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

FORM 10-Q

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

For the quarterly period ended March 31, 2018

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM _______ TO _______

Commission File Number 000-55615

Energy 11, L.P.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**46-3070515** (IRS Employer Identification No.)
120 W 3rd Street, Suite 220 **Fort Worth, Texas** (Address of principal executive offices)	**76102** (Zip Code)

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

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

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

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

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

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

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

As of April 30, 2018, the Partnership had 18,973,474 common units outstanding.

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

Energy 11, L.P.
Consolidated Balance Sheets
(Unaudited)

	March 31, 2018	December 31, 2017
Assets		
Cash and cash equivalents	$ 2,734,467	$ 11,090,846
Oil, natural gas and natural gas liquids revenue receivable	7,035,455	6,219,193
Other current assets	158,803	162,930
Total Current Assets	9,928,725	17,472,969
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization of $28,885,163 and $24,934,190, respectively	322,409,071	321,766,616
Total Assets	$ 332,337,796	$ 339,239,585
Liabilities		
Accounts payable and accrued expenses	$ 4,476,869	$ 2,733,131
Derivative liability	1,715,642	1,026,965
Total Current Liabilities	6,192,511	3,760,096
Revolving credit facility	13,000,000	20,000,000
Asset retirement obligations	1,243,676	1,226,879
Total Liabilities	20,436,187	24,986,975
Partners' Equity		
Limited partners' interest (18,973,474 common units issued and outstanding, respectively)	311,903,336	314,254,337
General partner's interest	(1,727)	(1,727)
Class B Units (62,500 units issued and outstanding, respectively)	-	-
Total Partners' Equity	311,901,609	314,252,610
Total Liabilities and Partners' Equity	$ 332,337,796	$ 339,239,585

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Operations
(Unaudited)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Oil, natural gas and natural gas liquids revenues	$ 13,067,734	$ 10,141,266
Operating costs and expenses		
Production expenses	2,934,666	2,731,854
Production taxes	1,075,125	857,733
General and administrative expenses	381,616	501,741
Depreciation, depletion, amortization and accretion	3,967,770	3,256,258
Total operating costs and expenses	8,359,177	7,347,586
Operating income	4,708,557	2,793,680
Loss on derivatives	(1,162,255)	-
Interest expense, net	(220,857)	(172,609)
Total other expense, net	(1,383,112)	(172,609)
Net income	$ 3,325,445	$ 2,621,071
Basic and diluted net income per common unit	$ 0.18	$ 0.17
Weighted average common units outstanding - basic and diluted	18,973,474	15,809,588

See notes to consolidated financial statements.

Energy 11, L.P.
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Cash flow from operating activities:		
Net income	$ 3,325,445	$ 2,621,071
Adjustments to reconcile net income to cash from operating activities:		
Depreciation, depletion, amortization and accretion	3,967,770	3,256,258
Loss on mark-to-market of derivatives	688,677	-
Non-cash expenses, net	11,352	23,449
Changes in operating assets and liabilities:		
Oil, natural gas and natural gas liquids revenue receivable	(816,262)	(2,977,569)
Other current assets	(5,380)	22,933
Accounts payable and accrued expenses	(118,935)	717,514
Net cash flow provided by operating activities	7,052,667	3,663,656
Cash flow from investing activities:		
Cash paid for acquisition of oil and natural gas properties	-	(98,327,930)
Additions to oil and natural gas properties	(2,730,755)	(114,612)
Net cash flow used in investing activities	(2,730,755)	(98,442,542)
Cash flow from financing activities:		
Cash paid for loan costs	(1,845)	-
Payments on revolving credit facility	(7,000,000)	-
Net proceeds related to issuance of units	-	58,504,622
Distributions paid to limited partners	(5,676,446)	(5,488,149)
Payments on note payable	-	(40,000,000)
Net cash flow used in financing activities	(12,678,291)	13,016,473
Decrease in cash and cash equivalents	(8,356,379)	(81,762,413)
Cash and cash equivalents, beginning of period	11,090,846	86,800,596
Cash and cash equivalents, end of period	$ 2,734,467	$ 5,038,183
Interest paid	$ 231,792	$ 158,904
Supplemental non-cash information:		
Note payable assumed in Acquisition No. 2	-	40,000,000
Note payable assumed in Acquisition No. 3	-	33,000,000

See notes to consolidated financial statements.

Energy 11, L.P.
Notes to Consolidated Financial Statements
March 31, 2018
(Unaudited)

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 19.0 million common units sold for gross proceeds of $374.2 million and proceeds net of offering costs of $349.6 million.

