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

FORM 10-K

þ **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: **000-55615**

ENERGY 11, L.P.
(Exact name of Registrant as specified in its charter)

Delaware	**46-3070515**
(State or other jurisdiction of incorporation)	(I.R.S. Employer Identification Number)
120 W 3rd Street, Suite 220 **Fort Worth, Texas**	**76102**
(Address of principal executive office)	(Zip Code)

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

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 Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☑ No ☐

Indicate by check mark 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, 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 by 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 March 8, 2018, the Partnership had 18,973,474 common units outstanding.

ENERGY 11, L.P.

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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 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 acquire properties, that the Partnership’s 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 11, L.P. (the "Partnership") is a Delaware limited partnership formed to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership completed its best-efforts offering on April 24, 2017 with a total of approximately 19 million common units sold for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

As of December 31, 2017, the Partnership owns an approximate 26-27% non-operated working interest in 215 currently producing wells, 6 wells currently being drilled and approximately 247 future development sites in the Sanish field located in Mountrail County, North Dakota (collectively, the "Sanish Field Assets"). Substantially all of the Sanish Field Assets are operated by Whiting Petroleum Corporation ("Whiting") (NYSE: WLL), a publicly traded oil and gas company and one of the largest producers in the basin.

The general partner of the Partnership is Energy 11 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, 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 – 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 used to acquire the Sanish Field Assets and develop these assets.

Current Developments

Oil and Gas Investments

On December 18, 2015, the Partnership completed its purchase ("Acquisition No. 1") of an approximate 11% non-operated working interest in the Sanish Field Assets for approximately $159.6 million. The Partnership accounted for Acquisition No. 1 as a business combination, and therefore expensed, as incurred, transaction costs associated with this acquisition. These costs included, but were not limited to, due diligence, reserve reports, legal and engineering services and site visits. The Sanish Field Assets are a part of the Bakken shale formation, which is one of the largest oil fields in the United States, in the Greater Williston Basin in northwest North Dakota.

On January 11, 2017, the Partnership completed its purchase ("Acquisition No. 2") of an additional approximate 11% non-operated working interest in the Sanish Field Assets for approximately $128.5 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 2 with the delivery of a promissory note in favor of the sellers of $40.0 million, which was paid in full in February 2017. The Partnership accounted for Acquisition No. 2 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the year ended December 31, 2017 were approximately $43,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.8 million in conjunction with this acquisition. Acquisition No. 2 increased the Partnership's non-operated working interest in the Sanish Field Assets from approximately 11% to approximately 22-23%.

On March 31, 2017, the Partnership completed its purchase ("Acquisition No. 3") of an additional approximate average 10.5% non-operated working interest in 82 of the Partnership's then 216 existing producing wells and 150 of the Partnership's then 253 future development locations in the Sanish Field Assets for approximately $52.4 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 3 with a promissory note in favor of the sellers of $33.0 million, which was paid in full on November 21, 2017. The Partnership accounted for Acquisition No. 3 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the year ended December 31, 2017 were approximately $80,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.3 million in conjunction with this acquisition. Acquisition No. 3 increased the Partnership's total non-operated working interest in the Sanish Field Assets to the current total of approximately 26-27%.

In October and November 2017, the Partnership elected to participate in the drilling and completion of six new wells. Four of the six wells are being drilled and operated by Oasis Petroleum, Inc. (NYSE: OAS), and the Partnership will have an estimated approximate 7-9% non-operated working interest in these four wells. The other two wells are being drilled and will be operated by Whiting, and the Partnership will have an estimated approximate 29% non-operated working interest in these two wells. The six wells were started in late 2017 and are anticipated to be completed in the first half of 2018. In the fourth quarter of 2017, the Partnership incurred approximately $1.3 million in capital expenditures for the drilling and completion of these six wells. The Partnership estimates the remaining capital expenditures to complete these six wells to be approximately $5.7 million.

Revolving Credit Facility

On November 21, 2017, the Partnership, as the borrower, entered into a loan agreement (the “Loan Agreement”) with Bank SNB (the “Lender”), which provides for a revolving credit facility (the “Credit Facility”) with an approved initial commitment amount of $20 million (the “Revolver Commitment Amount”), subject to borrowing base restrictions. The commitment amount may be increased up to $75 million with Lender approval. The Partnership paid an origination fee of 0.30% of the Revolver Commitment Amount, or $60,000, and is subject to additional origination fees of 0.30% for any borrowings made in excess of the Revolver Commitment Amount. The Partnership is also required to pay an unused facility fee of 0.50% on the unused portion of the Revolver Commitment Amount, based on the amount of borrowings outstanding during a quarter. The maturity date is November 21, 2019.

Under the Loan Agreement, the initial borrowing base is $30 million. However, the borrowing base is subject to redetermination semi-annually based upon the Lender’s analysis of the Partnership’s proven oil and natural gas reserves. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time. The interest rate, subject to certain exceptions, is equal to the London Inter-Bank Offered Rate (LIBOR) plus a margin ranging from 2.50% to 3.50%, depending upon the Partnership’s borrowing base utilization, as calculated under the terms of the Loan Agreement.

At closing, the Partnership borrowed $20.0 million. The proceeds were used to repay closing costs, the $5.9 million outstanding balance of the promissory note executed in conjunction with Acquisition No. 3 discussed above, and the $1.0 million deferred purchase price due to the seller in conjunction with Acquisition No. 1. The Credit Facility will provide additional liquidity for capital investments, including the drilling and completion of the six wells described above, and other corporate working capital requirements.

See further discussion of the Credit Facility in Part II, Item 7 – Management’s Discussion and Analysis of Financial Condition and Results of Operations and Note 4 titled “Debt” in Part II, Item 8 – Financial Statements and Supplementary Data, appearing elsewhere in this Annual Report on Form 10-K.

Hedging Contracts

In December 2017, the Partnership entered into derivative contracts to manage the commodity price risk on future oil production and to reduce the effect of volatility in commodity price changes to provide a base level of cash flow from operations. The table below summarizes the Partnership’s outstanding derivative contracts (costless collars – purchased put options and written call options) on the Partnership’s 2018 oil production.

	Costless Collar Volumes (Bbl)	**Weighted Average Floor / Ceiling Prices ($)**
2018	330,000	52.33 / 57.52

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 will oversee and review 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.

Regional Energy Investors, LP

In November 2017, Energy Resources 12, L.P. ("ER12"), a limited partnership that also invests in producing and non-producing oil and gas properties on-shore in the United States, engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting ER12 through closing and post-closing on the purchase of certain oil and gas properties in North Dakota. REI is owned by entities that are controlled by Anthony F. Keating, III and Michael J. Mallick, Co-Chief Operating Officers of the Partnership. Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner as well as the Chief Executive Officer and Chief Financial Officer, respectively, of Energy Resources 12 GP, LLC, the general partner of ER12.

Cost Sharing Agreement

On January 31, 2018, the Partnership entered into a cost sharing agreement with ER12 that will give ER12 access to the Partnership's personnel and administrative resources, including accounting, asset management and other day-to-day management support. 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 to the Partnership. The agreement may be terminated at any time by either party upon 60 days written notice.

See further discussion of transactions with related parties in Note 9 titled "Related Parties" in Part II, Item 8 – Financial Statements and Supplementary Data, appearing elsewhere in this Annual Report on Form 10-K.

Partners' Equity and Distributions

The Partnership completed its best-efforts offering of common units on April 24, 2017. As of the conclusion of the offering on April 24, 2017, the Partnership had completed the sale of approximately 19.0 million common units for total gross proceeds of $374.2 million and proceeds net of offerings costs of $349.6 million. David Lerner Associates, Inc. was the dealer manager for the Partnership's best-efforts offering (the "Dealer Manager"). Under the agreement with the Dealer Manager, the Dealer Manager received a total of 6% in selling commissions and marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, 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 in the offering, the total contingent fee is a maximum of approximately $15.0 million, which will only be paid if Payout occurs, as 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 (owned by the General Partner), with respect to Class B units or the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout 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, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest (currently 43.125%).

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 $1.361643 per common unit or $24.6 million. Effective with the November 29, 2017 distribution, the General Partner approved an adjustment to the annualized distribution rate to an annualized return of six percent based on a limited partner's Net Investment Amount of $20.00 per common unit. The difference between any distribution and an annualized return of seven percent based on the Net Investment Amount is required to be paid before final Payout occurs as defined above. As of December 31, 2017, the unpaid Payout Accrual totaled $0.034521 per common unit, or approximately $0.7 million. For the year ended December 31, 2016, the Partnership paid distributions of $1.400000 per common unit or $10.4 million.

Oil and Natural Gas Reserves

The table below summarizes our estimated net proved reserves as of December 31, 2017:

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MBOE)	Standardized Measure (2) (in thousands)
Proved Reserves (1)					
Developed	9,641	11,300	1,975	13,499	$ 130,459
Undeveloped	8,151	8,925	1,560	11,199	55,446
Total Proved Reserves	17,792	20,225	3,535	24,698	$ 185,905

(1) The Partnership's proved reserves as of December 31, 2017 were calculated using oil and natural gas price parameters established by current SEC guidelines and accounting rules based on unweighted arithmetic average prices as of the first day of each of the twelve months ended on such date. The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2017 were $51.34 per barrel of oil and $2.98 per MMcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2017 were $44.84 per barrel of oil, $0.12 per MMcf of natural gas and $16.94 per barrel of NGL. See "Note 10 — Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)" in the accompanying notes to consolidated financial statements included elsewhere in this report for information concerning proved reserves.

(2) The standardized measure of discounted future net cash flows represents the estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation, in accordance with Accounting Standards Codification Topic 932 – Extractive Activities – Oil and Gas. Because the Partnership was formed as a limited partnership, the Partnership is not subject to federal taxes in the calculation of the standardized measure. In addition, there are no entity level or gross receipts taxes in North Dakota, where all Partnership wells are located, that would give rise to an additional state tax provision.

The table above represents estimates only. Reserves estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Furthermore, different reserve engineers may make different estimates of reserves and cash flow based on the same available data and these differences may be significant. Therefore, these estimates are not precise. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will most likely vary from those estimated. In addition, the Partnership may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond its control. Prices for oil or natural gas at December 31, 2017 are above the average calculated for 2017. Sustained higher prices will have a positive impact to the estimated quantities and present values of the Partnership's reserves; however, should prices decline, the estimated quantities and present values of the Partnership's reserves will be reduced.

Internal Controls Over Reserve Estimates and Qualifications of Technical Persons

The Partnership's policies and practices regarding internal controls over the recording of reserves is structured to objectively and accurately estimate its oil and gas reserves quantities and present values in compliance with rules, regulations and guidance provided by the SEC, as well as established industry practices used by independent engineering firms and the Partnership's peers, and in accordance with the SPE 2007 Standards promulgated by the Society of Petroleum Engineers. The Partnership engaged Pinnacle Energy Services, LLC ("Pinnacle Energy") to prepare the reserve estimates for all of the Partnership's assets for the year ended December 31, 2017 in this annual report. Pinnacle Energy founder J.P. Dick has over 30 years of experience in the oil and natural gas industry, with exposure to reserves and reserve related valuations and issues during that time, and is a Registered Professional Engineer in the states of Texas and Oklahoma. Further qualifications include a bachelor of science in petroleum engineering, extensive internal and external reserve training, and asset evaluation and management. In addition, Mr. Dick is an active participant in industry reserve seminars, professional industry groups and is a member of the Society of Petroleum Engineers.

The Partnership's controls over reserve estimates include engaging Pinnacle Energy as the Partnership's independent petroleum engineer. The Partnership provided information about its oil and natural gas properties, including production profiles, prices and costs, to Pinnacle Energy and they prepared estimates of the Partnership's reserves attributable to the Partnership's properties. All of the information regarding reserves in this annual report on Form 10-K is derived from the report of Pinnacle Energy, which is included as an exhibit to this annual report on Form 10-K.

The Partnership's President works closely with Pinnacle Energy to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process as well as to review properties and discuss the methods and assumptions used by Pinnacle Energy in their preparation of the year-end reserve estimates. The Partnership's President also reviews the methods and assumptions used by Pinnacle Energy in the preparation of year-end reserve estimates, and assesses them for reasonableness. The Board of Directors of the General Partner also meets with the Partnership's President to discuss matters and policies related to the Partnership's reserves.

The Partnership's methodologies include reviews of production trends, analogy to comparable properties, and/or volumetric analysis. Performance methods are preferred. Reserve estimates for proved undeveloped properties are based primarily on volumetric analysis or analogy to offset production in the same or similar fields. The Partnership applies and maintains internal controls, including but not limited to the following, to ensure the reliability of reserves estimations:

- no employee's compensation is tied to the amount of reserves booked;
- the Partnership follows comprehensive SEC-compliant internal policies to determine and report proved reserves;
- reserve estimates are made by experienced reservoir engineers or under their direct supervision;
- annual review by the Board of Directors of the General Partner of the Partnership's year-end reserve estimates prepared by Pinnacle Energy.
- semi-annually, the Board of Directors of the General Partner reviews all significant reserves changes and all new proved undeveloped reserves additions.

Proved Undeveloped Reserves

At December 31, 2017, the Partnership had proved undeveloped reserves ("PUDs") of approximately 11,199 MBOE, or approximately 45% of total proved reserves. Total PUDs at December 31, 2016 were 5,430 MBOE. The following table reflects the changes in PUDs during 2017:

	MBOE
Proved undeveloped reserves, December 31, 2016	5,430
Revisions of previous estimates (1)	(2,838)
Conversion to proved developed reserves (2)	(519)
Proved undeveloped reserves acquired (3)	9,126
Proved undeveloped reserves, December 31, 2017	11,199

(1) Revisions to previous estimates decreased Partnership PUDs by a net amount of 2,838 MBOE. The revision was the result of 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule, which were partially offset by 30 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the December 31, 2017 reserve estimates to prices used in the December 31, 2016 reserve estimates. There were no adjustments related to well performance.

(2) The Partnership is participating in the drilling and completion of six wells, which are in progress at December 31, 2017 (see "Oil and Gas Investments" above) and represent a conversion of 519 MBOE from the PUD category to proved developed for the year ended December 31, 2017.

(3) The Partnership acquired 5,430 MBOE and 3,696 MBOE of PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see "Oil and Gas Investments" above), for a total of 9,126 MBOE during the year ended December 31, 2017.

Under current SEC requirements, PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years of their date of original booking unless specific circumstances justify a longer time. The Partnership will be required to remove current PUDs if the Partnership does not drill those reserves within the required five-year time frame, unless specific circumstances justify a longer time. All of the Partnership's PUDs at December 31, 2017 are scheduled to be drilled within five years of the date they were initially recorded. However, since the Partnership is not the operator of any of its oil and natural gas properties, it is difficult to predict with certainty the timing of drilling and completion of wells currently classified as PUD reserves. Historically, energy commodity prices have been volatile, and due to geopolitical risks in oil producing regions of the world as well as global supply and demand concerns, the Partnership continues to expect significant price volatility. Sustained lower prices for oil and natural gas may cause the Partnership in the future to forecast less capital to be available for development of its PUDs, which may cause the Partnership to decrease the number of PUDs it expects to develop within the five-year time frame. In addition, lower oil and natural gas prices may cause the Partnership's PUDs to become uneconomic to develop, which would cause the Partnership to remove them from the proved undeveloped category.

Production, Prices and Production Cost History

The following table sets forth certain information regarding the production volumes, average prices received and average production costs associated with the sale of oil, natural gas, and natural gas liquids for the periods indicated below.

	Year Ended December 31,	
	2017	2016
Production (BOE):		
Oil	756,470	498,926
Natural gas	156,136	86,521
Natural gas liquids	161,845	69,059
Total	1,074,451	654,506
Average sales price per unit:		
Oil (per Bbl)	$ 44.31	$ 36.50
Natural gas (per Mcf)	3.15	2.43
Natural gas liquids (per Bbl)	28.07	12.97
Combined (per BOE)	38.17	31.12
Average unit cost per BOE:		
Production costs:		
Production expenses	$ 11.20	$ 8.88
Production taxes	3.17	2.86
Total production costs	14.37	11.74
Depreciation, depletion and amortization	14.04	14.56

Delivery Commitments

As of December 31, 2017, the Partnership had no commitments to deliver a fixed quantity of oil or natural gas.

