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Energy 11, L.P. (Filer) CIK: 0001581552

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Document And Entity Information - USD ($)	12 Months Ended		
	Dec. 31, 2016	Mar. 03, 2017	Jun. 30, 2016
Document and Entity Information [Abstract]			
Entity Registrant Name	Energy 11, L.P.		
Document Type	10-K		
Current Fiscal Year End Date	--12-31		
Entity Common Stock, Shares Outstanding		16,690,442	
Entity Public Float			$ 0
Amendment Flag	false		
Entity Central Index Key	0001581552		
Entity Current Reporting Status	Yes		
Entity Voluntary Filers	No		
Entity Filer Category	Smaller Reporting Company		
Entity Well-known Seasoned Issuer	No		
Document Period End Date	Dec. 31, 2016		
Document Fiscal Year Focus	2016		
Document Fiscal Period Focus	FY		

Consolidated Balance Sheets - USD ($)	Dec. 31, 2016	Dec. 31, 2015
Assets		
Cash and cash equivalents	$ 86,800,596	$ 3,287,054
Accounts receivable:		
Oil, natural gas and natural gas liquids revenues	2,718,296	1,417,751
Acquisition post-closing receivable	0	1,556,530
Other current assets	10,038,221	0
Total Current Assets	99,557,113	6,261,335
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization; December 31, 2016, $9,908,800; December 31, 2015, $391,624	151,554,972	158,895,191
Total Assets	251,112,085	165,156,526
Liabilities and Partners’ Equity		
Note payable	0	81,684,758
Contingent consideration	0	4,743,752
Accounts payable and accrued		

expenses	2,693,023	3,449,442
Total Current Liabilities	2,693,023	89,877,952
Limited partners' interest (14,582,963 common units and 4,486,625 common units issued and outstanding at December 31, 2016 and December 31, 2015, respectively)	248,420,789	75,280,301
General partners' interest	(1,727)	(1,727)
Class B units (62,500 and 100,000 units issued and outstanding at December 31, 2016 and December 31, 2015, respectively)	0	0
Total Partners' Equity	248,419,062	75,278,574
Total Liabilities and Partners' Equity	$ 251,112,085	$ 165,156,526

Consolidated Balance Sheets (Parentheticals) - USD ($)	Dec. 31, 2016	Dec. 31, 2015
Oil and natural gas properties, accumulated depreciation, depletion and amortization (in Dollars)	$ 9,908,800	$ 391,624
Limited partners' interest, common units issued	14,582,963	4,486,625
Limited partners' interest, common units outstanding	14,582,963	4,486,625
Class B Units, units issued	62,500	100,000
Class B Units, units outstanding	62,500	100,000

Consolidated Statements of Operations - USD ($)	12 Months Ended		
	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Revenue			
Oil, natural gas and natural gas liquids revenues	$ 20,365,338	$ 703,806	$ 0
Operating costs and expenses			
Lease operating expenses	3,801,312	149,072	0
Gathering and processing expenses	2,009,799	18,139	0
Production taxes	1,870,212	74,460	0
Management fees	886,306	252,524	0
Acquisition related costs	77,550	313,366	0
General and administrative expenses	1,291,053	745,884	163,595
Depreciation, depletion and amortization	9,526,865	392,084	0
Total operating costs and expenses	19,463,097	1,945,529	163,595
Operating income (loss)	902,241	(1,241,723)	(163,595)
Interest expense, net	(6,132,805)	(321,093)	0
Net loss	$ (5,230,564)	$ (1,562,816)	$ (163,595)
Basic and diluted net loss per common unit (in Dollars per share)	$ (0.69)	$ (1.70)	$ 0
Weighted average common units outstanding - basic and diluted (in Shares)	7,538,180	920,668	0

Consolidated Statements of Partners' Equity - USD ($)	Total	Limited Partner [Member]	General Partner [Member]	Capital Unit, Class B [Member]
Balance at Dec. 31, 2013	$ (9,056)	$ (8,965)	$ (91)	$ 0
Distributions declared and to common units paid	0			

Net Loss	(163,595)	(161,959)	(1,636)	
Balance at Dec. 31, 2014	(172,651)	(170,924)	(1,727)	
Net proceeds from issuance of common units	78,286,761	78,286,761		
Distributions to organizational limited partner	(990)	(990)		
Distributions declared and to common units paid	(1,271,730)	(1,271,730)		
Net Loss	(1,562,816)	(1,562,816)		
Balance at Dec. 31, 2015	75,278,574	75,280,301	(1,727)	0
Net proceeds from issuance of common units	188,820,033	188,820,033		
Distributions declared and to common units paid	(10,448,981)	(10,448,981)		
Net Loss	(5,230,564)	(5,230,564)		
Balance at Dec. 31, 2016	$ 248,419,062	$ 248,420,789	$ (1,727)	$ 0

Consolidated Statements of Partners' Equity (Parentheticals) - $ / shares	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Distributions declared and paid, per unit	$ 1.400000	$ 0.510138

Consolidated Statements of Cash Flows	12 Months Ended		
	Dec. 31, 2016 USD ($)	Dec. 31, 2015 USD ($)	Dec. 31, 2014 USD ($)
Cash flow from operating activities:			
Net loss	$ (5,230,564)	$ (1,562,816)	$ (163,595)
Adjustments to reconcile net loss to cash from operating activities:			
Depreciation, depletion and amortization	9,526,865	392,084	0
Non-cash expenses, net	4,017,238	175,424	0
Accounts receivable oil, natural gas and natural gas liquids revenues	(2,004,351)	(703,806)	0
Other current assets	(38,221)	0	0
Accounts payable and accrued expenses	678,417	653,106	0
Due to general partner member	0	(158,641)	163,595
Net cash flow provided by (used in) operating activities	6,949,384	(1,204,649)	0
Cash flow from investing activities:			
Cash paid for acquisition of oil, natural gas and natural gas liquids properties	(1,000,000)	(60,000,000)	0
Deposit for potential acquisition	(10,000,000)	0	0
Additions to oil and natural gas properties	(1,644,186)	0	0
Net cash flow used in investing activities	(12,644,186)	(60,000,000)	0
Cash flow from financing activities:			
Cash paid for deferred loan costs	(250,000)	0	0
Net proceeds related to issuance of units	188,825,158	78,308,749	0
Distributions paid to limited partners	(10,448,981)	(1,271,730)	0
Payments on note payable	(88,917,833)	(12,545,410)	0
Net cash flow provided by financing activities	89,208,344	64,491,609	0
Increase in cash and cash equivalents	83,513,542	3,286,960	0
Cash and cash equivalents, beginning of period	3,287,054	94	94

Cash and cash equivalents, end of period	86,800,596	3,287,054	94
Interest paid	2,171,573	173,711	0
Supplemental non-cash information:			
Increase in note payable, payment of contingent consideration	5,000,000	0	0
Decrease in note payable, settlement of pre-close activity	1,082,167	0	0
Note payable assumed in acquisition	0	97,545,410	0
Contingent consideration in acquisition	0	4,725,448	0
Deferred purchase price of acquisition	0	1,702,203	0
Accounts receivable from seller in acquisition, net of assumed payables	0	1,395,883	0
Accrued deferred offering costs and other assets	$ 0	$ 0	$ 1,181,442

Partnership Organization	12 Months Ended
	Dec. 31, 2016
Disclosure Text Block [Abstract]	
Organization, Consolidation and Presentation of Financial Statements Disclosure [Text Block]	See below

Note 1. Partnership Organization

Energy 11, L.P. (together with its wholly-owned subsidiaries, the “Partnership”) was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership is offering common units of limited partner interest (the “common units”) on a best-efforts basis with the maximum offering up to $2,000,000,000 of capital, consisting of 100,263,158 common units. The Partnership’s offering was declared effective by the Securities and Exchange Commission (“SEC”) on January 22, 2015. As of August 19, 2015, the Partnership completed the sale of the minimum offering of 1,315,790 common units. The subscribers were admitted as Limited Partners of the Partnership at the initial closing of the offering and the Partnership has been admitting additional Limited Partners monthly since that time.