As of March 31, 2018, the Partnership owned an approximate 26-27% non-operated working interest in 217 currently producing wells, 4 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.

The Partnership’s fiscal year ends on December 31.

Note 2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying unaudited financial statements have been prepared in accordance with the instructions for Article 10 of SEC Regulation S-X. Accordingly, they do not include all of the information required by generally accepted accounting principles (“GAAP”) in the United States. In the opinion of management, all adjustments (consisting of normal recurring accruals) considered necessary for a fair presentation have been included. These unaudited financial statements should be read in conjunction with the Partnership’s audited consolidated financial statements included in its 2017 Annual Report on Form 10-K. Operating results for the three months ended March 31, 2018 are not necessarily indicative of the results that may be expected for the twelve-month period ending December 31, 2018.

Use of Estimates

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

Net Income Per Common Unit

Basic net income per common unit is computed as net income divided by the weighted average number of common units outstanding during the period. Diluted net income per common unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no common units with a dilutive effect for the three months ended March 31, 2018 and 2017. As a result, basic and diluted outstanding common units were the same. The Class B units and Incentive Distribution Rights, as defined below, are not included in net income per common unit until such time that it is probable Payout (as discussed in Note 8) will occur.

Recently Adopted Accounting Standards

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“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. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. The Partnership adopted this standard on January 1, 2018 using the modified retrospective approach.

Impact of Topic 606 Adoption

In accordance with Topic 606, the Partnership completed a detailed review of its revenue contracts, which represent all of the Partnership's revenue streams, including oil, natural gas and natural gas liquids sales, to determine the effect of the new standard for the three months ended March 31, 2018. The Partnership did not record a change to its opening retained earnings as of January 1, 2018, as there was no material change to the timing or pattern of revenue recognition due to the adoption of ASC 606. The Partnership is bound by a joint operating agreement with the operator of each of its producing wells. Under the joint operating agreement, the Partnership's proportionate share of production is marketed at the discretion of the operators. 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 typically satisfies its performance obligations upon transfer of control of its products and records the related revenue in the month production is delivered to the purchaser. Settlement receipts for sales of oil, natural gas and natural gas liquids may not be received for two to three months after the date production is delivered by the operator, and as a result, the Partnership is required to estimate the amount of production delivered by the operator and the price that will be received for the sale of the product. The Partnership records the differences between estimates and the actual amounts received for product sales in the month that payment is received from the operator. Historically, differences between the Partnership's revenue estimates and actual revenue received have not been significant.

The following table disaggregates the Partnership's revenue streams that are summarized as "Oil, natural gas and natural gas liquids revenues" on the consolidated statements of operations for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Oil revenues	$ 10,644,693	$ 8,443,214
Natural gas revenues	932,998	670,282
Natural gas liquids revenues	1,490,043	1,027,770
	$ 13,067,734	$ 10,141,266

Recently Issued Accounting Standards

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 Natural 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. 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 for Acquisition No. 2 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. 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 for Acquisition No. 3 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%.

The following unaudited pro forma financial information for the three-month period ended March 31, 2017 has been prepared as if Acquisitions No. 2 and No. 3 of the Sanish Field Assets had occurred on January 1, 2017. 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.

	Three Months Ended March 31, 2017
Revenues	$ 12,456,650
Net income	$ 2,869,027

In October and November 2017, the Partnership elected to participate in the drilling and completion of six new wells. Two of the six wells were completed in March 2018. These two wells were completed and are being operated by Whiting, and the Partnership has an estimated approximate 29% non-operated working interest in these two wells. The other 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. These four wells are anticipated to be completed in the second quarter of 2018. In total, the Partnership's capital expenditures for the drilling and completion of the six wells discussed above are estimated to be approximately $7.0 million, of which approximately $5.3 million had been incurred as of March 31, 2018, including approximately $4.0 million in the first quarter of 2018.

Note 4. Debt

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"). The Amended Note also 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.

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 March 31, 2018, the borrowing base was $30 million and the interest rate for the Credit Facility was 5.06%.

The Credit Facility is available to provide additional liquidity for capital investments, including the completion of the four 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 March 31, 2018.