Drilling Activity

In October and November 2017, the Partnership elected to participate in the drilling and completion of six new wells, which were started in the fourth quarter of 2017 and are anticipated to be completed in the first half of 2018. Four of these wells are being drilled and will be operated by Oasis, and the Partnership will have an estimated approximate 7-9% non-operated working interest in these four wells. The other two wells are being drilled and will be operated by Whiting, and the Partnership will have an estimated approximate 29% non-operated working interest in these two wells. The total cost to the Partnership for these wells is estimated to be approximately $7.0 million. All six wells are development wells.

During the first quarter of 2016, the Partnership completed the drilling of one well. No other wells were started or completed for the remainder of 2016.

Total Productive Wells

The following table sets forth information with respect to the Partnership’s ownership interest in productive wells as of December 31, 2017:

	December 31, 2017	
	Gross	Net
Oil wells:		
Sanish Field	216	55.5

Of the total well count for 2017, none are multiple completions.

Productive wells are producing wells and wells the Partnership deems mechanically capable of production, including shut-in wells, wells waiting for completion, plus wells that are drilled/cased and completed, but waiting for pipeline hook-up. At December 31, 2017, the Partnership had 215 currently producing wells and one shut-in well. A gross well is a well in which we own a working interest. The number of net wells represents the sum of fractional working interests the Partnership owns in gross wells.

Developed and Undeveloped Acreage Position

The following table sets forth information with respect to the Partnership's gross and net developed and undeveloped oil and natural gas acreage under lease as of December 31, 2017, all of which is located in the State of North Dakota in the United States:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Sanish Field, Mountrail County, ND	16,699	5,173	18,579	5,755	35,278	10,928

As is customary in the oil and natural gas industry, the Partnership can generally retain an interest in undeveloped acreage through drilling activity that establishes commercial production sufficient to maintain the leases or by paying delay rentals during the remaining primary term of leases. The oil and natural gas leases in which the Partnership has an interest are for varying primary terms and, if production under a lease continues from developed lease acreage beyond the primary term, the Partnership is entitled to hold the lease for as long as oil or natural gas is produced. The oil and natural gas properties consist primarily of oil and natural gas wells and interests in developed leasehold acreage.

Undeveloped Acreage Expirations

The Partnership has no undeveloped acreage expirations as all acreage is held by production.

Marketing and Customers

The market for the Partnership's oil and natural gas production depends on factors beyond its control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, the demand for oil and natural gas, the marketing of competitive fuels and the effect of state and federal regulation. The oil and natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Whiting, as operator of Partnership's properties, sells 99% of the Partnership's production on the Partnership's behalf.

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 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 11, L.P. is a Delaware limited partnership founded in 2013 with principal offices at 120 W 3rd Street, Suite 220, Fort Worth, Texas 76102. The Partnership's phone number is (817) 882-9192 and its website address is www.energyeleven.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 Partnership and the General Partner's 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 first oil and gas program in which the Partnership's chief executive officer and chief financial officer have participated. The Partnership, which was formed in 2013, has limited operating history, and since its formation, the Partnership has not owned or operated any operating assets other than the Sanish Field Assets first acquired on December 18, 2015, with subsequent acquisitions in January and March 2017. This is also the first oil and gas program sponsored by the General Partner and its affiliates. 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.

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.

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.

Distributions to the Partnership's common unitholders may not be sourced from its cash generated from operations but from 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. 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 the Partnership's 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.

Moreover, as a result of entering into the Credit Facility in November 2017, the Partnership will use a portion of its cash flow to pay interest on and principal of this indebtedness when due, which will reduce the cash available to finance the Partnership's operations and other business activities and could limit the Partnership's flexibility in planning for or reacting to changes in the Partnership's business and the industry in which it operates.

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, McKenney, Keating and Mallick, the executive officers of the General Partner. 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.

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 the incentive distribution rights held by the General Partner, which may cause it 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;
- Conflicts caused by the sale of properties to programs that have or may be formed by the General Partner and its affiliates in the future; and
- Conflicts caused by competition for management time and attention with other oil and gas partnerships and with other business activities in which management of the General Partner are or may be involved.

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.

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 have and will receive reimbursement of third-party costs incurred in connection with the Partnership's business activities and will be reimbursed for general and administrative costs of the General Partner allocable to the Partnership as described in "Compensation" within the Partnership's prospectus, 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 the cash available for distribution;"
- repayment of borrowings;
- drilling and completing new wells;
- cost overruns on drilling, completion or operating activities;
- remedial work to improve a well's producing capability;
- the acquisition of producing and non-producing oil and gas leasehold interests considered in the best interest of the Partnership by the General Partner;
- 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 the Partnership's public 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 the Partnership's properties or merge with another entity will be based on a number of factors, including the domestic and foreign supply of and demand for oil, natural gas and other hydrocarbons, commodity prices, demand for oil and natural gas assets in general, the value of the Partnership's assets, the projected amount of the Partnership's oil and gas reserves, general economic conditions and other factors that are out of the Partnership's control. In addition, the ability to list the Partnership's common units on a national securities exchange will depend on a number of factors, including the state of the U.S. securities markets, the Partnership's ability to meet the listing 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 lack of geographical diversification may increase the risk of an investment in the Partnership.

All of the Partnership's assets are located in concentrated areas of the Williston Basin in Mountrail County, North Dakota. While other companies and limited partnerships may have the ability to manage their risk by diversification, the narrow geographic focus of the Partnership's business means that it may be impacted more acutely by factors affecting its industry or the region in which the Partnership operates than it would if its asset locations were more diversified. The Partnership may be disproportionately exposed to the effects of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, weather events or interruption of the processing or transportation of oil or natural gas. Additionally, the Partnership may be exposed to further risks, such as changes in field-wide rules and regulations that could cause the Partnership to permanently or temporarily shut-in all of its wells within the Williston Basin. The Partnership does not currently intend to broaden the geographic scope of its asset base.

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.

In November 2017, the Partnership entered into a Credit Facility, and restrictions in the Credit Facility 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 Credit Facility contains covenants limiting the Partnership's ability to make distributions, incur indebtedness, grant liens, make acquisitions, make investments or dispositions and engage in transactions with affiliates, as well as covenants requiring the Partnership to maintain certain financial ratios and tests. In addition, the borrowing base under the Partnership's Credit Facility is subject to periodic review by its lender. Difficulties in the credit markets may cause the banks to be more restrictive when redetermining the Partnership's borrowing base.

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.

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 directors, 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.

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 Energy 11 GP, LLC, 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 Dealer Manager regardless of success of the Partnership's activities will reduce the cash the Partnership has available for distribution.

The General Partner and its affiliates have and will receive reimbursement of third-party costs incurred in connection with 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 Dealer Manager is eligible to receive the contingent, incentive fee after Payout, as defined in the Prospectus. The fees and direct costs to be paid to the General Partner and the Dealer Manager will reduce the amount of cash distributions to investors.

Risks Related to the Partnership's Business

The Partnership has limited control over the activities on its properties.

At December 31, 2017, Whiting operates 99% of the properties in which the Partnership holds a working interest. The Partnership has limited ability to influence or control the operation or future development of the non-operated properties or the amount of capital expenditures that it is required to fund. The failure of Whiting to adequately perform operations, breach the applicable agreements or 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 Whiting and other working interest owners for these projects and the Partnership's 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 will need additional funding for the Sanish Field Assets in order to retain its full interest therein.

The Partnership anticipates that it will be obligated to significantly invest in drilling capital expenditures within the next five years to participate in drilling activity in the Sanish Field 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 increased cash flow from operations and its Credit Facility to fund the anticipated capital expenditures needed to retain its full interest in the Sanish Field Assets. None of these funding sources is guaranteed, and if the Partnership is unable to obtain all of this funding, it may lose all or a portion of the assets acquired, and the Partnership's results of operations will be negatively affected accordingly.

The Partnership may not have sufficient cash from operations following the establishment of cash reserves and payment of fees and expenses, including cost reimbursements 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:

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 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 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 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. 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, natural gas and other hydrocarbons;
- regulations which may prevent or limit the export of oil, natural gas and other hydrocarbons;
- the amount of added production from development of unconventional natural gas reserves;
- the price and quantity of foreign imports of oil, natural gas and other hydrocarbons;
- the level of consumer product demand;
- weather conditions and natural disasters;
- the value of the U.S dollar relative to the currencies of other countries;
- overall domestic and global economic conditions;
- 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, 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;
- technological advances affecting energy production and consumption;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the proximity and capacity of oil, natural gas and other hydrocarbon pipelines and other transportation facilities to its production;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas; and
- the price and availability of alternative fuels.

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

The Partnership owns less than 100% of the working interest in the Sanish Field Assets, and other parties 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 or entity. 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 the other working interest owners, particularly those that are smaller and less established, will not be 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.

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 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 the 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 we acquire;
- drilling, operating and other cost overruns;
- an inability to integrate successfully the properties the Partnership has or will acquire;
- the assumption of liabilities;
- limitations on rights to indemnity from the seller;
- the diversion of management’s attention from other business concerns; and
- losses of key employees.

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

The Partnership has acquired 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 has engaged in hedging transactions to reduce, but not eliminate, the effect of volatility in oil, gas and other hydrocarbon prices. These hedging transactions will expose the Partnership to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could 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, its ability to negate the risk may be limited depending upon market conditions.

During periods of falling commodity prices, such as those that occurred in late 2008 and 2012, the Partnership's hedge receivable positions will 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 has and 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 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 is 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 financial conditions of any hydrocarbon purchasers could have an adverse impact on the Partnership 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 plans to rely on drilling to fully develop the properties the Partnership has acquired. If drilling is unsuccessful, the Partnership's cash available for distributions and financial condition will be adversely affected.

The Partnership has acquired oil and gas properties that are not fully developed, and require that the Partnership engages in drilling to fully exploit the reserves attributable to the properties. The Partnership's drilling, completed by its operators, 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 any debt obligations.

The Partnership's 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. The Partnership's overall drilling success rate 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 its operations and financial condition by reducing available cash and resources.

The Partnership's continued success depends upon its ability to develop oil and gas reserves that are economically recoverable.

In addition, the Partnership's future oil and natural gas production will depend on the Partnership's success developing its assets to add to its reserves. If the Partnership is unable to replace reserves through drilling, 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 development activities. The Partnership's ability to make the necessary capital investment to maintain and 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 its assets to increase its reserves.

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 maintains 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.

The Partnership's financial condition and results of operations may be materially adversely affected if the Partnership incurs costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

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 the Partnership's 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 or operated by the Partnership 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 subject 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 its operations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, 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.

The Partnership is subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, 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 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 the Partnership's ability to develop its properties, and receipt of drilling permits with onerous conditions could increase the Partnership's compliance costs. In addition, regulations regarding resource conservation practices and the protection of correlative rights affect the Partnership's operations by limiting the quantity of oil, natural gas and natural gas liquids the Partnership may produce and sell.

The Partnership is 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.

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.

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. Some members of Congress have publicly indicated an intention to introduce legislation to curb the EPA's regulatory authority over GHGs. 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. 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 Partnership is an emerging growth company under the JOBS Act and it intends to take advantage of reduced disclosure and governance requirements applicable to emerging growth companies, which could result in the Partnership's common units being less attractive to investors.

The Partnership is an emerging growth company, as defined in the JOBS Act, and it intends to take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in the Partnership's periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved. The Partnership expects to continue to take advantage of these reporting exemptions until the Partnership is no longer an emerging growth company, which in certain circumstances could be for up to five years.

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

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.

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 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 us equal to your share of the Partnership's taxable income or even equal to the tax liability that results from that income.

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 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 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

Information regarding the Partnership's properties is contained in Item 1 – Business, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 8 – Financial Statements and Supplementary Data: Note 3. Oil and Gas Investments, appearing elsewhere within this Annual Report on Form 10-K.

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

As of December 31, 2017, there were approximately 19.0 million common units outstanding. As of March 8, 2018, the common units were held by approximately 4,800 limited partners. There is currently no established public trading market in which the Partnership’s common units are traded.

Solely to assist trustees and custodians of individual retirement accounts (“IRAs”) containing an investment in the Partnership’s common units and to assist broker-dealers in meeting their customer account statement reporting obligations under Financial Industry Regulatory Authority (“FINRA”) rules for investments in the Partnership, on January 23, 2018, the Partnership announced an estimated per common unit value of the Partnership’s common units as of December 31, 2017 of $17.15 per common unit, as further described below. There can be no assurance that this estimated value per common unit, or the method used to estimate such value, complies with requirements applicable to a trustee’s, custodian’s or broker-dealer’s obligations with respect to IRAs or FINRA’s reporting requirements.

The fair value estimate of the Partnership’s common units was based upon a third-party valuation, performed by Pinnacle Energy Services of Oklahoma City, Oklahoma, of the Partnership’s oil and natural gas properties and management’s estimate of the fair value of the Partnership’s other assets and liabilities as of December 31, 2017. The developed per common unit value range was $16.05- $19.30. The Partnership utilized the mid-point of the assumptions discussed below to determine the estimated value per common unit above. The following is a summary of the details of the fair value estimate:

(in thousands, except per common unit data)		**Estimate at 12/31/17**
Estimated fair value of oil and gas properties	$	331,301
Estimated fair value of cash and cash equivalents		11,091
Estimated fair value of other assets and liabilities, net		2,934
Estimated fair value of outstanding debt		(20,000)
Estimated fair value of equity	$	325,326
Common units outstanding		18,973
Estimated value per common unit	$	17.15

Since the Partnership’s common units are not listed on a national securities exchange, no material public market exists for the Partnership’s common units. As a result, although not prepared for generally accepted accounting purposes, the value estimate of the Partnership’s oil and gas properties was derived from unobservable inputs and was based on the income approach as outlined in Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) Topic 820, Fair Value Measurements and Disclosures. In the income approach, the estimated value of the Partnership’s oil and gas properties was calculated from a discounted cash flow model using consolidated projected cash flows of the Partnership’s reserves, as well as a discount rate based on market conditions at December 31, 2017. An additional market-based adjustment was made to reflect the probability of successful future development of the Partnership’s oil and gas reserves at December 31, 2017. The Partnership’s cash and cash equivalents are all highly liquid with maturities of three months or less and the fair market value approximates the carrying value. The Partnership’s other assets and liabilities include receivables from the sale of oil, natural gas and natural gas liquids, accounts payable and accrued expenses, which are short-term in nature, and the carrying value of these assets and liabilities approximates fair value at December 31, 2017. The carrying value of the Partnership’s outstanding debt was considered to approximate fair value at December 31, 2017 based on general market conditions and its maturity. The valuation methodology and calculations were reviewed by management of the Partnership and considered reasonable. The estimated value was not based on an appraisal of the Partnership’s assets.

As with any methodology used to estimate value, the methodology employed by the Partnership was based upon a number of estimates and assumptions that may not be accurate or complete and may not accurately reflect future conditions. The estimates and assumptions underlying the estimated value involve judgments with respect to, among other things, future economic, competitive, regulatory and financial market conditions and future business decisions which may not be realized and that are inherently subject to significant business, economic, competitive and regulatory uncertainties and contingencies, including, among others, risks and uncertainties described in the periodic reports filed by the Partnership with the Securities and Exchange Commission ("SEC"), all of which are difficult to predict and many of which are beyond the control of the Partnership. Further, different parties using different assumptions and estimates could derive a different estimated value per common unit, which could be significantly different from the Partnership's estimated value per common unit.

The estimated per common unit value does not represent: (i) the amount at which the Partnership's common units would trade on a national securities exchange, (ii) the amount a limited partner would obtain if he or she tried to sell his or her common units or (iii) the amount limited partners would receive if the Partnership liquidated its assets and distributed the proceeds after paying all expenses and liabilities. Accordingly, with respect to the estimated value per common unit, the Partnership can give no assurance that:

- a limited partner would be able to resell his or her common units at this estimated value;
- a limited partner would ultimately realize distributions per common unit equal to the estimated value per common unit upon liquidation of the Partnership's assets and settlement of its liabilities or a sale of the Partnership (in part because estimated values do not necessarily indicate the price at which individual assets or the Partnership could be sold, oil and gas property values fluctuate and change, and the estimated value may not take into account the expenses associated with such a sale);
- the Partnership's common units would trade at a price equal to or greater than the estimated value per common unit if they were listed on a national securities exchange;
- the methodology used to estimate the value per common unit would be acceptable to FINRA or for compliance with requirements applicable to a trustee's or custodian's obligations with respect to IRAs; or
- any or all of the assumptions used in estimating the value per common unit will prove to be accurate or complete.

