VII in May 2013. Mr. Knight served in the same capacity for Apple Hospitality Five, Inc., another REIT, from 2002 until the company was sold to Inland American Real Estate Trust, Inc. in October 2007, and Apple Hospitality Two, Inc., a REIT, from 2001 until it was sold to an affiliate of ING Clarion in May 2007. In addition, Mr. Knight served as Chairman and Chief Executive Officer of Cornerstone Realty Income Trust, Inc. from 1993 until it merged with a subsidiary of Colonial Properties Trust in 2005. Following that merger in 2005 and until April 2011, Mr. Knight served as a trustee of Colonial Properties Trust. Cornerstone Realty Income Trust, Inc. owned and operated apartment communities in Virginia, North Carolina, South Carolina, Georgia and Texas. Mr. Knight is the founding Chairman of Southern Virginia University in Buena Vista, Virginia. He also is a member of the Advisory Board to the Graduate School of Real Estate and Urban Land Development at Virginia Commonwealth University. Additionally, he serves on the National Advisory Council for Brigham Young University and is a founding member of the University's Entrepreneurial Department of the Graduate School of Business Management. On February 12, 2014, Mr. Knight, Apple Seven, Apple Eight, Apple REIT Nine, Inc. ("Apple Nine") and their related advisory companies entered into settlement agreements with the SEC. Along with Apple Seven, Apple Eight, Apple Nine and their advisory companies, and without admitting or denying the SEC's allegations, Mr. Knight consented to the entry of an administrative order, under which Mr. Knight and the noted companies each agreed to cease and desist from committing or causing any violations of Sections 13(a), 13(b)(2)(A), 13(b)(2)(B), 14(a), and 16(a) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") and Rules 12b-20, 13a-1, 13a-13, 13a-14, 14a-9, and 16a-3 thereunder.

David S. McKenney. Mr. McKenney has been part owner of and the Chief Financial Officer of the General Partner since its formation in December 2016. Mr. McKenney is also a part owner of and the Chief Financial Officer of Energy 11 GP, LLC, the general partner of Energy 11, a partnership also focused on investments in the oil and gas industry. Mr. McKenney also serves as Senior Advisor for Apple Hospitality REIT, Inc., a real estate investment trust. Mr. McKenney was the President of Capital Markets of Apple REIT Ten, Inc. from its inception until it merged with Apple Hospitality REIT, Inc. in September 2016. Mr. McKenney previously served as President of Capital Markets for Apple Hospitality REIT, Inc. In addition, Mr. McKenney was the President of Capital Markets of Apple REIT Six, Inc., a real estate investment trust, from 2004 until the company merged with an affiliate of Blackstone Real Estate Partners VII in May 2013. Mr. McKenney served in the same capacity for Apple Hospitality Five, Inc., a lodging REIT, from 2002 until the company was sold to Inland American Real Estate Trust, Inc. in October of 2007, and Apple Hospitality Two, Inc., a lodging REIT, from 2001 until the company was sold to an affiliate of ING Clarion in May of 2007. From 1994 to 2001, Mr. McKenney served as Senior Vice President and Treasurer of Cornerstone Realty Income Trust, Inc., a REIT that owned and operated apartment communities in Virginia, North Carolina, South Carolina, Georgia and Texas. From 1992 to 1994, Mr. McKenney served as Chief Financial Officer for The Henry A. Long Company, a regional development firm located in Washington, D.C. From 1988 to 1992, Mr. McKenney served as a Controller at Bozzuto & Associates, a regional developer of apartments and condominiums in the Washington, D.C. area. Mr. McKenney holds Bachelor of Science degrees in Accounting and Management Information Systems from James Madison University.

The General Partner

The General Partner is Energy Resources 12 GP, LLC, which was formed in 2016 and has no operating history. The General Partner was formed and is owned by companies controlled by Glade M. Knight and David S. McKenney.

The General Partner will receive a management fee for acting as general partner, as defined below. The Partnership has or will reimburse the General Partner for all third-party costs incurred and paid by the General Partner in connection with the formation of the Partnership, including third-party legal, accounting, printing, filing fees, travel and similar third party costs and expenses. In addition, the Partnership has or will reimburse the General Partner and its affiliates for all general and administrative expenses incurred by the General Partner and its affiliates in managing the Partnership's business. These costs and expenses will include the direct and indirect costs and expenses of employee compensation, rental, office supplies, travel and entertainment, printing, legal, accounting, advertising, marketing and overhead. The beneficial owners of the General Partner will not be employees of the General Partner, and will not receive salary or other compensation from the General Partner or the Partnership other than the reimbursement of third-party costs and expenses, the management fee described below, and with respect to their equity interests in the Partnership.