As of March 31, 2018, the outstanding balance on the Credit Facility was $13.0 million, which approximates its fair market value. The Partnership estimated the fair value of its Credit Facility 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. Asset Retirement Obligations

The Partnership records an asset retirement obligation ("ARO") and capitalizes the asset retirement costs in oil and natural gas properties in the period in which the asset 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 changes in the aggregate ARO are as follows:

	2018	2017
Balance as of January 1	$ 1,226,879	$ 70,623
Liabilities incurred - Acquisition No. 2	-	781,628
Liabilities incurred - Acquisition No. 3	-	289,827
Revisions	-	36,625
Accretion expense	16,797	11,172
Balance as of March 31	$ 1,243,676	$ 1,189,875

Note 6. 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 three months ended March 31, 2018 and 2017, 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 March 31, 2017, 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 March 31, 2018.

	Fair Value Measurements at March 31, 2018		
	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	-	(1,715,642)	-
Total	$ -	$ (1,715,642)	$ -

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 March 31, 2018. See additional detail in Note 7. 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 7. 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.

At March 31, 2018 and December 31, 2017, the Partnership's costless collar derivative instruments were in a net loss position; therefore, the current Derivative liability on the consolidated balance sheets was approximately $1.7 million and $1.0 million, respectively, which approximated fair value. 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 recognized a total net loss on its derivative instruments of approximately $1.2 million for the three months ended March 31, 2018, which was recorded in the consolidated statements of operations as Loss on derivatives. The loss was comprised of (i) $0.5 million of losses the Partnerships recognized on settled derivatives during the period and (ii) $0.7 million of a mark-to-market loss incurred on derivative instruments outstanding at period end.

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 6. Fair Value of Financial Instruments.

The following table presents settlements on matured derivative instruments and non-cash losses on open derivative instruments for the period presented. Settlements on matured derivatives below reflect losses on derivative contracts which matured during the period, calculated as the difference between the contract price and the market settlement price. Non-cash losses below represent the change in fair value of derivative instruments which were held at period-end.

	Three Months Ended March 31, 2018
Settlements on matured derivatives	$ (473,578)
Loss on mark-to-market of derivatives	(688,677)
Loss on derivatives	$ (1,162,255)

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. The follow table reflects the open costless collar agreements as of March 31, 2018.

Settlement Period	Basis	Oil (Barrels)	Floor / Ceiling Prices ($)	Fair Value of Asset / (Liability) at March 31, 2018
04/01/18 - 12/31/18	NYMEX	216,000	$ 52.00 / 57.05	$ (1,500,989)
04/01/18 - 12/31/18	NYMEX	27,000	$ 55.00 / 61.35	(93,432)
04/01/18 - 12/31/18	NYMEX	27,000	$ 55.00 / 62.25	(78,638)
04/01/18 - 12/31/18	NYMEX	27,000	$ 56.00 / 65.25	(33,223)
04/01/18 - 12/31/18	NYMEX	27,000	$ 58.00 / 66.50	(9,360)
				$ (1,715,642)

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 8. 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).

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 David Lerner Associates, Inc. (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 the best-efforts offering, the total contingent fee is a maximum of 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 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 unit, regardless of the amount paid for the 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%).

For the three months ended March 31, 2018 and 2017, the Partnership paid distributions of $0.299178 and $0.349041 per common unit, or $5.7 million and $5.5 million, respectively.

In the fourth quarter of 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 six percent 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 March 31, 2018, the accumulated unpaid distributions totaled $0.084383 per common unit, or approximately $1.6 million.

In March 2018, the General Partner approved an increase to the annualized distribution rate back to seven percent based on a limited partner's Net Investment Amount. The seven percent distribution rate was effective with the April 26, 2018 distribution.

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.

For the three months ended March 31, 2018 and 2017, approximately $71,000 and $80,000 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 March 31, 2018, approximately $71,000 was due to a member of the General Partner and is included in Accounts payable and accrued expenses on the consolidated balance sheets.

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 gives 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 are split evenly between the two partnerships and any direct third-party costs are paid by the party receiving the services. The shared costs are 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 Partnership leases office space in Oklahoma City, Oklahoma on a month-to-month basis from an affiliate of the General Partner. For the three months ended March 31, 2018 and 2017, the Partnership paid $25,611 to the affiliate of the General Partner.

The office space is shared between the Partnership and ER12; therefore, under the cost sharing agreement, the monthly payment of $8,537 is split between the two partnerships. In addition to the office space, the cost sharing agreement reduces the costs to the Partnership for accounting and asset management services provided through a member of the General Partner noted above. The compensation due to Clifford J. Merritt, President of the General Partner, is also a shared cost between the Partnership and ER12. For the three months ended March 31, 2018, approximately $47,000 of expenses subject to the cost sharing agreement were incurred by the Partnership and will be reimbursed by ER12. At March 31, 2018, the approximately $47,000 due to the Partnership from ER12 is included in Other current assets in the consolidated balance sheets.