The estimated value reflects the fact that the estimate was calculated as of a point in time. The value of the Partnership's common units will likely change over time and will be influenced by changes to the value of individual assets, changes in the oil and gas industry, as well as changes and developments in the energy and capital markets. The Partnership does not intend to update or otherwise revise the above information to reflect circumstances existing after the date when made or to reflect the occurrence of future events, even in the event that any or all of the assumptions underlying the information are no longer appropriate.

As discussed above, the estimated value of the Partnership's oil and gas properties was determined based on various market level assumptions, including but not limited to commodity market prices, discount rates and processing and transportation costs. The following is a list of key assumptions used in the calculation of the estimated value of the Partnership's oil and gas properties, a component of the estimated value per common unit:

- NYMEX oil strip pricing as of December 31, 2017, which ranges from $59.55 per barrel to $51.67 per barrel as of January 1, 2018 to December 31, 2022, and an increase of 3% thereafter with price cap at $100.00 per barrel
- NYMEX gas strip pricing as of December 31, 2017, which ranges from $2.83 per Mcf to $2.89 per Mcf as of January 1, 2018 to December 31, 2022, and an increase of 3% thereafter with price cap of $6.00 per Mcf
- Differentials to NYMEX strip pricing due to product processing, transportation or contract terms
    - $6.50 per barrel of oil
    - $2.86 per Mcf of natural gas
    - Natural gas liquids (NGL) determined using 33.0% of oil price
    - Natural gas shrink of 25.4%
    - NGL yield of 130.39 barrel per MMcf of wet gas
- Discount rate – 10.0%
- Risk adjustments to calculated present value
    - Proved developed producing (PDP) assets – 5.0%
    - Proved developed, not producing (PNP) assets (drilling in process, but not yet complete) – 10.0%
    - Proved undeveloped (PUD) assets to be drilled within five years – 20.0%
    - Proved undeveloped (PROB) assets to be drilled between five and ten years – 30.0%
    - Proved undeveloped (POSS) assets to be drilled after ten years – 40.0%

- Average well expenses estimated to scale down from $25,000 per well per month to $7,500 per well per month in year 13, then held constant at $6,800 per well per month starting in year 14 through end of well life
- Capital expenditures to drill and complete future development locations estimated at $6.4 million per well

A change in any of the assumptions would likely produce a different estimated value per common unit. For example:

- An increase in the discount rate assumption of 100 basis points would decrease the per common unit value range by approximately $0.87 per common unit, all other assumptions remaining the same;
- A decrease in the discount rate assumption of 100 basis points would increase the per common unit value range by approximately $2.16 per common unit, all other assumptions remaining the same;
- An increase of 500 basis points in the risk adjustment percentage to calculated present value per reserve category would decrease the per common unit value range by approximately $1.10 per common unit, all other assumptions remaining the same; and
- A decrease of 500 basis points in the risk adjustment percentage to calculated present value per reserve category would increase the per common unit value range by approximately $1.09 per common unit, all other assumptions remaining the same.

Class B Units

As of December 31, 2017 and 2016, the outstanding Class B units totaled 62,500. The Partnership may issue up to 37,500 additional Class B units. The Class B units provide for certain distribution rights described below.

Incentive Distribution Rights and Contingent Incentive Fee

The General Partner received the Incentive Distribution Rights upon closing of the minimum offering in August 2015. Under the agreement with the Dealer Manager, the Dealer Manager will be paid a contingent incentive fee, 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 total contingent fee is approximately $15.0 million. The Partnership will not make any distributions with respect to the Incentive Distribution Rights or the contingent, incentive payments to the Dealer Manager, until Payout occurs, as described below.

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 or with respect to Class B units and will not make the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout 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, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest (currently 43.125%).

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 $1.361643 per common unit or $24.6 million. Effective with the November 29, 2017 distribution, the General Partner approved an adjustment to the annualized distribution rate to an annualized return of six percent based on a limited partner's Net Investment Amount of $20.00 per common unit. The difference between any distribution and an annualized return of seven percent based on the Net Investment Amount is required to be paid before final Payout occurs as defined above. As of December 31, 2017, the unpaid Payout Accrual totaled $0.034521 per common unit, or approximately $0.7 million. For the year ended December 31, 2016, the Partnership paid distributions of $1.400000 per common unit or $10.4 million.

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

The Partnership was formed as a Delaware limited partnership. The General Partner is Energy 11 GP, LLC (the "General Partner"). The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership began offering common units of limited partner interest (the "common units") on a best-efforts basis on January 22, 2015, the date the Partnership's initial Registration Statement on Form S-1 (File No. 333-197476) was declared effective by the SEC. The Partnership completed its best-efforts offering on April 24, 2017. Total common units sold were approximately 19.0 million for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

As of December 31, 2017, the Partnership owns an approximate 26-27% non-operated working interest in 215 currently producing wells, 6 wells currently being drilled and approximately 247 future development sites in the Sanish field located in Mountrail County, North Dakota (collectively, the "Sanish Field Assets"). Substantially all of the Sanish Field Assets are operated by Whiting Petroleum Corporation ("Whiting") (NYSE: WLL), a publicly traded oil and gas company and one of the largest producers in the basin.

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 are made by the Board of Directors of the General Partner and its officers.

The Partnership was formed to acquire and develop oil and gas properties located onshore in the United States. On December 18, 2015, the Partnership completed its first purchase ("Acquisition No. 1") in the Sanish field, acquiring an approximate 11% non-operated working interest in the Sanish Field Assets for approximately $159.6 million. On January 11, 2017, the Partnership closed on its second purchase ("Acquisition No. 2") in the Sanish field, acquiring an additional approximate 11% non-operated working interest in the Sanish Field Assets for approximately $128.5 million. On March 31, 2017, the Partnership closed on its third purchase ("Acquisition No. 3") in the Sanish field, acquiring an additional approximate average 10.5% non-operated working interest in 82 of the Partnership's then 216 existing producing wells and 150 of the Partnership's then 253 future development locations in the Sanish Field Assets for approximately $52.4 million.

In October and November 2017, the Partnership elected to participate in the drilling and completion of six new wells, all of which were started in the fourth quarter of 2017 and are anticipated to be completed in the first half of 2018. Four wells are being drilled and will be operated by Oasis Petroleum, Inc., and the Partnership will have an estimated approximate 7-9% non-operated working interest rights in those four wells. The other two wells are being drilled and will be operated by Whiting, and the Partnership will have an estimated approximate 29% non-operated working interest rights in these two wells.

Current Price Environment

Oil, natural gas and natural gas liquids (“NGL”) prices are determined by many factors outside of the Partnership’s control.

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 declined throughout 2015 and in the first quarter of 2016, prices had fallen to the lowest levels since October 2003. The monthly average oil price per barrel reached a low of $30.32 in February 2016 and a high of $51.97 per barrel 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, from January 1, 2016 to December 31, 2017, natural gas prices fluctuated from a low of $1.73 per MMBtu in March 2016 to $3.59 per MMBtu in December 31, 2016. The monthly average natural gas price for December 2017 was $2.81 per MMBtu.

Factors contributing to world-wide commodity pricing volatility include real or perceived geopolitical risks in oil-producing regions of the world, particularly the Middle East; forecasted levels of global economic growth combined with forecasted global supply; supply levels of oil and natural gas due to exploration and development activities in the United States; actions taken by the Organization of Petroleum Exporting Countries; and the strength of the U.S. dollar in international currency markets. In addition to commodity price fluctuations, the Partnership faces the challenge of natural production volume declines. As reservoirs are depleted, oil and natural gas production from Partnership wells will decrease.

The following table lists average NYMEX prices for oil and natural gas for the years ended December 31, 2017 and 2016.

	Year Ended December 31, 2017	Year Ended December 31, 2016
Average market closing prices (1)		
Oil (per Bbl)	$ 50.92	$ 43.40
Natural gas (per Mcf)	$ 2.99	$ 2.52

(1) Based on average NYMEX futures closing prices (oil) and NYMEX/Henry Hub spot prices (natural gas)

Partnership revenues are highly sensitive to changes in oil and natural gas prices and to levels of production. Future growth is dependent on the Partnership’s ability to add reserves in excess of production. Dependent on available cash flow, the Partnership intends to seek opportunities to invest in its existing producing wells, drill new wells on existing leasehold sites like the six wells discussed above and/or acquire additional reserves.

As specified by the SEC, the prices for oil, natural gas and NGL used to calculate the Partnership’s reserves were the average prices during the years ended December 31, 2017 and 2016. The oil and natural gas prices used in computing the Partnership’s reserves as of December 31, 2017 were $51.34 per barrel of oil and $2.98 per MMcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership’s reserves as of December 31, 2017 were $44.84 per barrel of oil, $0.12 per MMcf of natural gas and $16.94 per barrel of NGL. The oil and natural gas prices used in computing the Partnership’s reserves as of December 31, 2016 were $42.75 per barrel of oil and $2.48 per thousand cubic feet (Mcf) of natural gas. The prices, after price differentials, were $36.25 per barrel of oil, ($0.38) per Mcf of natural gas and $4.70 per barrel of NGL. The gathering and processing contract in effect for the extraction, transportation and treatment of natural gas led to a price differential that exceeded the twelve-month average market price for natural gas, which results in an estimated negative average realized natural gas price utilized in the December 31, 2016 reserves calculation.

Results of Operations for Years 2017 and 2016

The Partnership closed on its first purchase (original approximate 11% working interest) of the Sanish Field Assets in December 2015, then completed its second purchase (approximate additional 11% working interest) and its third purchase (additional approximate 4-5% working interest) of the Sanish Field Assets on January 11, 2017 and March 31, 2017, respectively. The comparability of operating results for the years ended December 31, 2017 and 2016 are significantly impacted by these transactions.

	Years Ended December 31,			
	2017	Percent of Revenue	2016	Percent of Revenue
Total revenue	41,012,740	100.0%	20,365,338	100.0%
Production expenses	12,034,976	29.3%	5,811,111	28.5%
Production taxes	3,406,171	8.3%	1,870,212	9.2%
Depreciation, depletion, amortization and accretion	15,084,504	36.8%	9,526,865	46.8%
General, administration and other expense	909,326	2.2%	2,254,909	11.1%
Production (BOE):				
Oil	756,470		498,926	
Natural gas	156,136		86,521	
Natural gas liquids	161,845		69,059	
Total	1,074,451		654,506	
Average sales price per unit:				
Oil (per Bbl)	$ 44.31		$ 36.50	
Natural gas (per Mcf)	3.15		2.43	
Natural gas liquids (per Bbl)	28.07		12.97	
Combined (per BOE)	38.17		31.12	
Average unit cost per BOE:				
Production expenses	11.20		8.88	
Production taxes	3.17		2.86	
Depreciation, depletion and amortization	14.04		14.56	

Oil, Natural Gas and NGL Sales

For the years ended December 31, 2017 and 2016, revenues for oil, natural gas and NGL sales were $41.0 million and $20.4 million, respectively. Revenues for the sale of oil were $33.5 million and $18.2 million, which resulted in realized prices of $44.31 and $36.50 per barrel, respectively. Revenues for the sale of natural gas were $3.0 million and $1.3 million, which resulted in realized prices of $3.15 and $2.43 per Mcf, respectively. Revenues for the sale of NGL were $4.5 million and $0.9 million, which resulted in realized prices of $28.07 and $12.97 per barrel of oil equivalent (“BOE”) of production, respectively. Average realized prices in the fourth quarter of 2017 were approximately $48.58 per barrel of oil, $2.98 per Mcf of natural gas and $37.82 per BOE of NGL, compared to fourth quarter of 2016 prices of approximately $42.61 per barrel of oil, $3.27 for Mcf of natural gas and $16.33 per BOE of NGL.

For the year ended December 31, 2017, in comparison to the year ended December 31, 2016, the Partnership benefited from increases in commodity prices for oil, natural gas and NGLs, as market prices increased from market lows experienced during the first quarter of 2016. Price gains were partially offset by the natural decline in production from existing wells, as the Partnership did not complete any wells during the year ended December 31, 2017 (six wells currently in different stages of the drilling and completion process are anticipated to be completed in the first quarter of 2018). Production for the interest acquired in Acquisition No. 1, which was owned for the entire periods presented, was approximately 1,200 BOE per day and approximately 1,517 BOE per day for the three months ended December 31, 2017 and 2016, respectively. Production for the interest acquired in Acquisition No. 1 was approximately 1,327 BOE per day and approximately 1,788 BOE per day for the years ended December 31, 2017 and 2016, respectively.

Production is dependent on the investment in existing wells and the development of new wells. Although the Partnership has elected to participate in the drilling of six new wells, the Partnership does not anticipate to realize any increases to overall production from these wells until the first quarter of 2018, and as a result, production is anticipated to decline until the new wells are operational. If the Partnership or its operator is unable or it is not cost beneficial to invest in existing wells or develop new wells, production will continue to decline.

Operating Costs and Expenses

Production Expenses

Production expenses are daily costs incurred by the Partnership to bring oil and natural gas out of the ground and to market, along with the daily costs incurred to maintain producing properties. Such costs include field personnel compensation, salt water disposal, utilities, maintenance, repairs and servicing expenses related to the Partnership's oil and natural gas properties, along with the gathering and processing contract in effect for the extraction, transportation and treatment of natural gas.

For the years ended December 31, 2017 and 2016, production expenses were $12.0 million and $5.8 million, respectively, and production expenses per BOE of production were $11.20 and $8.88, respectively. The increase per BOE for the year ended December 31, 2017 compared to the year ended December 31, 2016 is due primarily to the following factors: (a) in an effort to increase production, a portion of the Partnership's wells required substantial rework, resulting in an increase in workover expenses in 2017; (b) during the third quarter of 2016, the Partnership's operator amended its gathering and processing contract, which led to increases in certain gathering and processing costs subsequent to the amendment date; and (c) higher third-party fractionation expenses and plant processing costs in 2017.

In addition, while production expenses per BOE of production continued to stabilize throughout 2017, the Partnership experienced and continues to expect production expenses per BOE of production to increase due to natural production volume declines as reservoirs are depleted. Production expenses for the fourth quarters of 2017 and 2016 were $3.3 million and $1.5 million, respectively, and production expenses per BOE of production were $12.64 and $10.66, respectively.

Production Taxes

North Dakota's oil tax structure is comprised of two main taxes: the production tax and the extraction tax. The production tax is 5%. The extraction tax rate is also 5% of the gross value at the well. This rate can increase to 6% if the high-price trigger, defined as the average price of a barrel of oil exceeding a trigger price of $90 for each month in any consecutive three-month period, is in effect. The 6% rate would remain in effect until the average price is less than $90 per barrel for each month in any consecutive three-month period.

The production tax on gas is subject to a price index change on July 1 of each calendar year. The rate applicable from January 1, 2016 to June 30, 2016 was $0.1106 per Mcf, while the rate effective from July 1, 2016 through June 30, 2017 was $0.0601 per Mcf. The new rate, which became effective July 1, 2017 and will run through June 30, 2018, is $0.0555 per Mcf.

Production taxes for the years ended December 31, 2017 and 2016 were $3.4 million (8% of revenue) and $1.9 million (9% of revenue), respectively. Production taxes as a percentage of revenue have decreased as sales of natural gas and NGL have increased as a percentage of total sales. Taxes on the sale of gas and NGL products are less than taxes levied on the sale of oil based on current rates as a percentage of sale price. Production taxes for the fourth quarters of 2017 and 2016 were $0.9 million (8% of revenue) and $0.5 million (9% of revenue), respectively.

Depreciation, Depletion, Amortization and Accretion ("DD&A")

DD&A of capitalized drilling and development costs of producing oil, natural gas and NGL properties are computed using the unit-of-production method on a field basis based on total estimated proved developed oil, natural gas and NGL reserves. Costs of acquiring proved properties are depleted using the unit-of-production method on a field basis based on total estimated proved developed and undeveloped reserves. DD&A for the years ended December 31, 2017 and 2016 was $15.1 million and $9.5 million, and DD&A per BOE of production was $14.04 and $14.56, respectively. The decrease in DD&A expense per BOE of production is primarily the result of the increase of the Partnership's estimated reserves compared to the purchase price in conjunction with Acquisitions No. 2 and No. 3, combined with a change in estimated reserves.

General, Administrative and Other Expense

General and administrative costs for the years ended December 31, 2017 and 2016 were $0.9 million and $2.3 million, respectively. The principal components of general and administrative expense are accounting, legal and consulting fees as well as the Partnership's management fees due to E11 Management LLC (the "Former Manager", see discussion below) and acquisition costs. General and administrative expenses for the twelve months ended December 31, 2016 exceeded those for the comparable period of December 31, 2017 primarily due to the Partnership's estimated fees and reimbursable costs associated with the Former Manager. The Partnership incurred estimated fees and reimbursable costs of approximately $0.9 million for the year ended December 31, 2016. Actual costs were less than estimated and in 2017, the Partnership recorded a reduction of approximately $0.6 million of the Former Manager fees and reimbursable costs.

