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

Document And Entity Information - USD ($)	12 Months Ended		
	Dec. 31, 2015	Mar. 28, 2016	Jun. 30, 2015
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		5,586,294	
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, 2015		
Document Fiscal Year Focus	2015		
Document Fiscal Period Focus	FY		

Consolidated Balance Sheets - USD ($)	Dec. 31, 2015	Dec. 31, 2014
Assets		
Cash	$ 3,287,054	$ 94
Accounts Receivable:		
Oil, natural gas and natural gas liquids revenues	1,417,751	0
Acquisition post-closing receivable	1,556,530	0
Deferred offering costs and other assets	0	1,449,930
Total Current Assets	6,261,335	1,450,024
Oil and natural gas properties, successful efforts method, net of accumulated depreciation, depletion and amortization; December 31, 2015, $391,624; December 31, 2014, $0	158,895,191	0
Total Assets	165,156,526	1,450,024
Liabilities and Partners' Equity (Deficit)		
Note payable	81,684,758	0
Due to general partner member	0	1,232,675
Contingent Consideration	4,743,752	0
Accounts payable and accrued expenses	3,449,442	390,000
Total Current Liabilities	89,877,952	1,622,675
Limited partners' interest (4,486,625 common units and 0 units issued and outstanding at December 31, 2015 and December 31, 2014, respectively)	75,280,301	(170,924)
General partner's interest	(1,727)	(1,727)
Class B Units (100,000 units and 0 units issued and outstanding at December 31, 2015 and December 31, 2014, respectively)	0	0
Total Partners' Equity (Deficit)	75,278,574	(172,651)
Total Liabilities and Partners' Equity	$ 165,156,526	$ 1,450,024

(Deficit)

Consolidated Balance Sheets (Parentheticals) - USD ($)	Dec. 31, 2015	Dec. 31, 2014
Oil and natural gas properties, accumulated depreciation, depletion and amortization (in Dollars)	$ 391,624	$ 0
Limited partners' interest, common units issued	4,486,625	0
Limited partners' interest, common units outstanding	4,486,625	0
Class B Units, units issued	100,000	0
Class B Units, units outstanding	100,000	0

Consolidated Statements of Operations - USD ($)	6 Months Ended	12 Months Ended	
	Dec. 31, 2013	Dec. 31, 2015	Dec. 31, 2014
Revenue			
Oil, natural gas and natural gas liquids revenues	$ 0	$ 703,806	$ 0
Expenses			
Lease operating expenses	0	149,072	0
Gathering and processing expenses	0	18,139	0
Production taxes	0	74,460	0
Management fees	0	252,524	0
Acquisition related costs	0	313,366	0
General and administrative expenses	10,056	745,884	163,595
Depreciation, depletion and amortization	0	392,084	0
Total expenses	10,056	1,945,529	163,595
Operating loss	(10,056)	(1,241,723)	(163,595)
Interest expense, net	0	321,093	0
Net loss	$ (10,056)	$ (1,562,816)	$ (163,595)
Basic and diluted net loss per common unit (in Dollars per share)	$ 0	$ (1.70)	$ 0
Weighted average common units outstanding - basic and diluted (in Shares)	0	920,668	0

Consolidated Statements of Partners' Equity - USD ($)	Total	Limited Partner [Member]	General Partner [Member]	Capital Unit, Class B [Member]
Balance at Jul. 08, 2013	$ 1,000	$ 990	$ 10	$ 0
Net loss	(10,056)	(9,955)	(101)	
Balance at Dec. 31, 2013	(9,056)	(8,965)	(91)	0
Distributions declared and to common units paid ($0.510138 per unit)	0			
Net loss	(163,595)	(161,959)	(1,636)	
Balance at Dec. 31, 2014	(172,651)	(170,924)	(1,727)	0
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 ($0.510138 per unit)	(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

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

Consolidated Statements of Cash Flows - USD ($)	6 Months Ended	12 Months Ended	
	Dec. 31, 2013	Dec. 31, 2015	Dec. 31, 2014
Cash flow from operating activities:			
Net loss	$ (10,056)	$ (1,562,816)	$ (163,595)
Adjustments to reconcile net loss to cash used in operating activities:			
Depreciation, depletion and amortization	0	392,084	0