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. With the fees received from ER12 for advisory and consulting services, REI paid certain personnel utilized by the Partnership, including Mr. Merritt, an aggregate total of $500,000.

Note 10. Subsequent Events

In April 2018, the Partnership declared and paid $2.0 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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:

- references to future success in the Partnership's drilling and marketing activities;
- the Partnership's business strategy;
- estimated future distributions;
- estimated future capital expenditures;
- 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 that the Partnership's operations on properties acquired 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 or refinancing debt for the Partnership's drilling activities in a timely manner and on terms that are consistent with what the Partnership projects;
- 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 the Partnership's 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.

The following discussion and analysis should be read in conjunction with the Partnership's Unaudited Consolidated Financial Statements and Notes thereto, appearing elsewhere in this Quarterly Report on Form 10-Q, as well as the information contained in the Partnership's Annual Report on Form 10-K for the year ended December 31, 2017.

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 March 31, 2018, the Partnership owned an approximate 26-27% non-operated working interest in 217 currently producing wells, 4 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. Two of the six wells were completed in March 2018. These two wells were completed and are being operated by Whiting, and the Partnership has an estimated approximate 29% non-operated working interest in these two wells. The other 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. These four wells are anticipated to be completed in the second quarter of 2018. In total, the Partnership’s capital expenditures for the drilling and completion of the six wells discussed above are estimated to be approximately $7.0 million, of which approximately $5.3 million had been incurred as of March 31, 2018, including approximately $4.0 million in the first quarter of 2018.

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. In 2017, monthly average oil prices (based on daily settlements of monthly contracts traded on the NYMEX) ranged from a low of $45.18 per barrel in June 2017 to a high of $57.88 in December 2017. The monthly average of $63.70 per barrel of oil in January 2018 represented the highest monthly average since November 2014.

From January 1, 2017 through December 31, 2017, natural gas prices stabilized between approximately $2.81 per MMBtu (December 2017) and $3.30 per MMBtu (January 2017). For the three months ended March 31, 2018, the average price for natural gas was $3.03.

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 three months ended March 31, 2018 and 2017.

	Three Months Ended March 31,	
	2018	2017
Average market closing prices (1)		
Oil (per Bbl)	$ 62.91	$ 51.78
Natural gas (per Mcf)	$ 3.08	$ 3.02

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

The Partnership's 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.

Results of Operations

In evaluating financial condition and operating performance, the most important indicators on which the Partnership focuses are (1) total quarterly production in barrel of oil equivalent ("BOE") units, (2) average sales price per unit for oil, natural gas and natural gas liquids, (3) production costs per BOE and (4) capital expenditures.

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 three months ended March 31, 2018 and 2017 are impacted by these transactions. The following is a summary of the results from operations, including production, of the Partnership's non-operated working interest for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31,			
	2018	Percent of Revenue	2017	Percent of Revenue
Total revenues	$ 13,067,734	100.0%	$ 10,141,266	100.0%
Production expenses	2,934,666	22.5%	2,731,854	26.9%
Production taxes	1,075,125	8.2%	857,733	8.5%
Depreciation, depletion, amortization and accretion	3,967,770	30.4%	3,256,258	32.1%
General, administration and other expense	381,616	2.9%	501,741	4.9%
Production (BOE):				
Oil	189,788		184,581	
Natural gas	39,381		31,424	
Natural gas liquids	39,360		34,223	
Total	268,529		250,228	
Average sales price per unit:				
Oil (per Bbl)	$ 56.09		$ 45.74	
Natural gas (per Mcf)	3.95		3.56	
Natural gas liquids (per Bbl)	37.86		30.03	
Combined (per BOE)	48.66		40.53	
Average unit cost per BOE:				
Production expenses	10.93		10.92	
Production taxes	4.00		3.43	
Depreciation, depletion and amortization	14.78		13.01	
Capital expenditures	$ 4,593,428		$ 175,583	

Oil, Natural Gas and NGL Revenues

For the three months ended March 31, 2018, revenues for oil, natural gas and NGL sales were $13.1 million. Revenues for the sale of crude oil were $10.6 million, which resulted in a realized price of $56.09 per barrel. Revenues for the sale of natural gas were $0.9 million, which resulted in a realized price of $3.95 per Mcf. Revenues for the sale of NGLs were $1.5 million, which resulted in a realized price of $37.86 per BOE of production. For the three months ended March 31, 2017, revenues for oil, natural gas and NGL sales were $10.1 million. Revenues for the sale of crude oil were $8.4 million, which resulted in a realized price of $45.74 per barrel. Revenues for the sale of natural gas were $0.7 million, which resulted in a realized price of $3.56 per Mcf. Revenues for the sale of NGLs were $1.0 million, which resulted in a realized price of $30.03 per BOE of production.