As discussed below, after the Partnership terminated its agreement with the Former Manager in April 2016, the Partnership has utilized additional external resources to replace certain services previously provided by the Former Manager. Therefore, the Partnership increased accounting and consulting fees, which are classified as general and administrative costs, beginning in the second quarter of 2016.

Derivative Instruments

In December 2017, the Partnership entered into derivative contracts with the objective to manage the commodity price risk on 2018 oil production and to reduce the effect of volatility in commodity price changes. As of December 31, 2017, the Partnership's derivative contracts (costless collars) were in a loss position based upon the contract's estimated fair market value at the balance sheet date. Based upon the estimated fair value of the derivative contracts as of December 31, 2017, the Partnership recorded a mark-to-market net loss of approximately $1.0 million. Changes in the fair value of the unsettled derivative contracts represent mark-to-market gains and losses and are recorded on the Partnership's consolidated statements of operations. The mark-to-market loss recorded by the Partnership does not represent an actual settlement and no payment was made to the counterparty in 2017.

The table below summarizes the Partnership's outstanding derivative contracts (costless collars – purchased put options and written call options) on the Partnership's 2018 oil production.

	Costless Collar Volumes (Bbl)	Weighted Average Floor / Ceiling Prices ($)
2018	330,000	52.33 / 57.52

Interest Expense

Interest expense, net, for the years ended December 31, 2017 and 2016 was $0.6 million and $6.1 million, respectively. The primary component of Interest Expense, net, during 2017 was interest expense on the notes payable executed in conjunction with Acquisitions No. 2 and No. 3 as well as the interest expense incurred on its revolving credit facility.

During 2016, Interest expense, net, included (a) nine months of interest expense on the $97.5 million seller note related to Acquisition No. 1 (the note was paid in full in September 2016), (b) nine months of amortization of the mark-to-market adjustment on the $97.5 million seller note; (c) origination costs for the $97.5 million seller note and (d) accretion of the Partnership's deferred purchase price and contingent consideration liabilities incurred with Acquisition No. 1.

Management Agreement

At the initial closing of the sale of common units on August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with a Former Manager to provide management and operating services regarding substantially all aspects of the Partnership. Under the Management Agreement, the Former Manager agreed to provide management and operating services to the Partnership in exchange for a monthly fee. In addition, the Partnership issued 100,000 Class B units to an affiliate of the Former Manager upon entering into the Management Agreement. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Distributions below.

Since substantially all the Partnership's properties are operated by Whiting and the Partnership only owns a non-operating working interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting. Consequently, the Partnership terminated the Management Agreement in 2016. The termination of the Management Agreement has not had an adverse effect on the Partnership's operations.

Supplemental Non-GAAP Measure

The Partnership uses "Adjusted EBITDAX", defined as earnings before (i) interest expense, net; (ii) income taxes; (iii) depreciation, depletion, amortization and accretion, (iv) exploration expenses; and (v) (gain)/loss on the mark-to-market of derivative instruments, as a key supplemental measure of its operating performance. This non-GAAP financial measure should be considered along with, but not as alternatives to, net income (loss), operating income, cash flow from operating activities or other measures of financial performance presented in accordance with GAAP. Adjusted EBITDAX is not necessarily indicative of funds available to fund the Company's cash needs, including its ability to make cash distributions. Although Adjusted EBITDAX, as calculated by the Partnership, may not be comparable to Adjusted EBITDAX as reported by other companies that do not define such terms exactly as the Partnership defines such terms, the Partnership believes this supplemental measure is useful to investors when comparing the Partnership's results between periods and with other energy companies.

The Partnership believes that the presentation of Adjusted EBITDAX is important to provide investors with additional information (i) to provide an important supplemental indicator of the operational performance of the Partnership's business without regard to financing methods and capital structure, and (ii) to measure the operational performance of the Partnership's operator.

The following table reconciles the Partnership's GAAP net loss to Adjusted EBITDAX for the years ended December 31, 2017 and 2016.

	Years ended December 31,	
	2017	**2016**
Net income (loss)	$ 7,896,322	$ (5,230,564)
Interest expense, net	654,476	6,132,805
Depreciation, depletion, amortization and accretion	15,084,504	9,526,865
Exploration expenses	-	-
Non-cash (gain) loss on mark-to-market of derivative instruments	1,026,965	-
Adjusted EBITDAX	$ 24,662,267	$ 10,429,106

Liquidity and Capital Resources

With the completion of the Partnership's best-efforts offering in April 2017, the Partnership's principal sources of liquidity are cash on hand, the cash flow generated from properties the Partnership has acquired and availability under the Partnership's revolving credit facility, discussed below. The Partnership anticipates that cash on hand, cash flow from operations and availability under the credit facility will be adequate to meet its anticipated liquidity requirements for at least the next 12 months, including the funding of the capital expenditures discussed above to complete the six in-progress wells.

Partners Equity

The Partnership completed its best-efforts offering of common units on April 24, 2017. As of the conclusion of the offering on April 24, 2017, the Partnership sold approximately 19.0 million common units for total gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

Under the agreement with the Dealer Manager, the Dealer Manager received a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, 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 in the offering, the total contingent fee is a maximum of approximately $15.0 million, which will only be paid if Payout occurs, as defined in "Distributions" below.

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 (owned by the General Partner), with respect to Class B units or the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout 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, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest (currently 43.125%).

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed above.

For the year ended December 31, 2017, the Partnership paid distributions of $1.361643 per common unit or $24.6 million, and for the year ended December 31, 2016, the Partnership paid distributions of $1.400000 per common unit or $10.4 million.

In 2017, the General Partner approved an adjustment to the annualized distribution rate to an annualized return of six percent based on a limited partner’s Net Investment Amount of $20.00 per common unit. The new distribution rate was effective with the November 29, 2017 distribution. The difference between any distribution and an annualized return of seven percent based on the Net Investment Amount is required to be paid before final Payout occurs as defined above. As of December 31, 2017, the unpaid Payout Accrual totaled $0.034521 per common unit, or approximately $0.7 million. While the Partnership’s goal is to maintain a relatively stable distribution rate over the life of its program, the General Partner monitors monthly Partnership distributions in conjunction with the Partnership’s projected cash requirements for operations, capital expenditures for new wells and debt service.

Financing

As part of the financing for Acquisition No. 2 on January 11, 2017, the Partnership executed a note in favor of the sellers in the original principal amount of $40.0 million. The Partnership paid the $40.0 million promissory note, which bore interest at 5%, in full on February 23, 2017. As part of the financing for Acquisition No. 3, the Partnership executed a promissory note in favor of the sellers in the original principal amount of $33.0 million. The Partnership paid the $33.0 million promissory note, which bore interest at 5%, in full on November 21, 2017, using proceeds from the revolving credit facility described below.

On November 21, 2017, the Partnership, as the borrower, entered into a loan agreement (the “Loan Agreement”) with Bank SNB (the “Lender”), which provides for a revolving credit facility (the “Credit Facility”) with an approved initial commitment amount of $20 million (the “Revolver Commitment Amount”), subject to borrowing base restrictions. The commitment amount may be increased up to $75 million with Lender approval. The Partnership paid an origination fee of 0.30% of the Revolver Commitment Amount, or $60,000, and is subject to additional origination fees of 0.30% for any borrowings made in excess of the Revolver Commitment Amount. The Partnership is also required to pay an unused facility fee of 0.50% on the unused portion of the Revolver Commitment Amount, based on the amount of borrowings outstanding during a quarter. The maturity date is November 21, 2019.

Under the Loan Agreement, the initial borrowing base is $30 million. However, the borrowing base is subject to redetermination semi-annually, in February and August, based upon the Lender’s analysis of the Partnership’s proven oil and natural gas reserves. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time. The interest rate, subject to certain exceptions, is equal to the London Inter-Bank Offered Rate (LIBOR) plus a margin ranging from 2.50% to 3.50%, depending upon the Partnership’s borrowing base utilization, as calculated under the terms of the Loan Agreement. At December 31, 2017, the interest rate for the Credit Facility was 4.76%.

At closing, the Partnership borrowed $20.0 million. The proceeds were used to repay closing costs, the $5.9 million outstanding balance of the note executed in conjunction with the Acquisition No. 3, and the $1.0 million deferred purchase price due to the seller in conjunction with Acquisition No. 1. The Credit Facility will provide additional liquidity for capital investments, including the drilling and completion of the six wells described below in “Oil and Gas Properties” and other corporate working capital requirements. Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. The Credit Facility is secured by a mortgage and first lien position on at least 80% of the Partnership’s producing wells.

The Credit Facility contains mandatory prepayment requirements, customary affirmative and negative covenants and events of default. The financial covenants include:

- a maximum leverage ratio
- a minimum current ratio
- maximum distributions

The Partnership was in compliance with the applicable covenants at December 31, 2017.

Oil and Gas Properties

The Partnership incurred approximately $3.2 million and $1.7 million in capital expenditures for the years ended December 31, 2017 and 2016, respectively. The Partnership expects to invest approximately $7.0 to $10.0 million in capital expenditures during 2018, which includes the completion of the six wells anticipated to be completed in the first half of 2018.

Since the Partnership is not the operator of any of its oil and natural gas properties, it is difficult to predict 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 difficult to forecast for 2018 and current estimated capital expenditures could be significantly different from amounts actually invested.

The Partnership expects to fund overhead costs and capital additions related to the drilling and completion of wells primarily from cash provided by operating activities and its revolving credit facility.

Contractual Commitments

The following is a summary of the Partnership’s significant contractual obligations as of December 31, 2017:

	Payments Due by Period (in thousands)				
	Total	1 year	2-3 years	4-5 years	Over 5 years
Revolving credit facility	$ 20,000	$ -	$ 20,000	$ -	$ -
Estimated interest payments (1)	1,799	953	846	-	-
Capital expenditures (2)	5,665	5,665	-	-	-
	$ 27,464	$ 6,618	$ 20,846	$ -	$ -

(1) Interest payments assume no principal repayments until the Credit Facility maturity date of November 21, 2019 and are estimated using the Partnership’s interest rate at December 31, 2017 of 4.76%.

(2) The Partnership executed authorization for expenditures (AFEs) in conjunction with the six in-progress wells at December 31, 2017. Based upon these AFEs, the Partnership estimates remaining capital expenditures for these wells to be approximately $5.7 million and will be paid in the first half of 2018.

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.

See further discussion in Note 9. Related Parties in Part II, Item 8 – Financial Statements and Supplementary Data and in Part III, Item 13 — Certain Relationships and Related Transactions, and Director Independence, appearing elsewhere in this Annual Report on Form 10-K.

Critical Accounting Policies

The discussion and analysis of the Partnership's financial condition and results of operations is based upon the consolidated financial statements, which have been prepared in accordance with U.S. generally accepted accounting principles. The preparation of these consolidated financial statements requires the Partnership to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosures about contingent assets and liabilities. Certain of the Partnership's accounting policies involve estimates and assumptions to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. The Partnership bases these estimates and assumptions on historical experience and on various other information and assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Estimates and assumptions about future events and their effects cannot be perceived with certainty and, accordingly, these estimates may change as additional information is obtained, as more experience is acquired, as the Partnership's operating environment changes and as new events occur.

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.

Oil and Natural Gas Properties

The Partnership accounts 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.

The successful efforts method of accounting can have a significant impact on the operational results reported when the Partnership is entering a new exploratory area in hopes of finding an oil and natural gas field that will be the focus of future developmental drilling activity. The initial exploratory wells may be unsuccessful and will be expensed. Seismic costs can be substantial, which will result in additional exploration expenses when incurred.

Impairment

The Partnership assesses 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. The underlying commodity prices used in the determination of the Partnership's 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 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.

Estimates of Oil, Natural Gas and Natural Gas Liquids Reserves

The Partnership's estimates of proved reserves are based on the quantities of oil, natural gas and natural gas liquids which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimate. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production, both of which provide accurate forecasts. Non–producing reserve estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods. These methods provide accurate forecasts due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. For example, the Partnership must estimate the amount and timing of future operating costs, severance taxes, development costs and workover costs, all of which may vary considerably from actual results. In addition, as prices and cost levels change from year to year, the estimate of proved reserves also changes. Any significant variance in these assumptions could materially affect the estimated quantity and value of the Partnership's reserves. Independent reserve engineers prepare the Partnership's reserve estimates at the end of each year.

Despite the inherent imprecision in these engineering estimates, the Partnership's reserves are used throughout the Partnership's financial statements. For example, since the Partnership uses the units–of–production method to amortize the costs of our oil and natural gas properties, the quantity of reserves could significantly impact its depreciation, depletion and amortization expense. The Partnership's reserves are also the basis of the Partnership's supplemental oil and natural gas disclosures.

Accounting for Asset Retirement Obligations

The Partnership has significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. The Partnership's 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 records 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 are 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 does 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 are 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 declared and paid $1.7 million, or $0.092055 per outstanding common unit, in distributions to its holders of common units.

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy Resources 12, L.P. that will give Energy Resources 12, L.P. access to the Partnership's personnel and administrative resources, including accounting, asset management and other day-to-day management support. 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 to the Partnership. The agreement may be terminated at any time by either party upon 60 days written notice. The chief executive officer and chief financial officer of the Partnership's General Partner are also chief executive officer and chief financial officer of the general partner of Energy Resources 12, L.P.

In February 2018, the Partnership declared and paid $1.7 million, or $0.092055 per outstanding common unit, in distributions to its holders of common units.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Information regarding the Partnership's hedging programs to mitigate commodity risks is contained in Item 1 – Business, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 8 – Financial Statements and Supplementary Data: Note 6. Risk Management, appearing elsewhere within this Annual Report on Form 10-K.

The Partnership also has a variable interest rate on its Credit Facility that is subject to market changes in interest rates. Information regarding the Partnership's Credit Facility is contained in Item 1 – Business, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations, and Item 8 – Financial Statements and Supplementary Data: Note 4. Debt, appearing elsewhere within this Annual Report on Form 10-K.

Item 8. Financial Statements and Supplementary Data

Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

General Partner and Unitholders
Energy 11, L.P.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Energy 11, L.P. (a Delaware limited partnership) and subsidiaries (the “Partnership”) as of December 31, 2017 and 2016, the related consolidated statements of operations, partners’ equity, and cash flows for each of the two years in the period ended December 31, 2017, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

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 supporting 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/ GRANT THORNTON LLP

We have served as the Partnership’s auditor since 2015.