Non-cash fair value adjusted amortization	0	175,424	0
Changes in operating assets and liabilities:			
Increase in accounts receivable oil, natural gas and natural gas liquids	0	(703,806)	0
Accounts payable and accrued expenses	0	653,106	0
Due to general partner member	10,046	(158,641)	163,595
Net cash flow used in operating activities	(10)	(1,204,649)	0
Cash flow from investing activities			
Cash paid for acquisition of oil, natural gas and natural gas liquids properties	0	(60,000,000)	0
Net cash flow used in investing activities	0	(60,000,000)	0
Cash flow from financing activities			
Cash paid for offering costs	(896)	0	0
Net proceeds related to issuance of units	0	78,308,749	0
Distributions paid to limited partners	0	(1,271,730)	0
Payments on debt	0	(12,545,410)	0
Net cash flow provided by (used in) financing activities	(896)	64,491,609	0
Increase in cash and cash equivalents	(906)	3,286,960	0
Cash and cash equivalents, beginning of period	1,000	94	94
Cash and cash equivalents, end of period	94	3,287,054	94
Interest paid	0	173,711	0
Supplemental non-cash information:			
Accrued deferred offering costs and other assets	267,592	0	1,181,442
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

Partnership Organization	12 Months Ended
	Dec. 31, 2015
Disclosure Text Block [Abstract]	
Organization, Consolidation and Presentation of Financial Statements Disclosure [Text Block]	**(1) Partnership Organization** Energy 11, L.P., together with its wholly owned subsidiary, (the "Partnership") was formed as a Delaware limited partnership. The initial capitalization of the Partnership of $1,000 occurred on July 9, 2013. The Partnership is offering common units of limited partner interest (the "units") on a "best efforts" basis with the intention of raising up to $2,000,000,000 of capital, consisting of 100,263,158 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 units. The subscribers were admitted as Limited Partners of the Partnership at the initial closing. 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 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 units on a national securities exchange, and (iv) permit holders of units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the 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. Pursuant to the terms of a management agreement, the Partnership has engaged E11 Management, LLC (the "Manager"), to provide management and operating services regarding substantially all aspects of the Partnership's operations. David Lerner Associates, Inc. (the "Managing Dealer"), is the dealer manager for the offering of the units. The Partnership's fiscal year ends on December 31.

Summary of Significant Accounting Policies	12 Months Ended
	Dec. 31, 2015
Accounting Policies [Abstract]	

Significant Accounting Policies [Text Block]	**(2) Summary of Significant Accounting Policies**

Basis of Presentation

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

Cash and Cash Equivalents

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

Offering Costs

The Partnership is raising capital through an on-going best-efforts offering of units by David Lerner Associates, Inc., the managing underwriter, which receives a selling commission and a marketing expense allowance based on proceeds of the units sold. Additionally, the Partnership has incurred other offering costs including legal, accounting and reporting services. These offering costs are recorded by the Partnership as a reduction of shareholders' equity. Prior to the commencement of the Partnership's offering, these costs were deferred and recorded as prepaid expense. As of December 31, 2015, the Partnership had sold 4.5 million units for gross proceeds of $85.2 million and proceeds net of offering costs of $78.3 million.

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, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.

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, 2015, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2015, 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 conducted within the contiguous United States (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 year ended December 31, 2015, relating to the Partnership's asset retirement obligations:

	2015
Asset retirement obligations as of beginning of the year	$ -
Liabilities acquired on December 18, 2015 (Acquisition)	105,000
Accretion of discount (December 18, 2015 to December 31, 2015)	459
Asset retirement obligations as of end of the year	$ 105,459

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 will be 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

There are two principal accounting practices to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner's entitled share of the current period's production (entitlement method). 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, 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 future crude oil, natural gas and NGL prices 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.

Earnings (Loss) Per Common Unit

Basic earnings (loss) per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted earnings (loss) per unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no units with a dilutive effect for the three months and twelve months ended December 31, 2015 and 2014. As a result, basic and diluted outstanding units were the same. The Class B Units and Incentive Distribution Rights are not included in earnings (loss) per common unit until such time that it is probable Payout (as discussed in Note 5) would occur.

Recent Accounting Standard

In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update (“ASU”) 2014-09, Revenue from Contracts with Customers, which will supersede nearly all existing revenue recognition guidance under GAAP. The standard’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard is effective for us on January 1, 2019. Early adoption is not permitted. The standard allows for either “full retrospective” adoption, meaning the standard is applied to all of the periods presented, or “modified retrospective” adoption, meaning the standard is applied only to the most current period presented in the financial statements. We are currently evaluating the transition method that will be elected and the impact, if any, on the Partnership’s financial statements.