The Partnership benefited from increases in commodity prices for oil, natural gas and NGLs during the first three months of 2018, as market prices during the first quarter of 2018 were higher than prices in the first quarter of 2017. Price gains were partially offset by the natural decline in production from existing wells. The Partnership expects to offset a portion of the natural decline in its production volumes in the second quarter of 2018 as the new six wells discussed above begin producing. Production for the Sanish Field Assets was approximately 3,000 BOE per day for the three months ended March 31, 2018. If the Partnership had completed Acquisitions 2 and 3 effective January 1, 2017, the Partnership estimates production for the Sanish Field Assets would have been approximately 3,400 BOE per day for the three months ended March 31, 2017.

Production is dependent on the investment in existing wells and the development of new wells. As noted above, the Partnership does not anticipate to realize any significant increases to overall production from new wells until the second quarter of 2018. 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 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 three months ended March 31, 2018 and 2017, production expenses were $2.9 million and $2.7 million, respectively, and production expenses per BOE of production were $10.93 and $10.92, respectively. The Partnership anticipates production expenses may increase in the second and third quarters of 2018 due to (i) specific well workovers performed by the operator to return wells nearby recently completed wells to full production and (ii) the operator may complete certain well repair and maintenance in warmer spring and summer months in North Dakota.

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 for the first half of 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 three months ended March 31, 2018 and 2017 were $1.1 million (8.2% of revenue) and $0.9 million (8.5% 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 three months ended March 31, 2018 and 2017 was $4.0 million and $3.3 million, and DD&A per BOE of production was $14.78 and $13.01, respectively. The increase in DD&A expense per BOE of production is primarily due to the decrease of the Partnership's estimated proved undeveloped reserves ("PUDs") resulting from changes in the future drill schedule along with the Partnership's investment in new wells.

General and Administrative Costs

General and administrative costs for the three months ended March 31, 2018 and 2017 were $0.4 million and $0.5 million, respectively. The principal components of general and administrative expense are accounting, legal and consulting fees. The decline is primarily due to the cost sharing agreement discussed below.

Loss on Derivatives

In December 2017, January 2018 and March 2018, the Partnership entered into derivative contracts (costless collars) with the objective to manage the commodity price risk on a portion of anticipated 2018 oil production. The Partnership's loss on derivative instruments for the three months ended March 31, 2018 was $1.2 million. The loss is comprised of (i) $0.5 million of losses on settled derivatives during the period, and (ii) $0.7 million of a mark-to-market loss incurred on derivative instruments outstanding at period end. The Partnership's recognized losses on settled derivatives of $0.5 million represented 105,000 barrels of produced oil, resulting in a loss of $4.51 per barrel of oil.

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	324,000	53.33 / 59.31

Interest Expense

Interest expense, net, for the three months ended March 31, 2018 and 2017 was $0.2 million in each period. The primary component of Interest expense, net, during the three months ended March 31, 2018 was interest expense on the Credit Facility, described below, while the primary component during the three months ended March 31, 2017 was interest expense on the notes payable executed in conjunction with Acquisitions No. 2 and No. 3.

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, 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 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 income to Adjusted EBITDAX for the three months ended March 31, 2018 and 2017.

	Three Months Ended March 31, 2018	Three Months Ended March 31, 2017
Net income	$ 3,325,445	$ 2,621,071
Interest expense, net	220,857	172,609
Depreciation, depletion, amortization and accretion	3,967,770	3,256,258
Exploration expenses	-	-
Non-cash loss on mark-to-market of derivatives	688,677	-
Adjusted EBITDAX	$ 8,202,749	$ 6,049,938

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 new wells.

Financing

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.

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 March 31, 2018, the borrowing base was $30 million and the interest rate for the Credit Facility was 5.06%.

The Credit Facility is available to provide additional liquidity for capital investments, including the 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 March 31, 2018.

At March 31, 2018, the outstanding balance on the Credit Facility was $13.0 million.

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 "Note 8. Capital Contribution and Partners' Equity" in Part I, Item 1 of this Form 10-Q.