Oklahoma City, Oklahoma
March 8, 2018

Energy 11, L.P.
Consolidated Balance Sheets

		December 31, 2017		December 31, 2016
Assets				
Cash and cash equivalents	$	11,090,846	$	86,800,596
Oil, natural gas and natural gas liquids revenue receivable		6,219,193		2,718,296
Other current assets		162,930		10,038,221
Total Current Assets		17,472,969		99,557,113
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization of $24,934,190 and $9,908,800, respectively		321,766,616		151,554,972
Total Assets	$	339,239,585	$	251,112,085
Liabilities				
Accounts payable and accrued expenses	$	2,733,131	$	2,622,400
Derivative liability		1,026,965		-
Total Current Liabilities		3,760,096		2,622,400
Revolving credit facility		20,000,000		-
Asset retirement obligations		1,226,879		70,623
Total Liabilities		24,986,975		2,693,023
Partners' Equity				
Limited partners' interest (18,973,474 and 14,582,963 common units issued and outstanding, respectively)		314,254,337		248,420,789
General partner's interest		(1,727)		(1,727)
Class B Units (62,500 units issued and outstanding, respectively)		-		-
Total Partners' Equity		314,252,610		248,419,062
Total Liabilities and Partners' Equity	$	339,239,585	$	251,112,085

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Operations

	Year Ended December 31, 2017	Year Ended December 31, 2016
Oil, natural gas and natural gas liquids revenues	$ 41,012,740	$ 20,365,338
Production expenses	12,034,976	5,811,111
Production taxes	3,406,171	1,870,212
General, administrative and other expense	909,326	2,254,909
Depreciation, depletion, amortization and accretion	15,084,504	9,526,865
Total operating costs and expenses	31,434,977	19,463,097
Operating income	9,577,763	902,241
Loss on derivatives	(1,026,965)	-
Interest expense, net	(654,476)	(6,132,805)
Total other expense, net	(1,681,441)	(6,132,805)
Net income (loss)	$ 7,896,322	$ (5,230,564)
Basic and diluted net income (loss) per common unit	$ 0.44	$ (0.69)
Weighted average common units outstanding - basic and diluted	18,112,836	7,538,180

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Partners' Equity

	Limited Partner Amount	Class B Units Amount	General Partner Amount	Total Partners' Equity
Balance December 31, 2015	$ 75,280,301	$ -	$ (1,727)	$ 75,278,574
Net proceeds from issuance of common units	188,820,033	-	-	188,820,033
Distributions declared and paid to common units ($1.400000 per unit)	(10,448,981)	-	-	(10,448,981)
2016 Net loss	(5,230,564)	-	-	(5,230,564)
Balance December 31, 2016	248,420,789	-	(1,727)	248,419,062
Net proceeds from issuance of common units	82,515,450	-	-	82,515,450
Distributions declared and paid to common units ($1.361643 per unit)	(24,578,224)	-	-	(24,578,224)
2017 Net income	7,896,322	-	-	7,896,322
Balance December 31, 2017	$ 314,254,337	$ -	$ (1,727)	$ 314,252,610

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Cash Flows

	For the Year Ended December 31, 2017	For the Year Ended December 31, 2016
Cash flow from operating activities:		
Net income (loss)	$ 7,896,322	$ (5,230,564)
Adjustments to reconcile net income (loss) to cash from operating activities:		
Depreciation, depletion, amortization and accretion	15,084,504	9,526,865
Loss on derivatives	1,026,965	-
Non-cash expenses, net	102,409	4,017,238
Changes in operating assets and liabilities:		
Oil, natural gas and natural gas liquids revenue receivable	(3,500,897)	(2,004,351)
Other current assets	(44,279)	(38,221)
Accounts payable and accrued expenses	100,972	678,417
Net cash flow provided by operating activities	20,665,996	6,949,384
Cash flow from investing activities:		
Cash paid for acquisition of oil and natural gas properties	(99,250,130)	(1,000,000)
Deposit for potential acquisition	-	(10,000,000)
Additions to oil and natural gas properties	(2,262,619)	(1,644,186)
Net cash flow used in investing activities	(101,512,749)	(12,644,186)
Cash flow from financing activities:		
Cash paid for loan costs	(87,742)	(250,000)
Net proceeds from revolving credit facility	20,000,000	-
Net proceeds from issuance of common units	82,510,325	188,825,158
Distributions paid to limited partners	(24,578,224)	(10,448,981)
Payments on notes payable	(72,707,356)	(88,917,833)
Net cash flow provided by financing activities	5,137,003	89,208,344
Increase (decrease) in cash and cash equivalents	(75,709,750)	83,513,542
Cash and cash equivalents, beginning of period	86,800,596	3,287,054
Cash and cash equivalents, end of period	$ 11,090,846	$ 86,800,596
Interest paid	$ 557,431	$ 2,171,573
Supplemental non-cash information:		
Note payable assumed in Acquisition No. 2	40,000,000	-
Note payable assumed in Acquisition No. 3	33,000,000	-
Increase in note payable, payment of contingent consideration	-	5,000,000
Decrease in note payable, settlement of pre-close activity	292,644	1,082,167

See notes to consolidated financial statements.

Energy 11, L.P.
Notes to Consolidated Financial Statements

Note 1. Partnership Organization

Energy 11, L.P. (the "Partnership") is a Delaware limited partnership formed to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership completed its best-efforts offering on April 24, 2017 with a total of approximately 19 million common units sold for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

As of December 31, 2017, the Partnership owned an approximate 26-27% non-operated working interest in 215 currently producing wells, six wells currently being drilled and approximately 247 future development sites in the Sanish field located in Mountrail County, North Dakota (collectively, the "Sanish Field Assets"), which is part of the Bakken shale formation in the Greater Williston Basin. Whiting Petroleum Corporation ("Whiting"), one of the largest producers in the basin, operates substantially all of the Sanish Field Assets.

The general partner of the Partnership is Energy 11 GP, LLC (the "General Partner"). The General Partner manages and controls the business affairs of the Partnership. David Lerner Associates, Inc. (the "Dealer Manager") was 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 consolidated financial statements of the Partnership have been prepared in accordance with United States generally accepted accounting principles ("US GAAP"). The consolidated financial statements include the accounts of the Partnership and its subsidiaries.

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.

Property and Depreciation, Depletion and Amortization

The Partnership accounts 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 assesses 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 our 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 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.

Accounts Receivable and Concentration of Credit Risk

Substantially all of the Partnership's accounts receivable are due from purchasers of oil, natural gas and NGLs or operators of the oil and natural gas properties. Oil, natural gas and NGL sales receivables are generally unsecured. This industry concentration has the potential to impact the Partnership's overall exposure to credit risk, in that the purchasers of the Partnership's oil, natural gas and NGLs and the operators of the properties the Partnership has an interest in may be similarly affected by changes in economic, industry or other conditions. At December 31, 2017, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2017, the Partnership's oil, natural gas and NGL sales were through two operators. Whiting Petroleum Corporation ("Whiting") is the operator of 99% of the Partnership's properties. All oil and natural gas producing activities of the Partnership are in North Dakota and represent substantially all of the business activities of the Partnership.

Asset Retirement Obligation

The Partnership has 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 records an asset retirement obligation ("ARO") and capitalizes 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.

The following table shows the activity for the years ended December 31, 2017 and 2016, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2015	$	105,459
Well additions		1,868
Accretion		9,689
Revisions in estimated cash flows		(46,393)
Balance as of December 31, 2016		70,623
Liabilities incurred on January 11, 2017 (acquisition)		781,628
Liabilities incurred on March 31, 2017 (acquisition)		289,827
Well additions		22,582
Accretion		59,114
Revisions in estimated cash flows		3,105
Balance as of December 31, 2017	$	1,226,879

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.

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

The Partnership follows the sales method of accounting for natural gas revenues. Under this method of accounting, revenues are recognized based on volumes sold, which may differ from the volume to which we are entitled based on our working interest. An imbalance is recognized as a liability only when the estimated remaining reserves will not be sufficient to enable the under–produced owner(s) to recoup its entitled share through future production. Under the sales method, no receivables are recorded where the Partnership has taken less than its share of production.

Environmental Costs

As the Partnership is directly involved in the extraction and use of natural resources, it is subject to various federal, state and local provisions regarding environmental and ecological matters. Compliance with these laws may necessitate significant capital outlays. The Partnership does not believe the existence of current environmental laws or interpretations thereof will materially hinder or adversely affect the Partnership's business operations; however, there can be no assurances of future effects on the Partnership of new laws or interpretations thereof. Since the Partnership does not operate any wells where it owns an interest, actual compliance with environmental laws is controlled by the well operators, with the Partnership being responsible for its proportionate share of the costs involved.

Environmental liabilities are recognized when it is probable that a loss has been incurred and the amount of that loss is reasonably estimable. Environmental liabilities, when accrued, are based upon estimates of expected future costs. At December 31, 2017 and 2016, there were no such costs accrued.

Use of Estimates

Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts and disclosures reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Of these estimates and assumptions, management considers the estimation of oil, natural gas and NGL reserves to be the most significant. These estimates affect the unaudited standardized measure disclosures, as well as depreciation, depletion and amortization ("DD&A") and impairment calculations. On an annual basis, the Partnership's independent consulting petroleum engineer, with assistance from the Partnership, prepares estimates of oil, natural gas and NGL reserves based on available geologic and seismic data, reservoir pressure data, core analysis reports, well logs, analogous reservoir performance history, production data and other available sources of engineering, geological and geophysical information. For DD&A purposes, and as required by the guidelines and definitions established by the SEC, the reserve estimates were based on average individual product prices during the 12-month period prior to December 31, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period excluding escalations based upon future conditions. For impairment purposes, projected NYMEX forward strip prices for oil, natural gas and NGL as estimated by management are used. Oil, natural gas and NGL prices are volatile and largely affected by worldwide production and consumption and are outside the control of management. Projected future oil, natural gas and NGL pricing assumptions are used by management to prepare estimates of oil, natural gas and NGL reserves used in formulating management's overall operating decisions.

The Partnership does 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 are 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.

Revenue Recognition

Oil, natural gas and natural gas liquids revenues are 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 our 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.

Reclassifications

Certain prior period amounts in the consolidated financial statements have been reclassified to conform to the current period presentation with no effect on previously reported net income (loss), partners' equity or cash flows.

Net Income (Loss) Per Common Unit

Basic net income (loss) per common unit is computed as net income (loss) divided by the weighted average number of common units outstanding during the period. Diluted net income (loss) per 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 years ended December 31, 2017 and 2016. As a result, basic and diluted outstanding common units were the same. The Class B Units and Incentive Distribution Rights are not included in net income (loss) per common unit until such time that it is probable Payout (as discussed in Note 7) 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. Early application is permitted for transactions that occur before the issuance or effective date of this amendment, provided the transaction has not been reported in financial statements that have been issued or made available for issuance. The Partnership adopted the standard effective January 1, 2017. The Partnership's acquisitions prior to 2017 were accounted for as acquisitions of an existing business and therefore, all transaction costs were expensed as incurred. The Partnership's acquisitions in the first quarter of 2017 were accounted for as asset purchases with acquisition costs, such as legal, title and accounting costs, being capitalized as part of the cost of the assets acquired. The Partnership will evaluate any future acquisition(s) of oil and gas properties under the revised standard and account for the acquisition as either an asset purchase or business combination depending on the particular facts and circumstances of the acquisition.

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 and 2017, the FASB issued several updates, including ASUs 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 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 using the modified retrospective approach. Based on its assessment of this standard, the Partnership does not believe the standard will have a significant change to the amount or timing of the recording of revenue in its consolidated financial statements.

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.

Note 3. Oil and Gas Investments

On December 18, 2015, the Partnership completed its purchase ("Acquisition No. 1") of an approximate 11% non-operated working interest in the Sanish Field Assets for approximately $159.6 million. The Partnership accounted for Acquisition No. 1 as a business combination, and therefore expensed, as incurred, transaction costs associated with this acquisition. These costs included, but were not limited to, due diligence, reserve reports, legal and engineering services and site visits.

On January 11, 2017, the Partnership completed its purchase ("Acquisition No. 2") of an additional approximate 11% non-operated working interest in the Sanish Field Assets for approximately $128.5 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 2 with the delivery of a promissory note in favor of the sellers of $40.0 million, which was paid in full in February 2017. The Partnership accounted for Acquisition No. 2 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the year ended December 31, 2017 were approximately $43,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.8 million in conjunction with this acquisition. Acquisition No. 2 increased the Partnership's non-operated working interest in the Sanish Field Assets to approximately 22-23%.

On March 31, 2017, the Partnership completed its purchase ("Acquisition No. 3") of an additional approximate average 10.5% non-operated working interest in 82 of the Partnership's then 216 existing producing wells and 150 of the Partnership's then 253 future development locations in the Sanish Field Assets for approximately $52.4 million. In addition to using cash on hand and proceeds from the best-efforts offering, the Partnership partially funded Acquisition No. 3 with a promissory note in favor of the sellers of $33.0 million, discussed further in Note 4. Notes Payable. The Partnership accounted for Acquisition No. 3 as a purchase of a group of similar assets, and therefore capitalized transaction costs associated with this acquisition. Total transaction costs incurred during the year ended December 31, 2017 were approximately $80,000. The Partnership also recorded an asset retirement obligation liability of approximately $0.3 million in conjunction with this acquisition. Acquisition No. 3 increased the Partnership's total non-operated working interest in the Sanish Field Assets to approximately 26-27%.

As of December 31, 2017, the Partnership owned an approximate 26-27% non-operated working interest in 215 currently producing wells, six wells currently being drilled and approximately 247 future development sites in the Sanish Field Assets.

The following unaudited pro forma financial information for the years ended December 31, 2017 and 2016 have been prepared as if Acquisitions No. 2 and No. 3 of the Sanish Field Assets had occurred on January 1, 2016. The unaudited pro forma financial information was derived from the historical Statements of Operations of the Partnership and the historical information provided by the sellers. The unaudited pro forma financial information does not purport to be indicative of the results of operations that would have occurred had the acquisitions of the Sanish Field Assets and related financings occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

	Year Ended December 31, 2017	Year Ended December 31, 2016
	(Unaudited)	(Unaudited)
Revenues	$ 43,355,472	$ 47,506,576
Net income	$ 7,957,922	$ 384,443

In October and November 2017, the Partnership elected to participate in the drilling and completion of six new wells. Four wells are being drilled and will be operated by Oasis Petroleum, Inc. (NYSE: OAS), and the Partnership will have an estimated approximate 7-9% non-operated working interest in these four wells. The other two wells are being drilled and will be operated by Whiting, and the Partnership will have an estimated approximate 29% non-operated working interest in these two wells. All six wells were started in late 2017 and are anticipated to be completed in the first half of 2018. In total, capital expenditures for the drilling and completion of the six wells discussed above are estimated to be approximately $7.0 million, of which approximately $1.3 million had been incurred as of December 31, 2017.

Note 4. Debt

As part of the financing for Acquisition No. 1 completed on December 18, 2015, the Partnership executed a note in favor of the sellers ("Seller Note 1") in the original principal amount of $97.5 million. On June 23, 2016, Seller Note 1 was increased by $5.0 million to satisfy the contingent payment due to the sellers as defined in the First Amendment of the Interest Purchase Agreement. The Partnership was given the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to satisfy the contingent payment in full by paying to the sellers $5.0 million at the time of election or by increasing the amount of Seller Note 1 by $5.0 million. On June 23, 2016, the Partnership exercised that right by increasing the amount of Seller Note 1 by $5.0 million. If the Partnership had not exercised the one-time right, the contingent payment would have ranged from $0 to $95 million depending on the average of the monthly NYMEX:CL strip prices as of December 31, 2017 for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022. Also in accordance with Seller Note 1, because the Partnership had not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership paid a deferred origination fee equal to $250,000 during the three months ended June 30, 2016. The deferred origination fee was amortized and expensed in full during the third quarter of 2016 and is included in "Interest expense, net" in the consolidated statements of operations. On September 29, 2016, the Partnership paid Seller Note 1 in full.

As part of the financing for Acquisition No. 2 completed on January 11, 2017, the Partnership executed a note ("Seller Note 2") in favor of the sellers in the original principal amount of $40.0 million. The Partnership paid the $40.0 million Seller Note 2, which bore interest at 5%, in full on February 23, 2017.

As part of the financing for Acquisition No. 3 completed on March 31, 2017, the Partnership executed a note ("Seller Note 3") in favor of the sellers in the original principal amount of $33.0 million. Seller Note 3 bore interest at 5% per annum and was payable in full no later than August 1, 2017 ("Maturity Date"). In July 2017, the Partnership and the sellers executed a First Amendment to Seller Note 3 ("Amended Note"), which extended the maturity date to June 29, 2018 ("Extended Maturity Date") provided the Partnership meets certain terms and conditions of the Amended Note, including making a $2.0 million payment on the outstanding principal balance by July 31, 2017. The $2.0 million payment was made by the Partnership on July 31, 2017. The Amended Note bore interest at 5% per annum. The Partnership paid the outstanding balance on the Amended Note of approximately $5.9 million, including interest, on November 21, 2017 in conjunction with the closing on the credit facility discussed below. There was no penalty for prepayment of the Amended Note.

On November 21, 2017, the Partnership, as the borrower, entered into a loan agreement (the “Loan Agreement”) with Bank SNB (the “Lender”), which provides for a revolving credit facility (the “Credit Facility”) with an approved initial commitment amount of $20 million (the “Revolver Commitment Amount”), subject to borrowing base restrictions. The commitment amount may be increased up to $75 million with Lender approval. The Partnership paid an origination fee of 0.30% of the Revolver Commitment Amount, or $60,000, and is subject to additional origination fees of 0.30% for any borrowings made in excess of the Revolver Commitment Amount. The Partnership is also required to pay an unused facility fee of 0.50% on the unused portion of the Revolver Commitment Amount, based on the amount of borrowings outstanding during a quarter. The maturity date is November 21, 2019.