In April 2015, the FASB issued an accounting standards update on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for reporting periods beginning after December 15, 2015, and it is not expected to have a material impact on the Partnership's 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, 2015
Oil and Gas Property [Abstract]	
Oil and Gas Properties [Text Block]	**(3) Oil and Gas Investments**

(3) Oil and Gas Investments

On September 15, 2015, the Partnership entered into an Interest Purchase Agreement ("Purchase Agreement") by and among Kaiser-Whiting, LLC and the owners of all the limited liability company interests therein (the "Sellers"), for the purchase of the Sanish Field Assets.

Pursuant to the Purchase Agreement as amended, the purchase price for the Sanish Field Assets consisted of (i) $60 million in cash, subject to customary adjustments, (ii) an aggregate of $2 million, payable in equal amounts on December 31, 2016 and December 31, 2017, (iii) a promissory note in the amount of $97.5 million payable to Sellers (the "Seller Note") and (iv) a contingent payment of up to $95 million. The contingent payment will provide for a sharing between The Partnership and Sellers to the extent the NYMEX current five-year strip oil price for WTI at December 31, 2017 is above $56.61 (with a maximum of $89.00) per barrel. The contingent payment will be calculated as follows: if on December 31, 2017 the average of the monthly NYMEX:CL strip prices for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022 (the "Measurement Date Average Price") is greater than $56.61, then the Sellers will be entitled to a contingent payment equal to (a) (i) the lesser of (A) the Measurement Date Average Price and (B) $89.00, minus (ii) $56.61, multiplied by (b) 586,601 bbls per year for each of the five years from 2018 through 2022 represented by the contracts for the entire acquisition. The contingent consideration is capped at $95 million and is to be paid on January 1, 2018. In addition, the First Amendment provides that so long as the Partnership is not in default under the Seller Note, in lieu of the Partnership's obligation to pay the contingent payment, the Partnership has the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to pay Sellers $5 million in full satisfaction of the contingent payment by paying to Sellers $5 million at the time of election or by increasing the amount of the Seller Note by $5 million.

The following represents the estimated fair values of the assets and liabilities assumed on the acquisition date. The aggregate fair value of consideration transferred was $60.0 million in cash, $94.1 million in seller financed debt, $4.7 million in contingent consideration and $1.7 million in deferred purchase price payments, resulting in no goodwill or bargain purchase gain.

Proved oil, natural gas and NGL properties	$ 159,217,000
Total assets acquired	159,217,000
Asset retirement obligations	105,000
Total liabilities assumed	105,000
Total fair value of net assets	$ 159,112,000

The table above is based upon the original purchase price allocation and is subject to post-closing adjustments.

The Partnership paid $313,366 in transaction costs associated with 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 is a non-operator of the Sanish Field Assets, with Whiting, one of the largest producers in this basin, acting as operator.

The following unaudited pro forma financial information for the periods ended December 31, 2015 and 2014, has been prepared as if the acquisition of the Sanish Field Assets had occurred on January 1, 2014. 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	2014
	Unaudited	
Revenues	$ 26,831,257	$ 49,827,000
Net income	$ 2,336,675	$ 21,437,004

Note Payable	12 Months Ended
	Dec. 31, 2015
Debt Disclosure [Abstract]	
Debt Disclosure [Text Block]	**(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 in the original principal amount of $97.5 million. The note bears interest at 5% per annum and is payable in full no later than September 30, 2016 ("Maturity Date"). The Partnership's right to extend the Maturity Date to March 31, 2017 is subject to the satisfaction of the following conditions: (i) the Partnership must deliver to Seller written notice of the election to extend the Maturity Date no later than September 1, 2016, (ii) the Partnership must pay to Seller an extension fee equal to 0.5% of the outstanding principal balance outstanding at September 30, 2016, (iii) during the extension period and until the note is paid in full, in cash, the interest rate on the outstanding principal amount of the note will bear interest at the fixed rate of 7.0% per annum, (iv) the outstanding principal amount of the note as of September 1, 2016 shall not be in excess of $60 million, and (v) both at the time of the delivery of the extension notice and as of September 30, 2016, no event of default shall exist under the note or any collateral document. There is no penalty for prepayment of the note. Payment of the note is secured by a mortgage and liens on all of the Sanish Field Assets in customary form. If the Partnership has not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership must also pay a deferred origination fee in an amount equal to $250,000. Interest is due monthly on the last day of each month while the note remains outstanding. In addition to interest payments on the outstanding principal balance of the note, the Partnership must make mandatory principal payments monthly in an amount equal to 75% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the note is reduced to $60 million and 50% of the net proceeds the Partnership receives from the sale of its equity securities thereafter, until the note is paid in full. In addition, if the Partnership sells any of the property that is collateral for the note, the Partnership must make a mandatory principal payment equal to 100% of the net proceeds of such sale until the principal amount of the note is paid in full. As of December 31, 2015, the outstanding balance on the note was $85.0 million, the note has a carrying value of $81.7 million which approximates its fair market value.