The Partnership’s primary investment objectives are to (i) acquire producing and non-producing oil and gas properties with development potential, 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 and will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties.

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”) is the dealer manager for the offering of the common units.

The Partnership’s fiscal year ends on December 31.

Summary of Significant Accounting Policies	12 Months Ended
	Dec. 31, 2016
Accounting Policies [Abstract]	
Significant Accounting Policies [Text Block]	See below

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”).

Cash and Cash Equivalents

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

Offering Costs

The Partnership is raising capital through an ongoing best-efforts offering of common units by David Lerner Associates, Inc., who receives a selling commission and a marketing expense allowance based on proceeds of the common units sold. Additionally, the Partnership has incurred other offering costs including legal, accounting and reporting services. These offering costs are recorded by the Partnership as a reduction of partners' equity. As of December 31, 2016 and 2015, the Partnership had sold 14.6 million and 4.5 million common units for gross proceeds of $286.4 million and $85.2 million, respectively, and proceeds net of offering costs of $267.1 million and $78.3 million, respectively.

Property and Depreciation, Depletion and Amortization

We account for our 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

We assess our 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, we recognize 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 we have an interest in may be similarly affected by changes in economic, industry or other conditions. At December 31, 2016, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2016, the Partnership's oil, natural gas and NGL sales were through two operators. Whiting Petroleum Corporation ("Whiting") is the operator of 99% 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

We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our 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.

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

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

The following table shows the activity for the years ended December 31, 2016 and 2015, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2014	$	-
Liabilities acquired on December 18, 2015 (acquisition)		105,000
Accretion (December 18, 2015 to December 31, 2015)		459
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

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

We follow 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 we have taken less than our 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, 2016 and 2015, 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 crude 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 crude 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 crude oil, natural gas and NGL as estimated by management are used. Crude 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 crude oil, natural gas and NGL pricing assumptions are used by management to prepare estimates of crude 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.

Loss Per Common Unit

Basic net loss per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted net loss per 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, 2016 and 2015. As a result, basic and diluted outstanding common units were the same. The Class B Units and Incentive Distribution Rights are not included in loss per common unit until such time that it is probable Payout (as discussed in Note 7) would occur.

Recent 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 plans to adopt the standard effective January 1, 2017. Prior to the adoption of this standard, the Partnership's acquisitions of oil and gas properties were accounted for as existing businesses, and therefore all transaction costs associated with the acquisitions, including title, legal, accounting, brokerage commissions and other related costs were expensed as incurred. The adoption of this standard will not affect transactions that occurred prior to the effective date; however, 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.

In November and August 2016, the FASB issued ASU 2016-18 and ASU 2016-15. Each update addresses and clarifies specific statement of cash flow (Topic 230) issues with the objective to reduce existing diversity in practice. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted. This standard is not expected to have a material impact on the Partnership's consolidated statements of cash flows.

Throughout 2016, the FASB has issued several updates to clarify specific topics originally described in ASU 2014-09, Revenue from Contracts with Customers (Topic 606). These updates include ASU 2016-08, ASU 2016-10, ASU 2016-12 and ASU 2016-20. ASU 2014-09, released in May 2014, 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 was to be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. However, the FASB deferred the effective date by one year in August 2015 in ASU 2015-14. The Partnership currently does not believe this standard will have a material effect on the timing of its revenue recognition, its financial position or its results from operations. However, the Partnership will continue to evaluate the impact, if any, of ASU 2014-09 as well as the related subsequent pronouncements released.

In March 2016, the FASB issued ASU 2016-09, Compensation – Stock Compensation (Topic 718), which simplifies several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public entities, the guidance is effective for reporting periods beginning after December 15, 2016, and it is not expected to have a material impact on the Partnership's 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 and making targeted changes to lessor accounting. The standard is effective for annual periods beginning after December 15, 2018, and interim periods within those years, with early adoption permitted. The standard requires a modified retrospective transition approach for all leases existing at, or entered into after, the date of initial application, with an option to use certain transition relief. The Partnership is currently evaluating the impact of adopting the new standard on its consolidated financial statements.

Oil and Gas Investments	12 Months Ended Dec. 31, 2016
Oil and Gas Property [Abstract]	
Oil and Gas Properties [Text Block]	See below

Note 3. Oil and Gas Investments

As of December 31, 2016, the Partnership owns an approximate 11% non-operated working interest in approximately 216 existing producing wells and approximately 257 future development locations in the Sanish field located in Mountrail County, North Dakota (the "Sanish Field Assets"). The Partnership acquired its interest in the Sanish Field Assets on December 18, 2015 for approximately $159.1 million, subject to post-closing adjustments. During the first half of 2016, the Partnership and the sellers ("Sellers") adjusted the purchase price for the settlement of operating activity that occurred prior to the closing date. The net impact of the purchase price adjustment was an increase to the purchase price of the asset of approximately $0.5 million. The Partnership has expensed, as incurred, transaction costs associated with the acquisition of the Sanish Field Assets. These costs included but were not limited to due diligence, reserve reports, legal and engineering services and site visits. The Partnership incurred transaction costs of $78,000 and $0.3 million in the years

ended December 31, 2016 and 2015. The transaction costs incurred in 2016 primarily relate to the due diligence for the 2017 acquisition of additional interests in the same Sanish Field Assets discussed below.

The Partnership is a non-operator of the Sanish Field Assets. Whiting, one of the largest producers in this basin, is the operator.

The following unaudited pro forma financial information for the period ended December 31, 2015, has been prepared as if the acquisition of the Sanish Field Assets had occurred on January 1, 2015. The unaudited pro forma financial information was derived from the historical Statement 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 acquisition of the Sanish Field Assets and related financing occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

	Year Ended December 31, 2015 (Unaudited)
Revenues	$ 26,831,257
Net loss	$ (2,618,884)

On January 11, 2017, the Partnership completed the purchase of an additional 11% working interest in the Sanish Field Assets. The purchase price was $130.0 million and was funded by the Partnership with $90.0 million in cash (from the sale of the Partnership's common units in its ongoing, best-efforts offering) and a $40.0 million promissory note ("Seller Note"). The Partnership paid the $40.0 million Seller Note in full on February 23, 2017. The Seller Note bore interest at 5% per annum up to the payoff date.

Note Payable	12 Months Ended Dec. 31, 2016
Debt Disclosure [Abstract]	
Debt Disclosure [Text Block]	See below

Note 4. Note Payable

As part of the financing for the purchase of the Sanish Field Assets, on December 18, 2015, the Partnership executed a note in favor of the Sellers ("Seller Note") of the assets in the original principal amount of $97.5 million. On September 29, 2016, the Partnership paid the Seller Note in full.

On June 23, 2016, the Seller Note 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 Sellers $5.0 million at the time of election or by increasing the amount of the Seller Note by $5.0 million. On June 23, 2016, the Partnership exercised that right by increasing the amount of the Partnership's note with the Sellers 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.