Under the Loan Agreement, the initial borrowing base is $30 million. However, the borrowing base is subject to redetermination semi-annually, in February and August, based upon the Lender’s analysis of the Partnership’s proven oil and natural gas reserves. Outstanding borrowings under the Credit Facility cannot exceed the lesser of the borrowing base or the Revolver Commitment Amount at any time. The interest rate, subject to certain exceptions, is equal to the London Inter-Bank Offered Rate (LIBOR) plus a margin ranging from 2.50% to 3.50%, depending upon the Partnership’s borrowing base utilization, as calculated under the terms of the Loan Agreement. At December 31, 2017, the interest rate for the Credit Facility was 4.76%.

At closing, the Partnership borrowed $20.0 million. The proceeds were used to pay closing costs, the $5.9 million outstanding balance of the note executed in conjunction with the Acquisition No. 3, and the $1.0 million deferred purchase price due to the seller in conjunction with Acquisition No. 1. The Credit Facility will provide additional liquidity for capital investments, including the drilling and completion of the six wells described in “Note 3. Oil and Gas Investments,” and other corporate working capital requirements. Under the terms of the Loan Agreement, the Partnership may make voluntary prepayments, in whole or in part, at any time with no penalty. The Credit Facility is secured by a mortgage and first lien position on at least 80% of the Partnership’s producing wells.

The Credit Facility contains mandatory prepayment requirements, customary affirmative and negative covenants and events of default. The financial covenants include:

- a maximum leverage ratio
- a minimum current ratio
- maximum distributions

The Partnership was in compliance with the applicable covenants at December 31, 2017.

As of December 31, 2017 and 2016, the Partnership’s outstanding debt balance was $20.0 million and $0, respectively. The outstanding balance at December 31, 2017 of $20.0 million approximates its fair market value. The Partnership estimated the fair value of its note payable by discounting the future cash flows of the instrument at estimated market rates consistent with the maturity of a debt obligation with similar credit terms and credit characteristics, which are Level 3 inputs under the fair value hierarchy. Market rates take into consideration general market conditions and maturity.

Note 5. Fair Value of Financial Instruments

The Partnership follows authoritative guidance related to fair value measurement and disclosure, which establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement using market participant assumptions at the measurement date. Categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The three levels are defined as follows:

Level 1: Quoted prices in active markets for identical assets
Level 2: Significant other observable inputs – inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, either directly or indirectly, for substantially the full term of the financial instrument
Level 3: Significant unobservable inputs

The Partnership's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and the consideration of factors specific to the asset or liability. The Partnership's policy is to recognize transfers in or out of a fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Partnership has consistently applied the valuation techniques discussed above for all periods presented. During the years ended December 31, 2017 and 2016, there were no transfers in or out of Level 1, Level 2, or Level 3 assets and liabilities measured on a recurring basis.

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Partnership did not have any financial assets and liabilities that were accounted for at fair value as of December 31, 2016, except for those instruments discussed below in "Fair Value of Other Financial Instruments." The following table sets forth by level within the fair value hierarchy the Partnership's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2017.

	Fair Value Measurements at December 31, 2017		
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Commodity derivatives - current assets	$ -	$ -	$ -
Commodity derivatives - current liabilities	-	(1,026,965)	-
Total	$ -	$ (1,026,965)	$ -

The Level 2 instruments presented in the table above consist of Partnership's costless collar commodity derivative instruments. The fair value of the Partnership's derivative financial instruments is determined based upon future prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The fair value of the commodity derivatives noted above are included in the Partnership's consolidated balance sheet in Derivative liability at December 31, 2017. See additional detail in Note 6. Risk Management.

Fair Value of Other Financial Instruments

The carrying value of the Partnership's cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities reflect these items' cost, which approximates fair value based on the timing of the anticipated cash flows, current market conditions and short-term maturity of these instruments. In addition, see Note 4. Debt for the fair value discussion on the Partnership's debt.

Note 6. Risk Management

Participation in the oil and gas industry exposes the Partnership to risks associated with potentially volatile changes in energy commodity prices, and therefore, the Partnership's future earnings are subject to these risks. In December 2017, the Partnership began to utilize derivative contracts to manage the commodity price risk on the Partnership's future oil production it will produce and sell and to reduce the effect of volatility in commodity price changes to provide a base level of cash flow from operations. All derivative instruments are recorded on the Partnership's balance sheet as assets or liabilities measured at fair value. As of December 31, 2017, the Partnership's costless collar derivative instruments were in a net loss position; therefore, a current liability of approximately $1.0 million, which approximates its fair value, was recorded. The Partnership has not designated its derivative instruments as hedges for accounting purposes and has not entered into such instruments for speculative trading purposes. As a result, when derivatives do not qualify or are not designated as a hedge, the changes in the fair value are recognized on the Partnership's consolidated statements of operations as a gain or loss on derivative instruments. The Partnership has recognized a mark-to-market loss of approximately $1.0 million for the year ended December 31, 2017, recorded to the consolidated statements of operations as Loss on derivatives.

The Partnership determines the estimated fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets and quotes from third parties, among other things. The Partnership also performs an internal valuation to ensure the reasonableness of third-party quotes. In consideration of counterparty credit risk, the Partnership assessed the possibility of whether the counterparty to the derivative would default by failing to make any contractually-required payments. Additionally, the Partnership considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. See additional discussion above in Note 5. Fair Value of Financial Instruments.

The Partnership's derivative contracts are costless collars, which are used to establish floor and ceiling prices on future anticipated oil production. The Partnership did not pay or receive a premium related to the costless collar agreements. The contracts are settled monthly and there were no settlement payables or receivables at December 31, 2017. The follow table reflects open costless collar agreements as of December 31, 2017.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)	Fair Value of Asset / (Liability) at December 31, 2017
01/01/18 - 12/31/18	NYMEX	294,000	$ 52.00 / 57.05	$ (1,011,684)
01/01/18 - 12/31/18	NYMEX	36,000	$ 55.00 / 61.35	(15,281)
				$ (1,026,965)

All of the Partnership's outstanding derivative instruments are covered by an International Swap Dealers Association Master Agreement ("ISDA") entered into with the counterparty. The ISDA may provide that as a result of certain circumstances, such as cross-defaults, a counterparty may require all outstanding derivative instruments under an ISDA to be settled immediately. The Partnership has netting arrangements with the counterparty that provide for offsetting payables against receivables from separate derivative instruments.

Note 7. 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 was reimbursed for its documented third party out-of-pocket expenses incurred in organizing the Partnership and offering the common units.

The Partnership completed its best-efforts offering of common units on April 24, 2017. As of the conclusion of the offering on April 24, 2017, the Partnership had completed the sale of approximately 19.0 million common units for total gross proceeds of $374.2 million and proceeds net of offerings costs of $349.6 million.

Under the agreement with the Dealer Manager, the Dealer Manager received a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the common units sold. The Dealer Manager will also be paid a contingent incentive fee, 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 total contingent fee is approximately $15.0 million.

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 (owned by the General Partner), the Class B units or the contingent, incentive payments to the Dealer Manager, until Payout occurs.

The Partnership Agreement provides that Payout 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, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) to the Dealer Manager, as the Dealer Manager contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any (currently 13.125%), to the Record Holders of outstanding common units, pro rata based on their percentage interest until such time as the Dealer Manager receives the full amount of the Dealer Manager contingent incentive fee under the Dealer Manager Agreement;

Thereafter, (i) to the Record Holders of the Incentive Distribution Rights, 35%; (ii) to the Record Holders of the Outstanding Class B units, pro rata based on the number of Class B units owned, 35% multiplied by a fraction, the numerator of which is the number of Class B units outstanding and the denominator of which is 100,000 (currently, there are 62,500 Class B units outstanding; therefore, Class B units could receive 21.875%); (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest (currently 43.125%).

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed below.

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 $1.361643 per common unit, or $24.6 million. Effective with the November 29, 2017 distribution, the General Partner approved an adjustment to the annualized distribution rate to an annualized return of six percent based on a limited partner's Net Investment Amount of $20.00 per common unit. The difference between any distribution and an annualized return of seven percent based on the Net Investment Amount is required to be paid before final Payout occurs as defined above. As of December 31, 2017, the unpaid Payout Accrual totaled $0.034521 per common unit, or approximately $0.7 million. For the year ended December 31, 2016, the Partnership paid distributions of $1.400000 per common unit, or $10.4 million.

Note 8. Management Agreement

At the initial closing of the sale of common units on August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with E11 Management LLC (the "Former Manager") to provide management and operating services regarding substantially all aspects of the Partnership. Under the Management Agreement, the Former Manager agreed to provide management and operating services to the Partnership in exchange for a monthly fee. In addition, the Partnership issued 100,000 Class B units to an affiliate of the Former Manager upon entering into the Management Agreement. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Distributions above.

Since substantially all the Partnership's properties are operated by Whiting and the Partnership only owns a non-operating working interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting. Consequently, the Partnership terminated the Management Agreement in 2016. In conjunction with the termination, 37,500 of the Class B units were cancelled. For the year ended December 31, 2016, the Partnership incurred fees of approximately $0.9 million under the Management Agreement, which are included in General, administrative and other expense in the Partnership's consolidated statements of operations.

Note 9. 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.

On December 18, 2015, the General Partner appointed Clifford J. Merritt as its President. Prior to being appointed President, Mr. Merritt provided consulting services to the Partnership. For the years ended December 31, 2017 and 2016, Mr. Merritt was paid $336,588 and $338,396, respectively, by the Partnership. Effective February 1, 2018, the General Partner agreed to increase Mr. Merritt's base compensation to $400,000, plus benefits.

On July 1, 2016, the Partnership entered into a one-year lease agreement with an affiliate of the General Partner for office space in Oklahoma City, Oklahoma. Under the terms of the agreement, the Partnership made twelve monthly payments of $8,537. The terms of the agreement continued on a month-to-month basis at the same monthly rate for the remainder of 2017, and will continue on a month-to-month basis at the same monthly rate into 2018. For the years ended December 31, 2017 and 2016, the Partnership paid $102,444 and $51,222, respectively, to the affiliate of the General Partner.

For the years ended December 31, 2017 and 2016, approximately $320,000 and $285,000 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 $78,000 was due to a member of the General Partner.

The members of the General Partner are affiliates of Glade M. Knight, Chairman and Chief Executive Officer, David S. McKenney, Chief Financial Officer, Anthony F. Keating, III, Co-Chief Operating Officer and Michael J. Mallick, Co-Chief Operating Officer. Mr. Knight and Mr. McKenney are also the Chief Executive Officer and Chief Financial Officer of Energy Resources 12 GP, LLC, the general partner of Energy Resources 12, L.P. (“ER12”), 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 ER12 that will give ER12 access to the Partnership’s personnel and administrative resources, including accounting, asset management and other day-to-day management support. See Note 11. Subsequent Events for additional information on this agreement.

In November 2017, ER12 engaged Regional Energy Investors, LP (“REI”) to perform advisory and consulting services, including supporting ER12 through closing and post-closing on the purchase of certain oil and gas properties in North Dakota. REI is owned by entities that are controlled by Mr. Keating and Mr. Mallick and has engaged Mr. Merritt to support its operations.

E11 Incentive Holdings, LLC (“Incentive Holdings”) was the owner of all Class B units outstanding (62,500) as of March 31, 2017. During the second quarter of 2017, Incentive Holdings transferred substantially all of its assets; on April 5, 2017, Incentive Holdings transferred 18,125 of the 62,500 Class B units to E11 Incentive Carry Vehicle, LLC, an affiliate of Incentive Holdings, for de minimis consideration. On April 6, 2017, the remaining 44,375 Class B units were acquired by Regional Energy Incentives, LP in exchange for approximately $98,000. Regional Energy Incentives, LP is owned by entities that are controlled by Mr. Keating, Mr. Mallick and Mr. McKenney. The Class B units entitle the holder to certain distribution rights after Payout, as described in Note 7. Capital Contribution and Partners’ Equity.

Note 10. Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)

Aggregate Capitalized Costs

The aggregate amount of capitalized costs of oil, natural gas and NGL properties and related accumulated depreciation, depletion and amortization as of December 31, 2017 and 2016 is as follows:

	2017	2016
Producing properties	$ 186,647,918	$ 94,199,024
Non-producing	160,052,888	67,264,748
	346,700,806	161,463,772
Accumulated depreciation, depletion and amortization	(24,934,190)	(9,908,800)
Net capitalized costs	$ 321,766,616	$ 151,554,972

Costs Incurred

For the years ended December 31, 2017 and 2016, the Partnership incurred the following costs in oil and natural gas producing activities:

	2017	2016
Property acquisition costs	$ 180,957,486	$ 524,175
Development costs	4,279,548	1,652,782
	$ 185,237,034	$ 2,176,957

Estimated Quantities of Proved Oil, NGL and Natural Gas Reserves

The following unaudited information regarding the Partnership's oil, natural gas and NGL reserves is presented pursuant to the disclosure requirements promulgated by the SEC and the FASB.

Proved oil and natural gas reserves are those quantities of oil, natural gas and NGLs which, by analysis of geosciences and engineering data, can be estimated with reasonable certainty to be economically producible – from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons as seen in a well penetration unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

The independent consulting petroleum engineering firm of Pinnacle Energy of Oklahoma City, OK, prepared estimates of the Partnership's oil, natural gas and NGL reserves as of December 31, 2017, 2016 and 2015.

The Partnership's net proved oil, NGL and natural gas reserves, all of which are located in the contiguous United States, as of December 31, 2017, 2016 and 2015, have been estimated by the Partnership's independent consulting petroleum engineering firm. Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007)." The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data and production history.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production-decline curves, reserves were estimated only to the limits of economic production or to the limit of the production licenses as appropriate. Accordingly, these estimates should be expected to change, and such changes could be material and occur in the near term as future information becomes available. "Revisions of previous estimates" in the table below represent changes in previous reserve estimates, either upward or downward, resulting from a change in economic factors, such as commodity prices, operating costs or development costs, or resulting from information obtained from the Partnership's production history.

Net quantities of proved, developed and undeveloped oil, natural gas and NGL reserves are summarized as follows:

	Proved Reserves			
	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
December 31, 2015	9,067,315	7,687,410	1,863,934	12,212,484
Acquisition	-	-	-	-
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (1)	222,321	2,799,032	(576,645)	112,182
Production	(498,926)	(519,122)	(69,059)	(654,506)
December 31, 2016	8,790,710	9,967,320	1,218,230	11,670,160
Acquisition (2)	13,192,588	14,885,856	1,819,384	17,492,948
Extensions, discoveries and other additions	-	-	-	-
Revisions of previous estimates (3)	(3,434,686)	(3,691,027)	659,326	(3,390,531)
Production	(756,470)	(936,818)	(161,845)	(1,074,451)
December 31, 2017	17,792,142	20,225,331	3,535,095	24,698,126

(1) Revisions to previous estimates increased proved reserves by a net amount of 112 MBOE. These revisions resulted from 800 MBOE of upward adjustments attributable to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule, 124 MBOE of downward adjustments related to well performance and 217 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2016 to December 31, 2015.

Revisions of previous estimates for total proved reserves from December 31, 2015 to December 31, 2016 of 112 MBOE (increase) were less than revisions of previous estimates for proved undeveloped reserves for the same period of 442 MBOE (increase), primarily due to the incremental downward adjustment revisions to the proved developed reserves caused by changes in lower oil, natural gas and NGL prices (206 MBOE) and well performance (124 MBOE).

(2) The Partnership acquired 11,670 MBOE and 5,823 MBOE of producing developed wells and PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 17,493 MBOE during the year ended December 31, 2017.

(3) Revisions to previous estimates decreased proved reserves by a net amount of 3,391 MBOE. These revisions result from 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule and 1,213 MBOE of downward adjustments related to well performance, which were partially offset by 690 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the Partnership's reserve estimates at December 31, 2017 to December 31, 2016.

In accordance with SEC Regulation S-X, Rule 4-10, as amended, the Partnership uses the 12-month average price calculated as the unweighted arithmetic average of the spot price on the first day of each month within the 12-month period prior to the end of the reporting period. The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2017 were $51.34 per barrel of oil and $2.98 per MMcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2017 were $44.84 per barrel of oil, $0.12 per MMcf of natural gas and $16.94 per barrel of NGL. The oil and natural gas prices used in computing the Partnership's reserves as of December 31, 2016 were $42.75 per barrel of oil and $2.48 per Mcf of natural gas, before price differentials. Including the effect of price differential adjustments, the average realized prices used in computing the Partnership's reserves as of December 31, 2016 were $36.25 per barrel of oil, ($0.38) per Mcf of natural gas and $4.70 per barrel of NGL. The gathering and processing contract in effect for the extraction, transportation and treatment of natural gas led to a price differential that exceeded the twelve-month average market price for natural gas, which results in an estimated negative average realized natural gas price utilized in the December 31, 2016 reserves calculation.