As described in the Prospectus, upon the Partnership's first property acquisition, the Partnership is obligated to pay quarterly an annual management fee of 0.5% of the total gross equity proceeds raised in this offering to the General Partner. The fees and expenses paid to the general partner will be in exchange for:

- Administering the day-to-day operations of the Partnership and performing or supervising the various administrative functions necessary to manage the Partnership;
- Identifying producing and non-producing properties for potential acquisition, and evaluating, contracting for and acquiring these properties and managing the development of these properties; and
- Monitoring or hiring a third party to monitor the operator(s) of the properties the Partnership acquires, including recommending whether the Partnership should participate in the development of such properties by the operators of the properties.

With the Partnership's closing on the purchase of certain non-operated oil and gas properties in North Dakota on February 1, 2018, the Partnership will begin payment of the management fee at the end of the first quarter of 2018.

Code of Ethics

The General Partner has adopted a Code of Business Conduct and Ethics that applies to the executive officers of the General Partner and other persons performing services for the General Partner and the Partnership, generally. This Code of Business Conduct and Ethics is posted on the Partnership's website at www.energyresources12.com.

Audit and Compensation Committee

The Partnership does not have a formal compensation committee and the Board of Directors of the General Partner serves as the audit committee. Because the Partnership does not have and is not seeking to list any securities on a national securities exchange or on an inter-dealer quotation system, the Partnership is not subject to a number of the corporate governance requirements of the SEC or of any national securities exchange or inter-dealer quotation system. For example, the Partnership is not required to have a board of directors comprised of a majority of independent directors or to have an audit committee comprised of independent directors. Accordingly, the Board of Directors has not made any determination as to whether any of the member of the Board of Directors would qualify as independent under the listing standards of any national securities exchange or any inter-dealer quotation system or under any other independence definition. Additionally, for the same reason, the Partnership has not yet determined whether any of the directors is an audit committee financial expert.

Item 11. Executive Compensation

The Partnership does not directly employ any of the persons responsible for managing its business. Instead, the General Partner manages the Partnership's day-to-day affairs and provides the Partnership with management and operating services. The members of the General Partner will be reimbursed for documented out-of-pocket travel, entertainment and similar expenses incurred by them in connection with managing the Partnership's business. The owners of the General Partner did not receive any salary, bonus or consulting fees for serving on the board of directors or for managing the Partnership's business for the year ended December 31, 2017. In addition, the members of the General Partner will not receive any salary, bonus or consulting fees for serving on the board of directors or for managing the Partnership's business, other than the annual management fee of 0.5% of the total gross equity proceeds raised in the Partnership's ongoing public offering (paid quarterly subsequent to the Partnership's first property acquisition) and distributions in accordance with the incentive distribution rights and their ownership of common units, if any.

Outstanding Equity Awards at Fiscal Year-End

There were no outstanding equity awards for the Partnership's named executive officers as of December 31, 2017, other than the Incentive Distribution Rights.

Compensation of Directors

The members of the General Partner do not receive compensation for their services as directors, aside from the management fee described in section "The General Partner" in Part III, Item 10 of this Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The following table sets forth as of February 22, 2018 the beneficial ownership of the common units that are owned by:

all persons who, to the knowledge of the management team, beneficially own more than 5% of the Partnership's common units;
each executive officer of the General Partner; and
all current directors and executive officers of the General Partner as a group.

Name of Beneficial Owner	Common Units Beneficially Owned	Percentage of Common Units Beneficially Owned
Glade M. Knight 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*
David S. McKenney 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*
Directors and executive officers of the General Partner as a group	10,000	*

* Less than 1% of outstanding common units.

Ownership of the General Partner

The General Partner is a limited liability company. The members of the General Partner and the membership interest owned are as follows:

GKOG, LLC, owns a 50% membership interest in the General Partner. GKOG, LLC is a limited liability company wholly owned by Mr. Knight.
DMOG, LLC owns a 50% membership interest in the General Partner. DMOG, LLC is a limited liability company wholly owned by Mr. McKenney.