In accordance with the Seller Note, 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.

As of December 31 2015, the outstanding balance on the note was $85.0 million and the carrying value of the note, which approximates its fair market value, was $81.7 million. 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.

Fair Value of Financial Instruments	12 Months Ended
	Dec. 31, 2016
Fair Value Disclosures [Abstract]	
Fair Value Disclosures [Text Block]	**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, 2016 and 2015, there were no transfers in or out of Level 1, Level 2, or Level 3 Assets and liabilities measured on a recurring basis.

The Partnership’s financial instruments exposed to concentrations of credit risk primarily consist of cash and cash equivalents and accounts receivable. The carrying values for 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 and current market conditions. See “Note 4. Note Payable” for the fair value discussion on the debt.

Items required to be measured at fair value on a recurring basis by the Partnership include the contingent consideration included in the Partnership’s consideration for the 2015 Sanish Field Asset purchase. Within the valuation hierarchy, the Partnership measured the fair value of the contingent consideration using Level 3 inputs. As of December 31, 2015, the fair value of the contingent consideration was $4,743,752. The inputs for this instrument were significant and unobservable and therefore classified as Level 3 inputs. Management calculated the fair value of the contingent consideration (absent the $5.0 million option) as of December 18, 2015, the Sanish Field Assets acquisition close date, to be $12.5 million. As this was substantially greater than the $5.0 million option, the Partnership believed a market participant would likely view the $5.0 million option as highly probable of being exercised and, therefore, valued the contingent consideration at $5.0 million, discounted to the expected exercise date. The calculation of this liability was based upon a $5.0 million payment to be made to Kaiser-Whiting between June 15, 2016 and June 30, 2016 and a discount rate that was reflective of the Partnership’s market adjusted borrowing rate, as of December 18, 2015, of 11.15%. As discussed in “Note 4. Note Payable”, the Partnership satisfied the contingent payment by increasing its Seller Note on June 23, 2016 by $5.0 million; therefore, the contingent consideration has no value as of December 31, 2016.

Management Agreement	12 Months Ended
	Dec. 31, 2016
Contractors [Abstract]	

Long-term Contracts or Programs Disclosure [Text Block]	**Note 6. Management Agreement** At the initial closing of the sale of its common units on August 19, 2015, the Partnership entered into a Management Services Agreement (the “Management Agreement”) with E11 Management, LLC, (the “Former Manager”), and E11 Incentive Holdings, LLC, an affiliate of the Former Manager (“Incentive Holdings”), whereby the Former Manager agreed to provide management and operating services regarding substantially all aspects of the Partnership’s business. The Former Manager was formed by Aubrey K. McClendon and he served as its Chief Executive Officer. Under the Management Agreement, the Former Manager agreed to provide management and other services to the Partnership including, but not limited to, the following: • Identifying and evaluating oil and natural gas properties for acquisition, development, integration, sale or monetization; • Conducting (or overseeing one of its affiliated companies or third-parties to conduct) drilling, completion, production, marketing and hedging operations as the operator of the Partnership’s oil and natural gas properties; • Overseeing the drilling, completion, production, marketing and hedging operations of our oil and natural gas properties operated by other persons or entities; • Identifying and evaluating financing alternatives for acquisitions of producing oil and natural gas properties; and • Managing the financial, accounting and other back office support functions associated with the drilling, completion, production, marketing and hedging of the Partnership’s oil and natural gas properties. Pursuant to the Management Agreement, the Partnership agreed to pay the Former Manager a monthly fee. Upon entering into the Management Agreement, the Partnership issued 100,000 Class B units to Incentive Holdings. The Class B units entitle the holder to receive a portion of distributions made after Payout, as defined in Note 7 below. The Management Agreement was terminable by the Partnership if, among other reasons, Mr. McClendon, the Former Manager’s key employee, ceased to be employed by the Former Manager and the Partnership did not approve of a proposed replacement of such key employee. On March 2, 2016, Mr. McClendon died in a car accident. Following Mr. McClendon’s death and subsequent correspondence between the Former Manager and the Partnership, on April 5, 2016, the Partnership elected not to approve a replacement key employee for Mr. McClendon and exercised its right to terminate the Management Agreement. Accordingly, the fees under the Management Agreement were no longer accrued as of the effective date of termination. Also, upon termination of the Management Agreement and in accordance with the terms therewith, 37.5% of the Class B units owned by Incentive Holdings were canceled. As of December 31, 2016, the Class B units owned by Incentive Holdings totaled 62,500. Substantially all of the Partnership’s properties are currently being operated by Whiting, an independent third party. Since the Partnership only owns a non-operating interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting, as operator of those properties. Consequently, the termination of the Management Agreement has not had and the Partnership does not anticipate that the termination will have an adverse effect on its operations. For the years ended December 31, 2016 and 2015, the Partnership incurred fees and reimbursable costs of approximately \$0.9 million and \$0.5 million, respectively, under the Management Agreement.

Capital Contribution and Partners' Equity	12 Months Ended
	Dec. 31, 2016
Partners' Capital Notes [Abstract]	
Partners' Capital Notes Disclosure [Text Block]	**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 has been and will be reimbursed for its documented third party out-of-pocket expenses incurred in organizing the Partnership and offering the common units. As of August 19, 2015, the Partnership completed its minimum offering of 1,315,790 common units at \$19.00 per common unit. In March 2016, the Partnership completed the sale of 5,263,158 common units at \$19.00 per common unit. All subsequent shares of common units are being sold at \$20.00 per common unit. As of December 31, 2016 and 2015, the Partnership had completed the sale of 14.6 million and 4.5 million common units for total gross proceeds of \$286.4 million and \$85.2 million, respectively, and proceeds net of offering costs including selling commissions and marketing expenses of \$267.1 million and \$78.3 million, respectively.

The Partnership intends to continue to raise capital through its best-efforts offering by the Dealer Manager at $20.00 per common unit. The Partnership has extended its offering through April 24, 2017; however, the offering will be terminated if all of the common units are sold before then. Under the agreement with the Dealer Manager, the Dealer Manager receives 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, 2016, the total contingent fee is approximately $11.5 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; (iii) to the Dealer Manager, as the contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any, 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 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; (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest.

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 in Note 6.

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, 2016, the Partnership paid distributions of $1.400000 per common unit, or $10.4 million. For the year ended December 31, 2015, the Partnership paid distributions of $0.510138 per common unit, or $1.3 million.

Related Parties	12 Months Ended Dec. 31, 2016
Related Party Transactions [Abstract]	
Related Party Transactions Disclosure [Text Block]	**Note 8. Related Parties**

Note 8. 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 General Partner. For the years ended December 31, 2016 and 2015, the Partnership paid Mr. Merritt $338,396 and $222,099, respectively.

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 will make twelve monthly payments of $8,537. For the year ended December 31, 2016, the Partnership paid $51,222 to the affiliate of the General Partner.

For the years ended December 31, 2016 and 2015, approximately $285,000 and $62,000 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, 2016, approximately $98,000 was due to a member of the General Partner.

During the year ended December 31, 2015 (subsequent to the completion of the minimum offering), the Partnership reimbursed two members of the General Partner approximately $1.8 million in total for offering related costs that had been paid by the members of the General Partner.

Glade M. Knight, Chief Executive Officer of our general partner, and David S. McKenney, Chief Financial Officer of our general partner, are the CEO and CFO of Sundance Energy, L.P., a newly-formed partnership with the primary investment objective to acquire non-operated working interests in oil and gas properties.