	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
Proved developed reserves:				
December 31, 2016	4,748,350	5,163,240	631,080	6,239,970
December 31, 2017	9,640,723	11,300,071	1,975,089	13,499,157
Proved undeveloped reserves:				
December 31, 2016	4,042,360	4,804,080	587,150	5,430,190
December 31, 2017	8,151,419	8,925,260	1,560,006	11,198,968

The following details the changes in proved undeveloped reserves for 2016 and 2017:

	BOE
Proved undeveloped reserves, December 31, 2015	4,988,274
Revisions of previous estimates (1)	441,916
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430,190
Revisions of previous estimates (2)	(2,838,164)
Conversion to proved developed reserves (3)	(518,686)
Proved undeveloped reserves acquired (4)	9,125,628
Proved undeveloped reserves, December 31, 2017	11,198,968

(1) The annual review of the PUDs resulted in a positive revision of approximately 442 MBOE. This revision was a result of 800 MBOE of upward adjustments related to the addition of nine proved undeveloped drilling locations under the five-year rule, which were partially offset by 347 MBOE of downward adjustments related to changes to the future drill schedule and 11 MBOE of downward adjustments caused by lower oil, natural gas and NGL prices when comparing the December 31, 2016 reserve estimates to prices used in the December 31, 2015 reserve estimates. There were no adjustments related to well performance.

(2) The annual review of the PUDs resulted in a negative revision of approximately 2,838 MBOE. This revision was the result of 2,868 MBOE of downward adjustments attributable to changes in the future drill schedule, which were partially offset by 30 MBOE of upward adjustments caused by higher oil, natural gas and NGL prices when comparing the December 31, 2017 reserve estimates to prices used in the December 31, 2016 reserve estimates. There were no adjustments related to well performance.

(3) The Partnership is participating in the drilling and completion of six wells, which are in progress at December 31, 2017 (see Note 3. Oil and Gas Investments) and represent a conversion of 519 MBOE from the PUD category to proved developed for the year ended December 31, 2017.

(4) The Partnership acquired 5,430 MBOE and 3,696 MBOE of PUDs in conjunction with Acquisitions No. 2 and No. 3, respectively (see Note 3. Oil and Gas Investments), for a total of 9,126 MBOE during the year ended December 31, 2017.

Although the Partnership has performed limited drilling since acquisition, the Partnership anticipates all current PUD locations will be drilled and converted to PDP within five years of the date they were added. PUD locations and associated reserves which are no longer projected to be drilled within five years from the date they were first booked as proved undeveloped reserves will be removed as revisions at the time that determination is made.

Standardized Measure of Discounted Future Net Cash Flows

Accounting standards prescribe guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. The Partnership has followed these guidelines, which are briefly discussed below.

Future cash inflows and future production and development costs are determined by applying the trailing unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs to the estimated quantities of oil, natural gas and NGL to be produced. Actual future prices and costs may be materially higher or lower than the unweighted 12-month arithmetic average of the first-day-of-the-month individual product prices and year-end costs used. For each year, estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on continuation of the economic conditions applied for such year.

The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor. The assumptions used to compute the standardized measure are those prescribed by the FASB and, as such, do not necessarily reflect the Partnership's expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computations since these estimates affect the valuation process.

	2017	2016
Future cash inflows	$ 860,125,991	$ 320,606,188
Future production costs	(292,788,015)	(122,527,901)
Future development costs	(96,111,664)	(43,050,408)
Future net cash flows	471,226,312	155,027,879
10% annual discount	(285,321,062)	(94,081,952)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

Changes in the standardized measure of discounted future net cash flows are as follows:

	2017	2016
Standardized measure at beginning of period	$ 60,945,927	$ 99,189,842
Changes resulting from:		
Acquisition of reserves	97,630,985	524,175
Sales of oil, natural gas and NGLs, net of production costs	(25,571,593)	(12,684,015)
Net changes in prices and production costs	85,222,533	(28,508,492)
Development costs incurred during the period	4,279,548	1,652,782
Revisions to previous estimates	(57,488,282)	(3,750,720)
Accretion of discount	6,103,044	9,932,739
Change in estimated future development costs	14,783,088	(5,410,384)
Standardized measure of discounted future net cash flows	$ 185,905,250	$ 60,945,927

Note 11. Quarterly Financial Data (Unaudited)

The following is a summary of quarterly results of operations for the years ended December 31, 2017 and 2016. Net income (loss) per common unit is non-additive in comparison to net income (loss) per common unit for each year due to the timing and size of the Partnership's common unit issuances.

	2017			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 10,141,266	$ 10,208,740	$ 9,717,996	$ 10,944,738
Net income	$ 2,621,071	$ 1,986,404	$ 1,280,559	$ 2,008,288
Basic and diluted net income per common share	$ 0.17	$ 0.11	$ 0.07	$ 0.11

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ 4,319,097	$ 5,532,113	$ 5,434,047	$ 5,080,081
Net income (loss)	$ (3,592,456)	$ (859,383)	$ (1,511,146)	$ 732,421
Basic and diluted net income (loss) per common share	$ (0.73)	$ (0.14)	$ (0.20)	$ 0.06

Note 12. Subsequent Events

In January 2018, the Partnership declared and paid $1.7 million, or $0.092055 per outstanding common unit, in distributions to its holders of common units.

On January 31, 2018, the Partnership entered into a cost sharing agreement with Energy Resources 12, L.P. that will give Energy Resources 12, L.P. access to the Partnership's personnel and administrative resources, including accounting, asset management and other day-to-day management support. 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 to the Partnership. The agreement may be terminated at any time by either party upon 60 days written notice. The chief executive officer and chief financial officer of the Partnership's General Partner are also chief executive officer and chief financial officer of the general partner of Energy Resources 12, L.P.

In February 2018, the Partnership declared and paid $1.7 million, or $0.092055 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 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

Partnership 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 management, including the Chief Executive Officer and Chief Financial Officer of the General Partner, of the effectiveness of our internal control over financial reporting. Partnership management assessed the effectiveness of its internal control over financial reporting as of December 31, 2017. Partnership 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, Partnership 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 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	*Chairman of the Board and Chief Executive Officer*
David S. McKenney	55	*Director and Chief Financial Officer and Secretary*
Anthony Francis “Chip” Keating III	38	*Director and Co-Chief Operating Officer*
Michael J. Mallick	55	*Director and Co-Chief Operating Officer*
Clifford J. Merritt	57	*President*

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

Glade M. Knight. Mr. Knight has been the Chairman of the Board and Chief Executive Officer of the General Partner since its formation in July 2013. Mr. Knight is also part owner of and the Chief Executive Officer of Energy Resources 12 GP, LLC, the general partner of Energy Resources 12, L.P., a partnership focused on investments in the oil and gas industry. Mr. Knight also is the founder and 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 the merger in 2005 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 REIT Seven, Inc. (“Apple Seven”), Apple REIT Eight, Inc. (“Apple Eight”), Apple REIT Nine, Inc. (“Apple Nine”) and their related advisory companies entered into settlement agreements with the SEC. Along with Apple REIT Seven, Apple REIT Eight, Apple REIT 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 a Director and Chief Financial Officer and Secretary of the General Partner since its formation in July 2013. Mr. McKenney is also part owner of and the Chief Financial Officer of Energy Resources 12 GP, LLC, the general partner of Energy Resources 12, L.P., a partnership 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.

Anthony Francis "Chip" Keating III. Mr. Keating has been a Director and Co-Chief Operating Officer of the General Partner since its formation in July 2013. Mr. Keating has been a principal with Rock Creek Capital, a real estate and oil and gas investment company, since March 2010. Mr. Keating also is an officer of the General Partner of Regional Energy Investors, LP, a partnership that provides consulting services in the oil and gas industry. He served on the board of Apple REIT Ten, Inc. until the merger with Apple Hospitality REIT, Inc. in September 2016. He is currently the President of the board of The Children's Hospital Foundation in Oklahoma City and a Director of the Oklahoma State Troopers Foundation, Inc. Mr. Keating is also a Director and Gubernatorial appointee of The Oklahoma Law Enforcement Retirement System by Governor Mary Fallin. Prior to founding Rock Creek Capital, Mr. Keating served as the Real Estate Development Manager for Chesapeake Energy Corporation in Oklahoma City, Oklahoma from March 2007 to March 2010. While at Chesapeake, Mr. Keating closed and transacted over $850 million in real estate transactions ranging from corporate headquarters, sale leasebacks, field offices, investment properties and raw land in urban natural gas plays for drill sites. Prior to joining Chesapeake, Mr. Keating worked as a commercial real estate broker with Trammell Crow Company from August 2004 to March 2007. While at Trammell Crow Company, he specialized in tenant representation and investment sales. Before joining Trammell Crow Company, he spent over three years as an Oklahoma State Trooper from May 2001 to August 2004. Mr. Keating received a Bachelor of Business Administration from Southern Methodist University.

Michael J. Mallick. Mr. Mallick has been a Director and Co-Chief Operating Officer of the General Partner since its formation in July 2013. Mr. Mallick also is an officer of the General Partner of Regional Energy Investors, LP, a partnership that provides consulting services in the oil and gas industry. Mr. Mallick is the founder of Fort Worth, Texas-based Mallick Group, Inc., a real estate and energy-related investment firm. Mr. Mallick is a principal investor in various entities and serves as the principal officer of sponsoring and managing partners for numerous and diverse real estate investments and energy-related interests funded with established co-investment relationships with high net worth private investors, institutional investors and lenders. Mr. Mallick's varied experience includes development of the 349 room Horseshoe Bay Marriot Resort Hotel, located in Horseshoe Bay, Texas (financed with a national pension fund); Sierra Vista, a redevelopment initiative in a public/private partnership with the City of Fort Worth, Texas, including the assemblage and acquisition of approximately 300 acres located within a concentration of blight inside the central city and resulting in environmental remediation and demolition of 1,000 crime-ridden apartment units and new quality affordable housing and shopping; and acquisition of a large multi-property portfolio of properties financed via a structured private placement offering with multiple institutional investors. Mr. Mallick serves on the Board of Directors of S2K Financial, LLC, a New York based financial services firm, and also serves on the Board of Directors of the Oklahoma State Troopers Foundation, Inc.

Clifford J. Merritt. On December 18, 2015, Mr. Merritt was appointed as President of the General Partner. Mr. Merritt had been a consultant to us since July 1, 2014, and to other private exploration and development companies since November 2013. Prior to that time and since 2004 he was employed by Chesapeake Energy Corporation. From 2010 to 2013 he served as Chesapeake's Vice President Land – Southern Division and from 2005 to 2010 as Chesapeake's Land Manager – Barnett Shale District. Before joining Chesapeake he worked for Okland Oil, Ricks Exploration and Concho Resources during the years of 1990 through 2003, each of which is an independent oil and gas company. He has a B.B.A. from the University of Central Oklahoma and is a member of OCAPL (Oklahoma City Association of Professional Landmen) and AAPL (American Association of Professional Landmen). During his career, Mr. Merritt has been involved and managed the Land functions of numerous acquisitions and divestitures of oil and gas properties and supervised the drilling and completion of over 2,000 oil and gas wells throughout multiple states in the continental US. Additionally, Mr. Merritt provides consulting services to Regional Energy Investors, LP.

The General Partner

The General Partner is Energy 11 GP, LLC, which was formed in 2013 and has no operating history. The General Partner was formed and is owned by companies controlled by Glade M. Knight, David S. McKenney, Anthony "Chip" F. Keating III, and Michael J. Mallick.

The General Partner will not receive a management or similar fee for acting as General Partner and will not receive an offering and organization fee for organizing the Partnership. The Partnership 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 Partnership other than reimbursement of third-party costs and expenses and with respect to their equity interests in the Partnership.

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.energyeleven.com.

Audit and Compensation Committee

The Partnership does not have a formal compensation committee and the General Partner's Board of Directors serves as the audit committee. Because the Partnership does not have and are 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 members of the Board of Directors or committees thereof 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 its directors is an audit committee financial expert.

Item 11. Executive Compensation

Summary Compensation

The following table summarizes, with respect to each of the Chief Executive Officer and the two other most highly compensated officers of the General Partner (the "Named Executive Officers"), information relating to the compensation earned for services rendered in all capacities during the fiscal years ended December 31, 2017 and 2016. Since the only person being paid any compensation by the Partnership or the General Partner is Mr. Merritt, the Named Executive Officers only include Mr. Knight, the Chief Executive Officer, and Mr. Merritt.

Name and Principal Position:	Year	Salary	Bonus	All Other Compensation	Total
Glade M. Knight	2017	$ —	$ —	$ —	$ —
Chairman of the Board and Chief Executive Officer	2016	$ —	$ —	$ —	$ —
Clifford J. Merritt (1)	2017	$ 306,588	$ 30,000	$ —	$ 336,588
President	2016	$ 308,396	$ 30,000	$ —	$ 338,396

(1) Mr. Merritt was appointed the President of the General Partner in December 2015.

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 owners of the General Partner will be reimbursed for documented out-of-pocket travel, entertainment and similar expenses incurred by them in connection with attending board of directors meetings or managing the Partnership's business. The owners of the General Partner will not receive any salary, bonus or consulting fees for serving on the board of directors or managing the Partnership's business other than distributions in accordance with the incentive distribution rights, if any.

For the years ended December 31, 2017 and 2016, the General Partner agreed to pay Mr. Merritt base compensation of $300,000, basic health insurance benefits, which will be paid or reimbursed to the General Partner by the Partnership and a 5% interest in the General Partner's incentive distribution rights. Effective February 1, 2018, the General Partner agreed to increase Mr. Merritt's base compensation to $400,000.

Outstanding Equity Awards at Fiscal Year-End

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

Compensation of Directors

The employee and non-employee members of the General Partner's board of directors do not receive compensation for their services as directors. However, the directors may be reimbursed for their expenses in attending board meetings.

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

The following table sets forth as of March 1, 2018 the beneficial ownership of the Partnership's common units and Class B units that are owned by:

- all persons who, to the knowledge of the Partnership's 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	Class B Units Beneficially Owned	Percentage of Class B 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	*	4,437	7%
Anthony Francis "Chip" Keating III 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*	19,969	32%
Michael J. Mallick 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	5,000	*	19,969	32%
Cliff Merritt 120 W. 3rd Street, Suite 220 Fort Worth, Texas 76102	-	-	-	-
Directors and principal officers as a group (5 persons)	20,000	*	44,375	71%

* Less than 1% of outstanding common units.

Class B Units

Regional Energy Incentives, LP, owned by entities that are controlled by Mr. Keating, Mr. Mallick and Mr. McKenney, owns 44,375 Class B units. The address of Regional Energy Incentives, LP is 3715 Camp Bowie Blvd, Fort Worth, Texas 76107. The remaining 18,125 Class B units are owned by E11 Incentive Carry Vehicle, LLC, an affiliate of Incentive Holdings, LLC. The address of E11 Incentive Carry Vehicle, LLC is 301 NW 63rd Street, Suite 400, Oklahoma City, Oklahoma 73116.

The Partnership may issue up to 37,500 additional Class B units, the amount of Class B units canceled in conjunction with the termination of the Management Agreement discussed in Note 8. Management Agreement of Part II, Item 8 – Financial Statements and Supplementary Data of this Annual Report on Form 10-K.

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 25% membership interest in the General Partner. GKOG, LLC is a limited liability company wholly owned by Mr. Knight.
- DMOG, LLC owns a 25% membership interest in the General Partner. DMOG, LLC is a limited liability company wholly owned by Mr. McKenney.
- CFK Energy, LLC owns a 25% membership interest in the General Partner. CFK Energy, LLC is a limited liability company owned by Mr. Keating and his immediate family.
- Pope Energy Investors, LP, a limited partnership, owns a 25% membership interest in the General Partner. The General Partner and the limited partner interests of Pope Energy Investors, LP are owned by Mr. Mallick and his immediate family.

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 three 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 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 years ended December 31, 2017 and 2016, approximately $320,000 and $285,000, respectively, 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.

Incentive Distribution Rights

On the initial closing date, the Partnership issued incentive distribution rights, which are nonvoting limited partner interests that entitle the holder of such rights to 35% of all amounts distributed by the Partnership after Payout occurs, to the General Partner.