Each member of the General Partner has the right to appoint one person to the General Partner's Board of Directors. All decisions regarding the business of the General Partner and the Partnership will be made by the Board of Directors of the General Partner at meetings of the Board of Directors at which a quorum is present. The presence of a majority of the directors constitutes a quorum, and the vote of a majority of a quorum constitutes a decision by the Board of Directors.

The owners of the members of the General Partner have granted each other the right of first refusal to acquire any interests in the members of the General Partner that the owners propose to sell. If the owners of the members of the General Partner do not exercise the right of first refusal, the purchaser of the owner of the General Partner will have the right to appoint a member to the board of directors, and if a person or group of affiliated persons were to acquire a controlling interest in both of the owners of the General Partner, the person would be able to control the General Partner and the Partnership. The Partnership Agreement does not give the holders of common units the right to cause an owner of the General Partner to exercise its buy-sell right, or provide the holders the right to consent to or otherwise approve the transfer by an owner of the General Partner of its membership interest in the General Partner. The General Partner does, however, agree not to permit a change of control of the General Partner to occur. A change of control is defined as a person who is not currently a beneficial owner of the General Partner or a "qualifying owner" becoming the beneficial owner of 50% or more of the membership interest in the General Partner. A qualifying owner generally is defined as the following with respect to the current beneficial owners of the General Partner: conservators, guardians, executors, administrators, and similar persons of any trust, private foundation or custodianship that such beneficial owner, his spouse, lineal descendants or estate is a beneficiary.

Securities Authorized for Issuance under Equity Compensation Plans

The Partnership does not have any equity compensation plans.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Reimbursement of Expenses to General Partner in Connection with Offering Costs

The Partnership Agreement provides that the General Partner is entitled to be reimbursed out of capital contributions for offering and organization costs paid to third parties, including legal, accounting, engineering, printing and filing fees.

Reimbursement of Expenses to General Partner in Connection with Operations of the Partnership

The Partnership will also reimburse the General Partner and the General Partner's affiliates for their General and administrative costs allocable to the Partnership. These expenses will include compensation expense, rent, travel, and other general and administrative and overhead expenses. Currently, the only business of the General Partner is to act as General Partner of the Partnership, and all of the General Partner's general and administrative costs will be paid by the Partnership. If affiliates of the General Partner form other partnerships or engage in other oil and gas activities, the General Partner will allocate its general and administrative costs to the Partnership and other partnerships or businesses in a manner deemed reasonable by the General Partner.

During the year ended December 31, 2017, approximately $57,000 of related party costs were incurred by a member of the General Partner and have been or will be reimbursed by the Partnership in connection with its operations.

Advisory and Administration Agreement with Regional Energy Investors, LP

The Partnership has engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting the Buyer through closing and post-closing of the Purchase Agreement. The Partnership will pay REI a total of approximately $5.3 million for its advisory and consulting services. REI is also entitled to a fee of 5% of the gross sales price in the event the Buyer disposes any or all of the Bakken Assets, if surplus funds are available after Payout to the holders of the Partnership's common units, as defined in Note 4. Capital Contributions and Partners' Equity of Part II, Item 8 of this Form 10-K. REI is owned by entities that are controlled by Anthony F. Keating, III, Co-Chief Operating Officer of Energy 11 GP, LLC, and Michael J. Mallick, Co-Chief Operating Officer of Energy 11 GP, LLC. As noted above, Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of Energy 11 GP, LLC as well as the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner.

Cost Sharing Agreement

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy 11, L.P. ("Energy 11") to provide access to Energy 11's personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for the Partnership. The shared day-to-day costs will be split evenly between the two partnerships and any direct third-party costs will be paid by the party receiving the services. The shared costs will be based on actual costs incurred with no mark-up or profit for Energy 11. The agreement may be terminated at any time by either party upon 60 days written notice. The officers and members of the Partnership's General Partner are also officers and members of the general partner of Energy 11.

Incentive Distribution Rights

On the initial closing date, the Partnership issued incentive distribution rights, which are non-voting limited partner interests that entitle the holder of such rights, after Payout occurs, to 30% of all amounts distributed until the Managing Dealer receives 4% of the gross proceeds of the common units sold, and to 60% of all amounts distributed thereafter, to the General Partner.