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)	12 Months Ended Dec. 31, 2016
Oil and Gas Exploration and Production Industries Disclosures [Abstract]	
Oil and Gas Exploration and Production Industries Disclosures [Text Block]	see below

Note 9. 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, 2016 and 2015 is as follows:

	2016	2015
Producing properties	$ 94,199,024	$ 90,167,047
Non-producing	67,264,748	69,119,768
	161,463,772	159,286,815
Accumulated depreciation, depletion and amortization	(9,908,800)	(391,624)
Net capitalized costs	$ 151,554,972	$ 158,895,191

Costs Incurred

For the years ended December 31, 2016 and 2015, the Partnership incurred the following costs in oil and natural gas producing activities:

	2016	2015
Property acquisition costs	$ 524,175	$ 159,216,768
Development costs	1,652,782	70,047
	$ 2,176,957	$ 159,286,815

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, 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, 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)**
January 1, 2015	-	-	-	-
Acquisition	9,089,252	7,705,802	1,866,775	12,240,327
Extensions, discoveries and other additions	-	-	-	-
Production (December 18 - December 31)	(21,937)	(18,392)	(2,841)	(27,843)
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	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

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, 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 oil, natural gas and NGL prices used in computing the Partnership's reserves as of December 31, 2015 were $50.28 per barrel of oil, $2.59 per Mcf of natural gas, and $15.74 per barrel of NGL, 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, 2015 were $41.74 per barrel of oil, $1.46 per Mcf of natural gas and $9.77 per barrel of NGL.

	Oil (Bbls)	**Natural Gas (Mcf)**	**NGLs (Bbls)**	**Total (BOE)**
Proved developed reserves:				
December 31, 2015	5,602,387	3,964,052	961,147	7,224,210
December 31, 2016	4,748,350	5,163,240	631,080	6,239,970
Proved undeveloped reserves:				
December 31, 2015	3,464,928	3,723,358	902,787	4,988,274
December 31, 2016	4,042,360	4,804,080	587,150	5,430,190

The following details the changes in proved undeveloped reserves for 2015 and 2016:

	BOE
Proved undeveloped reserves, beginning	-
Acquisition	4,988,274
Proved undeveloped reserves, December 31, 2015	4,988,274
Revisions of previous estimates	441,916
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430,190

Although the Partnership has performed limited drilling since acquisition, we anticipate that all the Partnership's current PUD locations will be drilled and converted to PDP within five years of the date they were added. However, 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, and in the event that it subsequently appears that any such undrilled PUD locations would not be drilled by the end of such five-year period, then the Partnership would remove the reserves associated with those locations from the its proved reserves as revisions.

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.

	2016	2015
Future cash inflows	$ 320,606,188	$ 407,928,626
Future production costs	(122,527,901)	(136,547,001)
Future development costs	(43,050,408)	(37,640,024)
Future net cash flows	155,027,879	233,741,601
10% annual discount	(94,081,952)	(134,551,759)
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

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

	2016	2015
Standardized measure at beginning of period	$ 99,189,842	$ -
Changes resulting from:		
Acquisition of reserves	524,175	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(14,693,814)	(480,274)
Net changes in prices and production costs	(28,508,492)	-
Development costs incurred during the period	1,652,782	-
Revisions to previous estimates	8,191,818	-
Change in estimated future development costs	(5,410,384)	-
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

Quarterly Financial Data (Unaudited)	12 Months Ended
	Dec. 31, 2016
Quarterly Financial Information Disclosure [Abstract]	
Quarterly Financial Information [Text	**Note 10. Quarterly Financial Data (Unaudited)**

Block]

The following is a summary of quarterly results of operations for the years ended December 31, 2016 and 2015. 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.

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

2015 (1)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ -	$ -	$ -	$ 703,806
Net loss	$ (55,135)	$ (104,216)	$ (465,643)	$ (937,822)
Basic and diluted net loss per common share	$ -	$ -	$ (0.62)	$ (0.32)

(1) The Partnership did not acquire its first operating asset until December 18, 2015.

Subsequent Events	12 Months Ended Dec. 31, 2016
Subsequent Events [Abstract]	
Subsequent Events [Text Block]	**Note 11. Subsequent Events** On January 11, 2017, the Partnership closed on the purchase of all of the issued and outstanding limited liability company interests of Kaiser-Whiting, LLC, which represents an additional approximate 11% non-operated working interest in the Sanish Field Assets. The purchase price of $130.0 million, subject to customary adjustments, consisted of cash payments totaling $90.0 million and the delivery of a promissory note in favor of the seller of $40.0 million. The Partnership paid the $40.0 million promissory note in full on February 23, 2017. With the closing of the purchase, the Partnership now owns an approximate 22-23% non-operated working interest in the Sanish Field Assets. See Note 3. Oil and Gas Investments for more information. In January 2017, the Partnership declared and paid $1.6 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units. In January 2017, the Partnership closed on the issuance of approximately 1.1 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $21.7 million and proceeds net of selling and marketing costs of approximately $20.4 million. In February 2017, the Partnership declared and paid $1.7 million, or $0.107397 per outstanding common unit, in distributions to its holders of common units. In February 2017, the Partnership closed on the issuance of approximately 1.0 million common units through its ongoing best-efforts offering, representing gross proceeds to the Partnership of approximately $20.4 million and proceeds net of selling and marketing costs of approximately $19.2 million.

Accounting Policies, by Policy (Policies)	12 Months Ended Dec. 31, 2016
Accounting Policies [Abstract]	
Basis of Accounting, Policy [Policy Text Block]	*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").
Cash and Cash Equivalents, Policy [Policy Text Block]	*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.
Deferred Charges, Policy [Policy Text Block]	*Offering Costs*

	The Partnership is raising capital through an ongoing best-efforts offering of common units by David Lerner Associates, Inc., who receives a selling commission and a marketing expense allowance based on proceeds of the common units sold. Additionally, the Partnership has incurred other offering costs including legal, accounting and reporting services. These offering costs are recorded by the Partnership as a reduction of partners' equity. As of December 31, 2016 and 2015, the Partnership had sold 14.6 million and 4.5 million common units for gross proceeds of $286.4 million and $85.2 million, respectively, and proceeds net of offering costs of $267.1 million and $78.3 million, respectively.
Oil and Gas Properties Policy [Policy Text Block]	*Property and Depreciation, Depletion and Amortization* We account for our 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 or Disposal of Long-Lived Assets, Policy [Policy Text Block]	*Impairment* We assess our 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, we recognize 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.
Concentration Risk, Credit Risk, Policy [Policy Text Block]	*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 we have an interest in may be similarly affected by changes in economic, industry or other conditions. At December 31, 2016, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2016, the Partnership's oil, natural gas and NGL sales were through two operators. Whiting Petroleum Corporation ("Whiting") is the operator of 99% 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 Obligations, Policy [Policy Text Block]	*Asset Retirement Obligation* We have significant obligations to remove tangible equipment and facilities and restore land at the end of oil and natural gas production operations. Our 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. We record an asset retirement obligation ("ARO") and capitalize the asset retirement cost in oil and natural gas properties in the period in which the

retirement obligation is incurred based upon the fair value of an obligation to perform site reclamation, dismantle facilities or plug and abandon wells. After recording these amounts, the ARO is accreted to its future estimated value using an assumed cost of funds and the additional capitalized costs are depreciated on a unit-of-production basis.