Capital Contribution and Partners' Equity	12 Months Ended
	Dec. 31, 2015
Partners' Capital Notes [Abstract]	
Partners' Capital Notes Disclosure [Text Block]	**(5) Capital Contribution and Partners' Equity** As of August 19, 2015, the Partnership completed its minimum offering of 1,315,790 common units at $19.00 per common unit. As of December 31, 2015, the Partnership had completed the sale of a total of 4,486,625 common units at $19.00 per common unit for total gross proceeds of $85.2 million and proceeds net of offering costs including selling commissions and marketing expenses of $78.3 million. On March 4, 2016, the Partnership had received subscriptions for all 5,263,158 common units that the Partnership was offering at $19.00 per common unit. The Partnership is continuing the offering at $20.00 per common unit in accordance with the prospectus. As of December 31, 2015, 95,776,533 common units remained unsold. The Partnership will offer common units until January 22, 2017, unless the offering is extended by the General Partner, provided that the offering will be terminated if all of the common units are sold before then. The Partnership intends to continue to raise capital through its "best-efforts" offering of units by David Lerner Associates, Inc. (the "Managing Dealer"). Under the agreement with the Managing Dealer, the Managing Dealer will receive a total of 6% in selling commissions and a marketing expense allowance based on gross proceeds of the units sold. The Managing Dealer 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 units sold ("Incentive Fee"). 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 units. Upon entering into the management agreement with the Manager on August 19, 2015, the Partnership issued 100,000 class B units to an affiliate of the Manager. The class B units provide certain distribution rights described below. Prior to "Payout," which is defined below, all of the distributions made by the Partnership, if any, will be paid to the holders of units. Accordingly, the Partnership will not make any distributions with respect to the Incentive Distribution Rights or with respect to class B units and will not make the contingent, incentive

payments to the Managing Dealer, until Payout occurs.

The Partnership Agreement provides that Payout occurs on the day when the aggregate amount distributed with respect to each of the units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per Unit, regardless of the amount paid for the Unit. If at any time the Partnership distributes to holders of 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, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the Managing Dealer as its contingent, incentive fee until the Managing Dealer receives incentive fees equal to 4% of the gross proceeds of the offering of common units; and then
- Thereafter, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the holders of the units.

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.

Any payments under the Incentive Distribution Rights or Incentive Fee payable to the Managing Dealer will be accounted for as a reduction to Partner's Equity. If payment becomes probable the Partnership will estimate the value of the class B units and record an expense at that time.

For the year ended December 31, 2015, the Partnership paid distributions of $0.510138 per unit or $1,271,730.

Fair Value of Financial Instruments	12 Months Ended Dec. 31, 2015
Fair Value Disclosures [Abstract]	
Fair Value Disclosures [Text Block]	**(6) Fair Value of Financial Instruments**

Fair value of the Partnership's financial instruments approximated carrying value at December 31, 2015.

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 12 months ended December 31, 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 contingent consideration. Within the valuation hierarchy, the Partnership measures the fair value of contingent consideration using Level 3 inputs. As of December 31, 2015, the fair value of contingent consideration was $4,743,752. The following table presents the contingent consideration required to be measured at fair value on a recurring basis as of December 31, 2015.

	December 31, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
	$ -	$ -	$ -	$ -
Liabilities:				
Contingent consideration	$ -	$ -	$ 4,743,752	$ 4,743,752

The contingent consideration as discussed in Note 3 – "Oil and Gas Investments" is a liability that is measured at fair value on a recurring basis for which there is no available quoted market price. The inputs for this instrument are 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 the close date to be $12.5 million. As this is substantially greater than the $5.0 million option, a market participant would likely view the $5.0 million option as highly probable of being exercised and, therefore, value the contingent consideration at $5.0 million, discounted to the expected exercise date. The calculation of this liability is 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 is reflective of the Partnership's market adjusted borrowing rate of 11.15%.