Director Independence

Because the Partnership does not have a class of securities listed on any national securities exchange, national securities association or inter-dealer quotation system, the Partnership is not required to have a board of directors comprised of a majority of independent directors under SEC rules or any listing standards. Accordingly, the Board of Directors of the General Partner has not made any determination as to whether any non-employee directors satisfy any independence requirements applicable to board members under the rules of the SEC or any national securities exchange, inter-dealer quotation system or any other independence definition.

Item 14. Principal Accountant Fees and Services

Ernst & Young LLP ("EY"), as the Partnership's independent registered public accounting firm, has audited the Partnership's consolidated financial statements for the most recent fiscal year ended December 31, 2017, and for the period from December 30, 2016 (initial capitalization) to December 31, 2016. For the year ended December 31, 2017, fees paid or payable to EY for services performed in connection with the audit of the 2017 financial statements, the audit of the financial statements for the period from December 30, 2016 (initial capitalization) to December 31, 2016, reviews of S-1s and any amendments, SEC comment letters, acquisition audits, issuance of consents and 2017 interim reviews are as follows:

	Year ended December 31, 2017
Audit fees	$ 145,000
Audit-related fees	40,000
Tax fees	-
All other fees	-
Total	$ 185,000

Pre-Approval Policies and Procedures

The General Partner currently has no Board committees. The Board of Directors has adopted policies regarding the pre-approval of auditor services. Specifically, the Board of Directors approves all services provided by the independent public accountants and reviews the actual and budgeted fees for the independent public accountants periodically at regularly scheduled meetings. All of the services provided by EY during fiscal 2017 were approved by the Board of Directors.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a) Documents filed as part of this report:

1. Financial Statements:

(i) Report of Independent Registered Public Accounting Firm – Ernst & Young LLP

(ii) Consolidated Balance Sheets as of December 31, 2017 and December 31, 2016

(iii) Consolidated Statements of Operations for the year ended December 31, 2017 and for the period from December 30, 2016 (initial capitalization) to December 31, 2016

(iv) Consolidated Statements of Partners' Equity for the year ended December 31, 2017 and for the period from December 30, 2016 (initial capitalization) to December 31, 2016

(v) Consolidated Statements of Cash Flows for the year ended December 31, 2017 and for the period from December 30, 2016 (initial capitalization) to December 31, 2016

(vi) Notes to Consolidated Financial Statements

2. Financial Statement Schedules:

(i) All schedules are omitted as they are not applicable, not required or the required information is included in the consolidated financial statements or notes thereto.

3. Exhibits:

The following exhibits are included, or incorporated by reference, in this Annual Report on Form 10-K, for the year ended December 31, 2017 (and are numbered in accordance with Item 601 of Regulation S-K). Exhibits incorporated by reference to this Form 10-K as listed below are available at www.sec.gov.

Exhibit No.	Description
1.1	Exclusive Dealer Manager Agreement with David Lerner Associates, Inc. (incorporated by reference from Exhibit 1.1 to Pre-Effective Amendment No. 1 to the Partnership's Registration Statement on Form S-1 filed on April 18, 2017).
2.1	Purchase and Sale Agreement dated November 21, 2017 by and between Energy Resources 12 Operating Company, LLC, as Purchaser, and Bruin E&P Non-Op Holdings, LLC, as Seller (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed on November 22, 2017).
3.1	Certificate of limited partnership of Energy Resources 12, L.P. (incorporated by reference from Exhibit 3.1 to the Partnership's Registration Statement on Form S-1 filed on March 23, 2017).
3.2	First Amended and Restated Limited Partnership Agreement of Energy Resources 12, L.P. (incorporated by reference from Exhibit A to the Prospectus included as part of Post-Effective Amendment No. 1 to the Partnership's Registration Statement on Form S-1 filed on February 1, 2018).
10.1	Form of Subscription Agreement (incorporated by reference from Exhibit B to the Prospectus included as part of Post-Effective Amendment No. 1 to the Partnership's Registration Statement on Form S-1 filed on February 1, 2018).
10.2	Advisory and Administration Agreement dated November 21, 2017 by and between Energy Resources 12 Operating Company, LLC, Energy Resources 12, L.P., and Regional Energy Investors, LP (incorporated by reference from Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on November 22, 2017).
10.3	Loan Agreement between Bank of America, N.A. and Energy Resources 12, L.P. dated January 16, 2018 (incorporated by reference from Exhibit 10.1 to the Partnership's form 8-K filed on January 17, 2018).
10.4	Cost Sharing Agreement between Energy Resources 12, L.P., Energy 11, L.P. and Energy 11 Management, LLC, dated January 31, 2018 (incorporated by reference from Exhibit 10.7 to Post-Effective Amendment No. 1 to the Partnership's Registration Statement on Form S-1 filed on February 1, 2018).
21.1	Subsidiaries of the Partnership*
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002*
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002*
32.1	Certification of Chief Executive Officer Pursuant to Section 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
32.2	Certification of Chief Financial Officer Pursuant to Section 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
101	The following materials from Energy Resources 12, L.P.'s Annual Report on Form 10-K for the year ended December 31, 2017 formatted in XBRL (eXtensible Business Reporting Language): (i) the Balance Sheets, (ii) the Statements of Operations, (iii) the Statement of Cash Flows, and (iv) related notes to these financial statements, tagged as blocks of text and in detail*