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

The following table shows the activity for the years ended December 31, 2016 and 2015, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2014	$ -
Liabilities acquired on December 18, 2015 (acquisition)	105,000
Accretion (December 18, 2015 to December 31, 2015)	459
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

Income Tax, Policy [Policy Text Block]

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.

Industry Specific Policies, Oil and Gas [Policy Text Block]

Oil, NGL and Natural Gas Sales and Natural Gas Imbalances

We follow 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 we have taken less than our share of production.

Environmental Costs, Policy [Policy Text Block]

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, 2016 and 2015, there were no such costs accrued.

Use of Estimates, Policy [Policy Text Block]

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 crude 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 crude 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 crude oil, natural gas and NGL as estimated by management are used. Crude 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 crude oil, natural gas and NGL pricing assumptions are used by management to prepare estimates of

	crude 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, Policy [Policy Text Block]	*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.
Earnings Per Share, Policy [Policy Text Block]	*Loss Per Common Unit* Basic net loss per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted net loss per 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, 2016 and 2015. As a result, basic and diluted outstanding common units were the same. The Class B Units and Incentive Distribution Rights are not included in loss per common unit until such time that it is probable Payout (as discussed in Note 7) would occur.
New Accounting Pronouncements, Policy [Policy Text Block]	*Recent 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 plans to adopt the standard effective January 1, 2017. Prior to the adoption of this standard, the Partnership's acquisitions of oil and gas properties were accounted for as existing businesses, and therefore all transaction costs associated with the acquisitions, including title, legal, accounting, brokerage commissions and other related costs were expensed as incurred. The adoption of this standard will not affect transactions that occurred prior to the effective date; however, 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. In November and August 2016, the FASB issued ASU 2016-18 and ASU 2016-15. Each update addresses and clarifies specific statement of cash flow (Topic 230) issues with the objective to reduce existing diversity in practice. For public entities, the guidance is effective for reporting periods beginning after December 15, 2017, and interim periods within those fiscal years. Early adoption is permitted. This standard is not expected to have a material impact on the Partnership's consolidated statements of cash flows. Throughout 2016, the FASB has issued several updates to clarify specific topics originally described in ASU 2014-09, Revenue from Contracts with Customers (Topic 606). These updates include ASU 2016-08, ASU 2016-10, ASU 2016-12 and ASU 2016-20. ASU 2014-09, released in May 2014, 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 was to be effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. However, the FASB deferred the effective date by one year in August 2015 in ASU 2015-14. The Partnership currently does not believe this standard will have a material effect on the timing of its revenue recognition, its financial position or its results from operations. However, the Partnership will continue to evaluate the impact, if any, of ASU 2014-09 as well as the related subsequent pronouncements released. In March 2016, the FASB issued ASU 2016-09, Compensation – Stock Compensation (Topic 718), which simplifies several aspects of accounting for share-based payment transactions, including income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. For public entities, the guidance is effective for reporting periods beginning after December 15, 2016, and it is not expected to have a material impact on the Partnership's 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 and making targeted changes to lessor accounting. The standard is effective for annual periods beginning after December 15, 2018, and interim periods within those years, with early adoption permitted. The standard requires a modified retrospective transition approach for all leases existing at, or entered into after, the date of initial application, with an option to use certain transition relief. The Partnership is currently evaluating the impact of adopting the new standard on its consolidated financial statements.

Summary of Significant Accounting Policies (Tables)	12 Months Ended Dec. 31, 2016
Accounting Policies [Abstract]	
Schedule of Asset Retirement Obligations [Table Text Block]	The following table shows the activity for the years ended December 31, 2016 and 2015, relating to the Partnership's asset retirement obligations:

Balance as of December 31, 2014	$	-
Liabilities acquired on December 18, 2015 (acquisition)		105,000
Accretion (December 18, 2015 to December 31, 2015)		459
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

Oil and Gas Investments (Tables)	12 Months Ended Dec. 31, 2016
Oil and Gas Property [Abstract]	
Business Acquisition, Pro Forma Information [Table Text Block]	The following unaudited pro forma financial information for the period ended December 31, 2015, has been prepared as if the acquisition of the Sanish Field Assets had occurred on January 1, 2015. The unaudited pro forma financial information was derived from the historical Statement 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 acquisition of the Sanish Field Assets and related financing occurred on the basis assumed above, nor is such information indicative of the Partnership's expected future results of operations.

		Year Ended December 31, 2015
		(Unaudited)
Revenues	$	26,831,257
Net loss	$	(2,618,884)

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Tables)	12 Months Ended Dec. 31, 2016
Oil and Gas Exploration and Production Industries Disclosures [Abstract]	
Capitalized Costs Relating to Oil and Gas Producing Activities Disclosure [Table Text Block]	The aggregate amount of capitalized costs of oil, natural gas and NGL properties and related accumulated depreciation, depletion and amortization as of December 31, 2016 and 2015 is as follows:

		2016		2015
Producing properties	$	94,199,024	$	90,167,047
Non-producing		67,264,748		69,119,768
		161,463,772		159,286,815
Accumulated depreciation, depletion and amortization		(9,908,800)		(391,624)
Net capitalized costs	$	151,554,972	$	158,895,191

Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure [Table Text Block]	For the years ended December 31, 2016 and 2015, the Partnership incurred the following costs in oil and natural gas producing activities:

		2016		2015
Property acquisition costs	$	524,175	$	159,216,768
Development costs		1,652,782		70,047
	$	2,176,957	$	159,286,815

Schedule of Proved Developed and Undeveloped Oil and Gas Reserve Quantities [Table Text Block]	Net quantities of proved, developed and undeveloped oil, natural gas and NGL reserves are summarized as follows:

	Proved Reserves		
	Oil	Natural Gas	NGLs

	(Bbls)	(Mcf)	(Bbls)	Total (BOE)
January 1, 2015	-	-	-	-
Acquisition	9,089,252	7,705,802	1,866,775	12,240,327
Extensions, discoveries and other additions	-	-	-	-
Production (December 18 - December 31)	(21,937)	(18,392)	(2,841)	(27,843)
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	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

	Oil (Bbls)	Natural Gas (Mcf)	NGLs (Bbls)	Total (BOE)
Proved developed reserves:				
December 31, 2015	5,602,387	3,964,052	961,147	7,224,210
December 31, 2016	4,748,350	5,163,240	631,080	6,239,970
Proved undeveloped reserves:				
December 31, 2015	3,464,928	3,723,358	902,787	4,988,274
December 31, 2016	4,042,360	4,804,080	587,150	5,430,190

	BOE
Proved undeveloped reserves, beginning	-
Acquisition	4,988,274
Proved undeveloped reserves, December 31, 2015	4,988,274
Revisions of previous estimates	441,916
Conversion to proved developed reserves	-
Proved undeveloped reserves acquired	-
Proved undeveloped reserves, December 31, 2016	5,430,190

Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Table Text Block]

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.

	2016	2015
Future cash inflows	$ 320,606,188	$ 407,928,626
Future production costs	(122,527,901)	(136,547,001)
Future development costs	(43,050,408)	(37,640,024)
Future net cash flows	155,027,879	233,741,601
10% annual discount	(94,081,952)	(134,551,759)
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows [Table Text Block]

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

	2016	2015
Standardized measure at beginning of period	$ 99,189,842	$ -
Changes resulting from:		
Acquisition of reserves	524,175	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(14,693,814)	(480,274)
Net changes in prices and production costs	(28,508,492)	-
Development costs incurred during the period	1,652,782	-
Revisions to previous estimates	8,191,818	-
Change in estimated future development costs	(5,410,384)	-
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

Quarterly Financial Data (Unaudited) (Tables)	12 Months Ended
	Dec. 31, 2016

Quarterly Financial Information Disclosure [Abstract]	
Quarterly Financial Information [Table Text Block]	The following is a summary of quarterly results of operations for the years ended December 31, 2016 and 2015. 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.