Regional Energy Investors, LP

In November 2017, Energy Resources 12, L.P. ("ER12"), a limited partnership that also invests in producing and non-producing oil and gas properties on-shore in the United States, engaged Regional Energy Investors, LP ("REI") to perform advisory and consulting services, including supporting ER12 through closing and post-closing on the purchase of certain oil and gas properties in North Dakota. REI is owned by entities that are controlled by Anthony F. Keating, III and Michael J. Mallick, Co-Chief Operating Officers of the Partnership. Glade M. Knight and David S. McKenney are the Chief Executive Officer and Chief Financial Officer, respectively, of the General Partner as well as the Chief Executive Officer and Chief Financial Officer, respectively, of Energy Resources 12 GP, LLC, the general partner of ER12.

Cost Sharing Agreement

On January 31, 2018, the Partnership entered into a cost sharing agreement with ER12 that will give ER12 access to the Partnership's personnel and administrative resources. The personnel will provide accounting, asset management and other day-to-day management support for both partnerships. 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 to the Partnership. The agreement may be terminated at any time by either party upon 60 days written notice.

Consulting Fees to Clifford Merritt

On December 18, 2015 the General Partner, appointed Clifford J. Merritt as its President. Prior to being appointed President Mr. Merritt provided consulting services to the General Partner. For the years ended December 31, 2017 and 2016, Mr. Merritt was paid $336,588 and $338,396, respectively. Effective February 1, 2018, the General Partner agreed to increase Mr. Merritt's base compensation to $400,000.

Office Lease

On July 1, 2016, the Partnership entered into a one-year lease agreement with an affiliate of the General Partner for office space in Oklahoma City, Oklahoma. Under the terms of the agreement, the Partnership made twelve monthly payments of $8,537. The terms of the agreement continued on a month-to-month basis at the same monthly rate for the remainder of 2017, and will continue on a month-to-month basis at the same monthly rate into 2018. For the years ended December 31, 2017 and 2016, the Partnership paid $102,444 and $51,222, respectively, to the affiliate of 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 has not made any determination as to whether the 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

Grant Thornton LLP ("Grant Thornton") has audited the Partnership's consolidated financial statements for the most recent fiscal year ended December 31, 2017. Grant Thornton was selected and appointed as the Partnership's independent registered public accounting firm on March 18, 2015.

For the fiscal years ended December 31, 2017 and 2016, fees paid or payable to Grant Thornton for services performed in connection with the audit of the 2017 financial statements, the audit of the 2016 financial statements, reviews of the amended S-1s, SEC comment letters, issuance of consents and 2017 and 2016 interim reviews are as follows:

Audit Fees

	Year Ended December 31, 2017	Year Ended December 31, 2016
Audit fees	$ 189,500	$ 149,150
Audit-related fees	—	—
Tax fees	—	—
All other fees	—	—
Total	$ 189,500	$ 149,150

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. The Board of Directors reviews the actual and budgeted fees for the independent public accountants periodically at regularly scheduled board meetings. All of the services provided by Grant Thornton during the years ended December 31, 2017 and 2016 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 – Grant Thornton LLP

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

   (iii) Consolidated Statements of Operations for the years ended December 31, 2017 and 2016

   (iv) Consolidated Statements of Partners' Equity for the years ended December 31, 2017 and 2016

   (v) Consolidated Statements of Cash Flows for the years ended December 31, 2017 and 2016

   (vi) Notes to 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 NUMBER	Description Of Exhibit
1.1	Exclusive Dealer Manager Agreement with David Lerner Associates, Inc. (incorporated by reference from Exhibit 1.1 to Amendment No. 7 to the Partnership's Registration Statement on Form S-1 filed on December 31, 2014).
2.1	Exclusive Option Agreement dated November 3, 2016 among Energy 11 Operating Company, LLC, Kaiser-Whiting, LLC, and Don P. Millican (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed on November 4, 2016).
2.2	Interest Purchase Agreement dated January 4, 2017 among Energy 11 Operating Company, LLC, Kaiser-Whiting, LLC, and the owners of Kaiser-Whiting, LLC (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed on January 12, 2017).
2.3	First Amendment to Interest Purchase Agreement by and among Energy 11 Operating Company, LLC, a Delaware limited liability company, Kaiser-Whiting, LLC, an Oklahoma limited liability company and the owners of all the limited liability company interests in Kaiser-Whiting, LLC (incorporated by reference from Exhibit 2.5 to the Partnership's Annual Report on Form 10-K filed on March 3, 2017).
2.4	Interest Purchase Agreement dated March 8, 2017 among Energy 11 Operating Company, LLC, Kaiser Acquisition and Development – Whiting, LLC, and Kaiser Acquisition and Development, LLC and George B. Kaiser (incorporated by reference from Exhibit 2.1 to the Partnership's Current Report on Form 8-K filed on March 10, 2017)
3.1	Certificate of limited partnership of Energy 11, L.P. (incorporated by reference from Exhibit 3.1 to Amendment No. 4 to the Partnership's Registration Statement on Form S-1 filed on November 21, 2014).
3.2	First Amended and Restated Limited Partnership Agreement of Energy 11, L.P. dated as of August 19, 2015 (incorporated by reference from Exhibit A to the Prospectus included as part of the Amendment No. 6 to the Partnership's Registration Statement on Form S-1 filed on December 12, 2014).
10.1	Form of Subscription Agreement (incorporated by reference from Exhibit B to the Prospectus included as part of Amendment No. 6 to the Partnership's Registration Statement on Form S-1 filed with the SEC on December 12, 2014).
10.2	Letter Agreement between Energy 11 GP, LLC and Clifford Merritt (incorporated by reference from Exhibit 10.2 to the Partnership's Current Report on Form 8-K filed on December 21, 2015).
10.3	Secured Promissory Note dated January 11, 2017 executed by Energy 11 Operating Company, LLC in favor of Kaiser-Francis Management Company, L.L.C. (incorporated by reference from Exhibit 10.1 to the Partnership's Current Report on Form 8-K filed on January 12, 2017).
10.4	Secured Promissory Note dated March 31, 2017 executed by Energy 11 Operating Company, LLC in favor of Kaiser-Francis Management Company, L.L.C. (incorporated by reference from Exhibit 10.1 to the Partnership's Form 8-K filed on March 31, 2017).
10.5	First Amendment dated July 21, 2017 to Secured Promissory Note dated March 31, 2017 between Energy 11 Operating Company, LLC and Kaiser-Francis Management Company, L.L.C. (incorporated by reference from Exhibit 10.5 to the Partnership's Form 10-Q filed on August 11, 2017).
10.6	Revolver Loan Agreement dated as of November 21, 2017 between Energy 11, L.P. and Energy 11 Operating Company, LLC, collectively as borrowers, and Bank SNB, as lender (incorporated by reference from Exhibit 10.6 to the Partnership's Current Report on Form 8-K filed on November 22, 2017).
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*
99.1	Report of Pinnacle Energy Services, LLC, Independent Petroleum Consultants.*
101	Interactive Data Files.*

*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 11, L.P.

By: Energy 11 GP, LLC, its General Partner

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

Date: March 8, 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)	March 8, 2018
/s/ David S. McKenney David S. McKenney	Director, Chief Financial Officer (principal financial and accounting officer)	March 8, 2018
/s/ Anthony F. Keating III Anthony F. Keating III	Director, Co-Chief Operating Officer	March 8, 2018
/s/ Michael J. Mallick Michael J. Mallick	Director, Co-Chief Operating Officer	March 8, 2018

EXHIBIT 21.1

Subsidiaries of the Partnership

The following are wholly owned subsidiaries of Energy 11, L.P.:

Energy 11 Operating Company, LLC (Formed in Delaware)
Energy 11 Management, 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 11, 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: March 8, 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 11, 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: March 8, 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 11, 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: March 8, 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 11, 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: March 8, 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.

Exhibit 99.1

ENERGY 11, LP

5815 N. WESTERN AVENUE
OKLAHOMA CITY, OK 73118

RESERVES AND ECONOMIC EVALUATION
YEAR END 2017 RESERVES

NON-OPERATED ASSETS LOCATED WITHIN THE SANISH OIL FIELD LOCATED IN MOUNTRAIL COUNTY, NORTH DAKOTA

EFFECTIVE: JANUARY 1, 2018
SEC PRICING

Prepared: January 24, 2018

By: John Paul (J.P.) Dick, P.E.
Candace Cantrell, P.E.

PINNACLE ENERGY

January 24, 2018

ENERGY 11, LP
5815 N. Western Avenue
Oklahoma City, OK 73118

Re: Reserve & Economic Evaluation
Non-Operated Assets in the Sanish Oil Field
Mountrail County, North Dakota
Year End 2017 Reserves – SEC Price

EXECUTIVE SUMMARY

An engineering and economic evaluation was prepared for oil and gas reserves located in the Williston Basin Sanish Field in Mountrail County, North Dakota in which Energy 11, LP owns a working and/or royalty interest. The oil and gas reserves associated with these properties were evaluated and classified as Proved Reserves in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC). The Proved reserves include two hundred fifteen (215) horizontal Proved Developed Producing (PDP) wells, 6 (six) horizontal Proved Non-Producing (PNP) wells and fifty-one (51) Proved Undeveloped (PUD) horizontal locations targeting the Bakken Shale and Three Forks formation in multiple sections/units. Also included in the attached economic reports is one (1) Proved Developed Shut-In (PDSI) wells; however, this well was given no value or reserves for this evaluation. Remaining reserves, future cashflow, and present worth values were calculated as of January 1, 2018. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Energy 11.

The reserves and economics were determined using SEC YE2017 pricing as of January 1, 2018. **Table 1** summarizes the estimated net reserves and future net revenue (cashflow), discounted and undiscounted, to the Energy 11 interest in these properties.

Table 1 - Net Reserve and Economic Report Summary

Reserve Category	# Wells	Oil (Mbbl)	Gas (MMcf)	NGL (Mbbl)	Net Cashflow ($M)	PV 10% ($M)
Proved	**273**	**17,792**	**20,225**	**3,535**	**471,226**	**185,905**
PDP	215	9,264	10,884	1,902	251,251	127,481
PDSI	1	0	0	0	0	0
PNP	6	377	416	73	8,448	2,978
PUD	51	8,151	8,925	1,560	211,527	55,446

ECONOMIC EVALUATION

FUTURE INCOME

Future net revenue in this report includes deductions for state production taxes. Future net cashflow is after deducting state production taxes, future capital investments, and lease operating expenses but before consideration of any state and/or federal income taxes. For purposes of this evaluation, future capital investments include costs for drilling, completing, and equipping new wells. Abandonment costs of 100 M$ at the end of well life for each well have been included in this evaluation. The future net cashflow has not been adjusted for any outstanding loans that may exist, cash on hand, or undistributed income. Future net cashflow has been discounted at an annual rate of ten percent (10%) to determine its "present worth." The present worth is shown to indicate the effect of time on the value of money. Future net revenue (cashflow) presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties evaluated.

INTERESTS

Well and leasehold interests were provided by Energy 11 and were assumed to be correct. The non-operated interests average approximately 26% working interest and 21% net revenue interest.

PRODUCT PRICING

Per SEC rules, the SEC pricing is determined by calculating the unweighted arithmetic average of the first-day-of-the-month NYMEX oil and gas pricing for the prior twelve calendar months (January 2017 through December 2017) to the date of evaluation. All prices are held constant throughout the lives of the properties. For year-end 2017, the unweighted arithmetic average NYMEX (Cushing) oil price is 51.34 $/bbl and the average NYMEX (Henry Hub) natural gas price is 2.98 $/MMbtu. Prices were adjusted for quality, basis, energy content, transportation fees and other market differentials based on an analysis of revenue data.

Differentials to NYMEX pricing were calculated by examining revenue statements and financial information to determine deductions or increases to oil and gas prices due to Btu, differentials, NGLs, processing, transportation, and/or contract terms. The pricing adjustments and differentials include the following:

Oil Price differential of -6.50 $/bbl
Natural Gas Liquids (NGL) determined using 33% of Oil Price
Residue Natural Gas differential of -2.86 $/Mcf
Natural Gas shrink of 25.4%
Natural Gas Liquid Yield of 130.39 bbl/MMcf wet gas

Including the adjustments for quality, basis, energy content, transportation fees and other market differentials, the average realized prices held constant throughout the lives of the properties were 44.84 $/bbl oil, 0.12 $/Mcf natural gas and 16.94 $/bbl NGL.

EXPENSES

An expense model was provided by Energy 11 to model the actual well life expense changes for all wells and undeveloped locations. Expenses were not escalated.

25,000 $/month for 1.5 years then…
20,000 $/month for 1.5 years then…
15,000 $/month for 1 year then…
12,000 $/month for 1 year then…
10,000 $/month for 3 years then…
7,500 $/month for 5 years then…
6,800 $/month until ECL

FUTURE WELL INVESTMENTS

Capital expenses for the future locations were estimated to be 6.4 MM$/well, which is consistent with recent, actual industry drilling and completion costs for wells within the prospective area. Capital timing for future development work was provided by Energy 11. Pinnacle cannot be responsible for capital costs that exceed or are less than these estimates.

RESERVE DETERMINATION

RESERVE DISCUSSION

Remaining recoverable reserves are those quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty depending primarily on the amount of reliable geologic and engineering (production, pressure) data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty is conveyed by classifying reserves as Proved (highly certain) or Non-Proved (less certain). The estimated reserves and revenues shown in this report were determined by SEC standards for Proved Developed Producing (PDP) wells, Proved Non-Producing (PNP) wells, and Proved Undeveloped (PUD) locations.

Proved reserves are those quantities of petroleum which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs with defined limits and under current economic conditions, operating methods, and government regulations. Changes in any of these variables could materially change the reserves actually recovered.

Proved reserves are further classified as Proved Developed Producing (PDP) which is assigned to wells with sufficient production history to allow material balance and decline curve analysis to be the primary methods of estimation. PDP reserves are the most reliable reserves, generally with a high degree of confidence (>90%) that actually recovered quantities will equal or exceed published reserve estimates.

Proved Non-Producing (PNP) reserves include zones that have been penetrated by drilling but have not produced or have not produced in sufficient quantities to allow material balance or decline curve analysis with a high degree of confidence. This category includes wells awaiting completion.

Proved Undeveloped (PUD) reserves are those quantities of petroleum that are estimated to be recovered from undrilled acreage (locations) in a continuous portion of the Proved Developed reservoir as defined by directly offsetting Proved Developed (PDP) wells and geological interpretations. The Proved Undeveloped and Non-Producing wells are forecasted based on geological data presented, volumetric calculations, and analog comparisons to existing completions.

GENERAL

The reserves and values included in this report are estimates only and should not be construed as being exact quantities. The reserve estimates were performed using accepted engineering practices and were primarily based on historical rate decline analysis for existing producers. When possible and practical, volumetric calculations and analogies were integrated into the reserve estimates. As additional pressure and production performance data becomes available, reserve estimates may increase or decrease in the future. The revenue from such reserves and the actual costs related may be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the prices actually received for the reserves included in this report and the costs incurred in recovering such reserves may vary from the price and cost assumptions referenced. Therefore, in all cases, estimates of reserves may increase or decrease as a result of future operations. We consider all assumptions, data, and procedures utilized in this report appropriate for the purpose of this report.

In evaluating the information available for this analysis, items excluded from consideration were all matters as to which legal or accounting interpretation, rather than engineering interpretation, may be controlling. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering data and such conclusions necessarily represent only informed professional judgments.

Pinnacle Energy Services, LLC is an established petroleum engineering consulting firm. We hereby confirm that neither this firm, its affiliates, nor any of its employees, members, officers, or directors has, or is committed to acquire any interest, directly or indirectly, in the properties covered by this report, in any partnership, any general partner of the partnerships, nor is this firm or any employee, member or officer, or director thereof otherwise affiliated with any partnership or any such general partner. This report was completely independently prepared by Pinnacle Energy Services, LLC and our engagement and payment for services in connection with this report is independent of the outcome and not on a contingent basis.

The titles to the properties have not been examined nor has the actual degree or type of interest owned been independently confirmed. A field inspection of the properties is not usually considered necessary for the purpose of this report.

All information reviewed and utilized will be retained and is available for review by authorized parties at any time. Information used to prepare the evaluation was provided by Energy 11, LP, and was supplemented by public and in-house data. Pinnacle Energy Services, LLC can take no responsibility for the accuracy of the data used in the analysis, whether gathered from public sources or otherwise.

Pinnacle Energy Services, LLC

/s/ John Paul Dick
John Paul (J.P.) Dick, P.E.
Petroleum Engineer

/s/ Candace Cantrell
Candace Cantrell, P.E.
Petroleum Engineer