*Filed herewith.

Item 16. Form 10-K Summary

None

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ENERGY RESOURCES 12, L.P.

By: Energy Resources 12 GP, LLC, its General Partner

By: /s/ David S. McKenney
David S. McKenney
Chief Financial Officer

Date: February 26, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the Registrant and in the capacities and on the dates indicated.

Signature	Title with General Partner	Date
/s/ Glade M. Knight Glade M. Knight	Director, Chief Executive Officer (principal executive officer)	February 26, 2018
/s/ David S. McKenney David S. McKenney	Director, Chief Financial Officer (principal financial and accounting officer)	February 26, 2018

EXHIBIT 21.1

Subsidiaries of the Partnership

The following are wholly owned subsidiaries of Energy Resources 12, L.P.:

Energy Resources 12 Operating Company, LLC (Formed in Delaware)

EXHIBIT 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER PURSUANT TO RULE 13a-14(a)/15D-14(a)

I, Glade M. Knight, certify that:

1. I have reviewed this Annual Report on Form 10-K of Energy Resources 12, L.P. (the "registrant");

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

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

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

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

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

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

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

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

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

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

Date: February 26, 2018

By: /s/ Glade M. Knight
Name: Glade M. Knight
Title: General Partner, Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

CERTIFICATION OF CHIEF FINANCIAL OFFICER PURSUANT TO RULE 13a-14(a)/15D-14(a)

I, David S. McKenney, certify that:

1. I have reviewed this Annual Report on Form 10-K of Energy Resources 12, L.P. (the “registrant”);

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) for the registrant and have:

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

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

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

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

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

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

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

Date: February 26, 2018	By:	/s/ David S. McKenney
	Name:	David S. McKenney
	Title:	General Partner, Chief Financial Officer (Principal Financial and Accounting Officer)

EXHIBIT 32.1

CERTIFICATION FURNISHED PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

This certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and accompanies the Annual Report on Form 10-K (the "Form 10-K") for the year ended December 31, 2017 of Energy Resources 12, L.P. (the "Partnership"). I, Glade M. Knight, the Chief Executive Officer of the Partnership, certify that, based on my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Partnership as of and for the periods covered in this report.

Date: February 26, 2018

By: /s/ Glade M. Knight
Name: Glade M. Knight
Title: General Partner, Chief Executive Officer (Principal Executive Officer)

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Partnership, whether made before or after the date hereof, regardless of any general incorporation language in such filing.

EXHIBIT 32.2

CERTIFICATION FURNISHED PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

This certification is furnished solely pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (18 U.S.C. 1350) and accompanies the Annual Report on Form 10-K (the “Form 10-K”) for the year ended December 31, 2017 of Energy Resources 12, L.P. (the “Partnership”). I, David S. McKenney, the Chief Financial Officer of the Partnership, certify that, based on my knowledge:

(1) The Form 10-K fully complies with the requirements of Section 13(a) or Section 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of the Partnership as of and for the periods covered in this report.

Date: February 26, 2018	By:	/s/ David S. McKenney
	Name:	David S. McKenney
	Title:	General Partner, Chief Financial Officer (Principal Financial and Accounting Officer)

The foregoing certification is being furnished as an exhibit to the Form 10-K pursuant to Item 601(b)(32) of Regulation S-K and Section 906 of the Sarbanes-Oxley Act of 2002 (subsections (a) and (b) of Section 1350, Chapter 63 of Title 18, United States Code) and, accordingly, is not being filed as part of the Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and is not incorporated by reference into any filing of the Partnership, whether made before or after the date hereof, regardless of any general incorporation language in such filing.