	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

	2015 (1)			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Total revenue	$ -	$ -	$ -	$ 703,806
Net loss	$ (55,135)	$ (104,216)	$ (465,643)	$ (937,822)
Basic and diluted net loss per common share	$ -	$ -	$ (0.62)	$ (0.32)

(1) The Partnership did not acquire its first operating asset until December 18, 2015.

Partnership Organization (Details) - USD ($)		12 Months Ended
	Jul. 09, 2013	Dec. 31, 2015
Partnership Organization (Details) [Line Items]		
Limited Liability Company or Limited Partnership, Business, Formation State	Delaware	
Partners' Capital Account, Contributions	$ 1,000	
Subsidiary of Limited Liability Company or Limited Partnership, Business Purpose		(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 and will be used to acquire producing and non-producing oil and natural gas properties onshore in the United States and to develop those properties
Best-Efforts Offering [Member]		
Partnership Organization (Details) [Line Items]		
Total amount of Unit offering		$ 2,000,000,000
Total amount of Units offered		100,263,158
Minimum Unit Offering		1,315,790

Summary of Significant Accounting Policies (Details)		12 Months Ended		
	Mar. 04, 2016 shares	Dec. 31, 2016 USD ($) shares	Dec. 31, 2015 USD ($) shares	Dec. 31, 2014 USD ($)
Summary of Significant Accounting Policies (Details) [Line Items]				
Proceeds from Issuance of Common Limited Partners Units		$ 188,820,033	$ 78,286,761	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units		$ 188,825,158	$ 78,308,749	$ 0
Number of Operators		2		
Antidilutive Securities Excluded from Computation of Earnings Per Share, Amount | shares		0	0	
Best-Efforts Offering [Member]				
Summary of Significant Accounting Policies (Details) [Line Items]				
Partners' Capital Account, Units, Sale of Units | shares	5,263,158	14,600,000	4,500,000	

Proceeds from Issuance of Common Limited Partners Units		$ 286,400,000	$ 85,200,000	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units		$ 267,100,000	$ 78,300,000	
Whiting Petroleum [Member] | Sales Revenue, Net [Member] | Customer Concentration Risk [Member]				
Summary of Significant Accounting Policies (Details) [Line Items]				
Concentration Risk, Percentage		99.00%		

Summary of Significant Accounting Policies (Details) - Schedule of Asset Retirement Obligations - USD ($)	**12 Months Ended**	
	Dec. 31, 2016	**Dec. 31, 2015**
Schedule of Asset Retirement Obligations [Abstract]		
Balance	$ 105,459	$ 0
Well additions	1,868	105,000
Accretion	9,689	459
Revisions in estimated cash flows	(46,393)	
Balance	$ 70,623	$ 105,459

Oil and Gas Investments (Details)			**12 Months Ended**		
	Jan. 11, 2017 USD ($)	**Dec. 18, 2015 USD ($)**	**Dec. 31, 2016 USD ($)**	**Dec. 31, 2015 USD ($)**	**Dec. 31, 2014 USD ($)**
Oil and Gas Investments (Details) [Line Items]					
Payments to Acquire Oil and Gas Property			$ 1,000,000	$ 60,000,000	$ 0
Sanish Field Located in Mountrail County, North Dakota [Member]					
Oil and Gas Investments (Details) [Line Items]					
Gas and Oil Area Developed, Net			11.00%		
Productive Oil Wells, Number of Wells, Net			216		
Gas and Oil Area Undeveloped, Net			257		
Business Combination, Consideration Transferred		$ 159,100,000			
Business Combination, Provisional Information, Initial Accounting Incomplete, Adjustment, Consideration Transferred		500,000			
Business Combination, Consideration Transferred, Liabilities Incurred			$ 78,000	$ 300,000	
Sanish Field Located in Mountrail County, North Dakota [Member] | Subsequent Event [Member]					
Oil and Gas Investments (Details) [Line Items]					
Gas and Oil Area Developed, Net	11.00%				
Business Combination, Consideration Transferred	$ 130,000,000				
Oil Wells Purchase Agreement,	The purchase price was $130.0 million and was funded by the Partnership with $90.0 million in cash				

Purchase Price Description	(from the sale of the Partnership's common units in its ongoing, best-efforts offering) and a $40.0 million promissory note ("Seller Note"). The Partnership paid the $40.0 million Seller Note in full on February 23, 2017. The Seller Note bore interest at 5% per annum up to the payoff date.				
Payments to Acquire Oil and Gas Property	$ 90,000,000				
Notes Payable, Other Payables [Member]					
Oil and Gas Investments (Details) [Line Items]					
Debt Instrument, Face Amount		$ 97,500,000			
Notes Payable, Other Payables [Member] | Sanish Field Located in Mountrail County, North Dakota [Member] | Subsequent Event [Member]					
Oil and Gas Investments (Details) [Line Items]					
Debt Instrument, Face Amount	$ 40,000,000				
Debt Instrument, Interest Rate, Stated Percentage	5.00%				

Oil and Gas Investments (Details) - Business Acquisition, Pro Forma Information	12 Months Ended
	Dec. 31, 2015 USD ($)
Business Acquisition, Pro Forma Information [Abstract]	
Revenues	$ 26,831,257
Net loss	$ (2,618,884)

Note Payable (Details) - Notes Payable, Other Payables [Member] - USD ($)	3 Months Ended	12 Months Ended			
	Sep. 30, 2016	Dec. 31, 2016	Jun. 30, 2016	Dec. 31, 2015	Dec. 18, 2015
Note Payable (Details) [Line Items]					
Debt Instrument, Face Amount					$ 97,500,000
Debt Instrument, Increase (Decrease) for Period, Description		On June 23, 2016, the Seller Note 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 Sellers $5.0 million at the time of election or by increasing the amount of the Seller Note by $5.0 million.			
Debt Instrument, Description		On June 23, 2016, the Partnership exercised that right by increasing the amount of the Partnership's note with the Sellers 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.			
Debt Instrument, Increase (Decrease), Net		$ 5,000,000			
Debt Instrument, Fee		In accordance with the Seller Note, 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.			
Amortization of Deferred Loan Origination Fees, Net	$ (250,000)				
Debt Instrument, Fee Amount			$ 250,000		
Debt Instrument, Outstanding Balance				$ 85,000,000	
Notes Payable				$ 81,700,000	

Fair Value of Financial Instruments (Details) - USD ($)	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015

Fair Value of Financial Instruments (Details) [Line Items]		
Fair Value Inputs, Discount Rate	10.00%	10.00%
Sanish Field Located in Mountrail County, North Dakota [Member]		
Fair Value of Financial Instruments (Details) [Line Items]		
Business Combination, Contingent Consideration, Liability	$ 5,000,000	$ 4,743,752
Fair Value Measurements, Valuation Processes, Description		Management calculated the fair value of the contingent consideration (absent the $5.0 million option) as of December 18, 2015, the Sanish Field Assets acquisition close date, to be $12.5 million. As this was substantially greater than the $5.0 million option, the Partnership believed a market participant would likely view the $5.0 million option as highly probable of being exercised and, therefore, valued the contingent consideration at $5.0 million, discounted to the expected exercise date. The calculation of this liability was based upon a $5.0 million payment to be made to Kaiser-Whiting between June 15, 2016 and June 30, 2016 and a discount rate that was reflective of the Partnership's market adjusted borrowing rate, as of December 18, 2015, of 11.15%.
Fair Value Inputs, Discount Rate		11.15%
Sanish Field Located in Mountrail County, North Dakota [Member] | Absent the $5.0 Million Option [Member]		
Fair Value of Financial Instruments (Details) [Line Items]		
Business Combination, Contingent Consideration, Liability		$ 12,500,000