Distributions

For the three months ended March 31, 2018 and 2017, the Partnership paid distributions of $0.299178 and $0.349041 per common unit, or $5.7 million and $5.5 million, respectively. The Partnership generated $7.1 million and $3.7 million, respectively, in cash flow from operations for the three months ended March 31, 2018 and 2017.

In the fourth quarter of 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 March 31, 2018, the accumulated unpaid distributions totaled $0.084383 per common unit, or approximately $1.6 million.

In March 2018, the General Partner approved an increase to the annualized distribution rate back to seven percent based on a limited partner's Net Investment Amount. The seven percent distribution rate was effective with the April 26, 2018 distribution. 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.

Oil and Natural Gas Properties

The Partnership incurred approximately $4.6 million and $0.2 million in capital expenditures for the three months ended March 31, 2018 and 2017, respectively. The Partnership estimates that approximately $1.7 million of estimated capital expenditures remain in conjunction with the drilling and completion of the six new wells discussed above. Including the remaining capital costs for the six new wells, the Partnership expects to invest approximately $3.0 to $5.0 million in capital expenditures during the remainder 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 the remainder of 2018 and current estimated capital expenditures could be significantly different from amounts actually invested.

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 I, Item 1 of this Form 10-Q.

Subsequent Events

In April 2018, the Partnership declared and paid $2.0 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Information regarding the Partnership's hedging programs to mitigate commodity risks is contained in Item 1 – Financial Statements (Unaudited) and Notes to Consolidated Financial Statements: Note 7. Risk Management and Item 2 – Management's Discussion and Analysis of Financial Condition and Results of Operations, appearing elsewhere within this Quarterly Report on Form 10-Q.

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 – Financial Statements (Unaudited) and Notes to Consolidated Financial Statements: Note 4. Debt and Item 2 – Management's Discussion and Analysis of Financial Condition and Results of Operations, appearing elsewhere within this Quarterly Report on Form 10-Q.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

In accordance with Exchange Act Rule 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 the 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 concluded that the Partnership's disclosure controls and procedures were effective as of March 31, 2018 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 the Chief Financial Officer of the General Partner, as appropriate, to allow timely decisions regarding required disclosure.

Change in Internal Controls Over Financial Reporting

There have not been any changes in the Partnership's internal controls over financial reporting that occurred during the quarterly period ended March 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Partnership's internal controls over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

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

Item 1A. Risk Factors

For a discussion of the Partnership's potential risks and uncertainties, see the section titled "Risk Factors" in the 2017 Form 10-K. There have been no material changes to the risk factors previously disclosed in the 2017 Form 10-K.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

Not applicable.

Item 3. Defaults upon Senior Securities.

Not applicable.

Item 4. Mine Safety Disclosures.

Not applicable.

Item 5. Other Information.

Not applicable.

Item 6. Exhibits.

Exhibit No.	Description
31.1	Certification of Chief Executive Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002*
31.2	Certification of Chief Financial Officer Pursuant to Section 302 of Sarbanes-Oxley Act of 2002*
32.1	Certification of Chief Executive Officer Pursuant to Section 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
32.2	Certification of Chief Financial Officer Pursuant to Section 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002*
101	The following materials from Energy 11, L.P.'s Quarterly Report on Form 10-Q for the quarter ended March 31, 2018 formatted in XBRL (eXtensible Business Reporting Language): (i) the Balance Sheets, (ii) the Statements of Operations, (iii) the Statements of Cash Flows, and (iv) related notes to these financial statements, tagged as blocks of text and in detail*

*Filed herewith.

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 G.P., LLC, its General Partner

By: /s/ Glade M. Knight
Glade M. Knight
Chief Executive Officer
(Principal Executive Officer)

By: /s/ David S. McKenney
David S. McKenney
Chief Financial Officer
(Principal Financial and Accounting Officer)

Date: May 11, 2018

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 Quarterly Report on Form 10-Q 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: May 11, 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 McKenney, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q 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: May 11, 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 Quarterly Report on Form 10-Q (the "Form 10-Q") for the three months ended March 31, 2018 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-Q 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-Q 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: May 11, 2018

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

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 Quarterly Report on Form 10-Q (the “Form 10-Q”) for the three months ended March 31, 2018 of Energy 11, L.P. (the “Partnership”). I, David McKenney, the Chief Financial Officer of the Partnership, certify that, based on my knowledge:

(1) The Form 10-Q 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-Q 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: May 11, 2018

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