Management Agreement (Details) - USD ($) $ in Millions		12 Months Ended	
	Apr. 05, 2016	Dec. 31, 2016	Dec. 31, 2015
Management Agreement (Details) [Line Items]			
Owned Property, Reimbursable Management Costs		$ 0.9	$ 0.5
E11 Incentive Holdings [Member]			
Management Agreement (Details) [Line Items]			
Class B Units Issued to Manager		100,000	
Management Termination Description		The Management Agreement was terminable by the Partnership if, among other reasons, Mr. McClendon, the Former Manager's key employee, ceased to be employed by the Former Manager and the Partnership did not approve of a proposed replacement of such key employee. On March 2, 2016, Mr. McClendon died in a car accident. Following Mr. McClendon's death and subsequent correspondence between the Former Manager and the Partnership, on April 5, 2016, the Partnership elected not to approve a replacement key employee for Mr. McClendon and exercised its right to terminate the Management Agreement. Accordingly, the fees under the Management Agreement were no longer accrued as of the effective date of termination. Also, upon termination of the Management Agreement and in accordance with the terms therewith, 37.5% of the Class B units owned by Incentive Holdings were canceled. As of December 31, 2016, the Class B units owned by Incentive Holdings totaled 62,500.Substantially all of the Partnership's properties are currently being operated by Whiting, an independent third party. Since the Partnership only owns a non-operating interest in the Sanish Field Assets, most of the services that the Former Manager had been contracted to perform are being performed by Whiting, as operator of those properties. Consequently, the termination of the Management Agreement has not had and the Partnership does not anticipate that the termination will have an adverse effect on its operations.	
Percentage of Manager Shares Canceled upon Termination of Agreement	37.50%		
Capital Units held by Manager affiliate		62,500	

Capital Contribution and Partners' Equity (Details) - USD ($)			1 Months Ended	9 Months Ended	12 Months Ended		
	Mar. 04, 2016	Jul. 09, 2013	Mar. 31, 2016	Dec. 31, 2016	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Capital Contribution and Partners' Equity (Details) [Line Items]							
Partners' Capital Account, Contributions		$ 1,000					

Distributions to organizational limited partner		$ 990				$ (990)	
Proceeds from Issuance of Common Limited Partners Units					$ 188,820,033	$ 78,286,761	
Managing Dealer, Selling Commissions, Percentage					6.00%		
Managing Dealer, Maximum Contingent Incentive Fee on Gross Proceeds, Percentage					4.00%		
Maximum Contingent Offering Costs, Selling Commissions and Marketing Expenses				$ 11,500,000	$ 11,500,000		
Key Provisions of Operating or Partnership Agreement, Description					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; (iii) to the Dealer Manager, as the contingent incentive fee paid under the Dealer Manager Agreement, 30%, and (iv) the remaining amount, if any, 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 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; (iii) the remaining amount to the Record Holders of outstanding common units, pro rata based on their percentage interest.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 in Note 6.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.		
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)					$ 1.400000	$ 0.510138	
Distribution Made to Limited Partner, Cash Distributions Paid					$ 10,448,981	$ 1,271,730	$ 0
Best-Efforts Offering [Member]							
Capital Contribution and Partners' Equity (Details) [Line Items]							
Minimum Unit Offering (in Shares)						1,315,790	
Partners Capital Account, Units Sold, Price Per Unit			$ 19.00	$ 20.00		$ 19.00	
Partners' Capital Account, Units, Sale of Units (in Shares)	5,263,158				14,600,000	4,500,000	
Proceeds from Issuance of Common Limited Partners Units					$ 286,400,000	$ 85,200,000	
Proceeds, Net of Selling Commissions and Marketing Expenses, from Issuance of Common Limited Partners Units					$ 267,100,000	$ 78,300,000	
Partners' Capital Account, Description of Units Sold					The Partnership intends to continue to raise capital through its best-efforts offering by the Dealer Manager at $20.00 per common unit.		

Related Parties (Details) - USD ($)		12 Months Ended	
	Jul. 01, 2016	Dec. 31, 2016	Dec. 31, 2015
Affiliated Entity [Member]			
Related Parties (Details) [Line Items]			
Operating Leases, Rent Expense, Minimum Rentals	$ 8,537		
Operating Leases, Rent Expense		$ 51,222	
General Partner [Member]			
Related Parties (Details) [Line Items]			
Related Party Transaction, Selling, General and Administrative Expenses from Transactions with Related Party		285,000	$ 62,000
Due to Related Parties, Current		98,000	
Consulting Services Provided to General Partner [Member] | President [Member]			
Related Parties (Details) [Line Items]			
Costs and Expenses, Related Party		$ 338,396	222,099
Reimbursement of Offering Related Cost [Member] | President [Member]			
Related Parties (Details) [Line Items]			
General Partner Reimbursement			$ 1,800,000

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details)	12 Months Ended	
	Dec. 31, 2016 $ / bbl $ / Mcf	Dec. 31, 2015 $ / bbl $ / Mcf
Before Price Differentials [Member] | Oil [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices	42.75	50.28
Before Price Differentials [Member] | Natural Gas [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices | $ / Mcf	2.48	2.59
Before Price Differentials [Member] | Natural Gas Liquids [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices		15.74
Including Effect of Price Differential Adjustments [Member] | Oil [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices	36.25	41.74
Including Effect of Price Differential Adjustments [Member] | Natural Gas		

[Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices | $ / Mcf	(0.38)	1.46
Including Effect of Price Differential Adjustments [Member] | Natural Gas Liquids [Member]		
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]		
Average Sales Prices	4.70	9.77

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Capitalized Costs Relating to Oil and Gas Producing Activities Disclosure - USD ($)	Dec. 31, 2016	Dec. 31, 2015
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]		
Proved Properties	$ 161,463,772	$ 159,286,815
Accumulated depreciation, depletion and amortization	(9,908,800)	(391,624)
Net capitalized costs	151,554,972	158,895,191
Producing Properties [Member]		
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]		
Proved Properties	94,199,024	90,167,047
Non-Producing Properties [Member]		
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]		
Proved Properties	$ 67,264,748	$ 69,119,768

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure - USD ($)	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Cost Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities Disclosure [Abstract]		
Property acquisition costs	$ 524,175	$ 159,216,768
Development costs	1,652,782	70,047
	$ 2,176,957	$ 159,286,815

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Schedule of Proved Developed and Undeveloped Oil and Gas Reserve	12 Months Ended	
	Dec. 31, 2016 Boe bbl Mcf	Dec. 31, 2015 Boe bbl Mcf

Quantities		
Reserve Quantities [Line Items]		
Balance	12,212,484	0
Proved developed reserves:		
Balance, Proved Developed Reserves (in Barrels of Oil Equivalent) | Boe	6,239,970	7,224,210
Proved undeveloped reserves:		
Balance, Proved Undeveloped Reserves (in Barrels of Oil Equivalent) | Boe	5,430,190	4,988,274
Balance, Proved Undeveloped Reserves (in Barrels of Oil Equivalent) | Boe	4,988,274	0
Balance, Proved Undeveloped Reserves (in Barrels of Oil Equivalent) | Boe	5,430,190	4,988,274
Acquisition	0	12,240,327
Extensions, discoveries and other additions	0	0
Revisions of previous estimates	112,182	
Production	(654,506)	(27,843)
Revisions of previous estimates (in Barrels of Oil Equivalent) | Boe	441,916	
Conversion to proved developed reserves (in Barrels of Oil Equivalent) | Boe	0	
Acquisition (in Barrels of Oil Equivalent) | Boe	0	4,988,274
Balance	11,670,160	12,212,484
Oil [Member]		
Reserve Quantities [Line Items]		
Balance	9,067,315	0
Proved developed reserves:		
Balance, Proved Developed Reserves	4,748,350	5,602,387
Proved undeveloped reserves:		
Balance, Proved Undeveloped Reserves	4,042,360	3,464,928
Acquisition	0	9,089,252
Extensions, discoveries and other additions	0	0
Revisions of previous estimates	222,321	
Production	(498,926)	(21,937)
Balance	8,790,710	9,067,315
Natural Gas [Member]		
Reserve Quantities [Line Items]		
Balance | Mcf	7,687,410	0
Proved developed reserves:		
Balance, Proved Developed Reserves | Mcf	5,163,240	3,964,052
Proved undeveloped reserves:		
Balance, Proved Undeveloped Reserves | Mcf	4,804,080	3,723,358
Acquisition | Mcf	0	7,705,802
Extensions, discoveries and other additions | Mcf	0	0
Revisions of previous estimates | Mcf	2,799,032	
Production | Mcf	(519,122)	(18,392)
Balance | Mcf	9,967,320	7,687,410
Natural Gas Liquids [Member]		
Reserve Quantities [Line Items]		

Balance	1,863,934	0
Proved developed reserves:		
Balance, Proved Developed Reserves	631,080	961,147
Proved undeveloped reserves:		
Balance, Proved Undeveloped Reserves	587,150	902,787
Acquisition	0	1,866,775
Extensions, discoveries and other additions	0	0
Revisions of previous estimates	(576,645)	
Production	(69,059)	(2,841)
Balance	1,218,230	1,863,934

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure - USD ($)	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]			
Future cash inflows	$ 320,606,188	$ 407,928,626	
Future production costs	(122,527,901)	(136,547,001)	
Future development costs	(43,050,408)	(37,640,024)	
Future net cash flows	155,027,879	233,741,601	
10% annual discount	(94,081,952)	(134,551,759)	
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842	$ 0

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure (Parentheticals)	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Standardized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]		
Annual discount	10.00%	10.00%

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows - USD ($)	12 Months Ended	
	Dec. 31, 2016	Dec. 31, 2015
Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows [Abstract]		
Standardized measure at beginning of period	$ 99,189,842	$ 0
Changes resulting from:		
Acquisition of reserves	524,175	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(14,693,814)	(480,274)
Net changes in prices and production costs	(28,508,492)	0
Development costs incurred during the		

period	1,652,782	0
Revisions to previous estimates	8,191,818	0
Change in estimated future development costs	(5,410,384)	0
Standardized measure of discounted future net cash flows	$ 60,945,927	$ 99,189,842

Quarterly Financial Data (Unaudited) (Details) - Quarterly Financial Information - USD ($)	3 Months Ended								12 Months Ended		
	Dec. 31, 2016	Sep. 30, 2016	Jun. 30, 2016	Mar. 31, 2016	Dec. 31, 2015 [1]	Sep. 30, 2015 [1]	Jun. 30, 2015 [1]	Mar. 31, 2015 [1]	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014
Quarterly Financial Information [Abstract]											
Total revenue	$ 5,080,081	$ 5,434,047	$ 5,532,113	$ 4,319,097	$ 703,806	$ 0	$ 0	$ 0	$ 20,365,338	$ 703,806	$ 0
Net income (loss)	$ 732,421	$ (1,511,146)	$ (859,383)	$ (3,592,456)	$ (937,822)	$ (465,643)	$ (104,216)	$ (55,135)	$ (5,230,564)	$ (1,562,816)	$ (163,595)
Basic and diluted net income (loss) per common share (in Dollars per share)	$ 0.06	$ (0.20)	$ (0.14)	$ (0.73)	$ (0.32)	$ (0.62)	$ 0	$ 0	$ (0.69)	$ (1.70)	$ 0

[1] The Partnership did not acquire its first operating asset until December 18, 2015.

Subsequent Events (Details) - USD ($)				1 Months Ended		12 Months Ended			
	Feb. 23, 2017	Jan. 11, 2017	Mar. 04, 2016	Feb. 23, 2017	Jan. 31, 2017	Dec. 31, 2016	Dec. 31, 2015	Dec. 31, 2014	Dec. 18, 2015
Subsequent Events (Details) [Line Items]									
Payments to Acquire Oil and Gas Property						$ 1,000,000	$ 60,000,000	$ 0	
Distribution Made to Limited Partner, Cash Distributions Paid						$ 10,448,981	$ 1,271,730	0	
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)						$ 1.400000	$ 0.510138		
Proceeds from Issuance of Common Limited Partners Units						$ 188,820,033	$ 78,286,761		
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units						$ 188,825,158	$ 78,308,749	$ 0	
Best-Efforts Offering [Member]									
Subsequent Events (Details) [Line Items]									
Partners' Capital Account, Units, Sale of Units (in Shares)			5,263,158			14,600,000	4,500,000		
Proceeds from Issuance of Common Limited Partners Units						$ 286,400,000	$ 85,200,000		
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units						$ 267,100,000	$ 78,300,000		
Subsequent Event [Member]									
Subsequent Events (Details) [Line Items]									
Distribution Made to Limited Partner, Cash Distributions Paid				$ 1,700,000	$ 1,600,000				
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)				$ 0.107397	$ 0.107397				
Subsequent Event [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]									
Subsequent Events (Details) [Line									

Items]									
Gas and Oil Area Developed, Net		11.00%							
Business Combination, Consideration Transferred		$ 130,000,000							
Payments to Acquire Oil and Gas Property		$ 90,000,000							
Subsequent Event [Member] | Best-Efforts Offering [Member]									
Subsequent Events (Details) [Line Items]									
Partners' Capital Account, Units, Sale of Units (in Shares)				1,000,000	1,100,000				
Proceeds from Issuance of Common Limited Partners Units				$ 20,400,000	$ 21,700,000				
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units				$ 19,200,000	$ 20,400,000				
Minimum [Member] | Subsequent Event [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]									
Subsequent Events (Details) [Line Items]									
Gas and Oil Area Developed, Net		22.00%							
Maximum [Member] | Subsequent Event [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]									
Subsequent Events (Details) [Line Items]									
Gas and Oil Area Developed, Net		23.00%							
Notes Payable, Other Payables [Member]									
Subsequent Events (Details) [Line Items]									
Debt Instrument, Face Amount									$ 97,500,000
Notes Payable, Other Payables [Member] | Subsequent Event [Member] | Sanish Field Located in Mountrail County, North Dakota [Member]									
Subsequent Events (Details) [Line Items]									
Debt Instrument, Face Amount		$ 40,000,000							
Repayments of Notes Payable	$ 40,000,000								