The contingent consideration would increase with a reduction in the discount rate and decrease with an increase in the discount rate. Adjustments to the fair value of the contingent consideration are recorded in the statements of operations.

Related Parties	12 Months Ended Dec. 31, 2015
Related Party Transactions [Abstract]	
Related Party Transactions Disclosure [Text Block]	**(7) Related Parties**

(7) Related Parties

The Partnership has, and is expected to continue to engage in, significant transactions with related parties. These transactions cannot be construed to be at arm's length and the results of the Partnership's operations may be different than if conducted with non-related parties. The General Partner's Board of Directors will oversee and review the Partnership's related party relationships and are required to approve any significant modifications, 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 year ended December 31, 2015 Mr. Merritt was paid $222,099.

Subsequent to completing 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.

During the year ended December 31, 2015, approximately $62,000 of general and administrative costs were incurred by the General Partner and reimbursed by the Partnership.

Management Agreement	12 Months Ended Dec. 31, 2015
Contractors [Abstract]	
Long-term Contracts or Programs Disclosure [Text Block]	**(8) Management Agreement**

(8) Management Agreement

At the initial closing of the sale of common units, August 19, 2015, the Partnership entered into a management services agreement (the "Management Agreement") with E11 Management LLC to provide management and operating services regarding substantially all aspects of the Partnership. The Manager is an indirect, wholly-owned subsidiary of American Energy Partners, L.P. The Manager is not an affiliate of the Partnership or the General Partner.

Under the Management Agreement, the Manager will provide management and other services to the Partnership including the following:

- Identifying producing and non-producing properties that the Partnership may consider acquiring, and assisting in evaluation, contracting for and acquiring these properties and managing the development of these properties;
- Operating, or causing one of its affiliates to operate, on the Partnership's behalf, any properties in which the Partnership interest in the property is sufficient to appoint the operator;
- Overseeing the operations on properties the Partnership acquires that are operated by persons other than the Manager, including recommending whether the Partnership should participate in the development of such properties by the operators of the properties; and

- Assisting in establishing cash management and risk management programs.

The Management Agreement provides that the Partnership will direct the services provided to it under the Management Agreement, and that the Manager will determine the means or method by which those directions are carried out. The Management Agreement provides that the Manager will conduct the day-to-day operations of the Partnership's business as provided in budgets that the Manager will prepare and the Partnership will have the right to approve. The Management Agreement also contains a list of activities in which the Manager will not engage without the Partnership's prior approval.

To date, the Partnership has only purchased non-operated interests in oil and gas assets, which as a result may impact the amount and type of duties needed from the Manager.

The Manager will be reimbursed for certain costs directly related to the Partnership and will be paid a monthly general and administrative expense compensation amount ("Monthly G&A Expense Amount") at an annual rate that will be 1.75% of the net proceeds from the sale of common units, less commissions, marketing fee and offering and organization expense, plus the amount of outstanding indebtedness, which is referred to as the reimbursement base, for the first six months following the initial closing. Thereafter, the Monthly G&A Expense Amount will be at an annual rate of 3.5% of the reimbursement base and will reduce to an annual rate of 2% of the reimbursement base over time. In addition, pursuant to the Partnership Agreement, concurrently with the initial closing of the sale of common units pursuant to the public offering, 100,000 class B units were issued to an affiliate of the Manager.

Subject to certain exceptions, the Management Agreement will remain in effect as long as the Partnership holds any assets.

The Management Agreement is terminable by us if: (i) we sell all or substantially all of our assets; (ii) there is a change in control and the Manager is no longer controlled by Mr. McClendon or his immediate family; (iii) Mr. McClendon, the Manager's key employee, ceases to be employed by the Manager and we do not approve of a proposed replacement of such key employee; (iv) the Manager becomes subject to bankruptcy proceedings; (v) the Manager materially breaches its obligations under the Management Agreement and does not cure the breach within 60 days of its receipt of notice of the breach; or (vi) the Manager or its affiliates defraud us or steal or misappropriate any of our assets and such circumstances have not been cured as provided in the Management Agreement. We may also terminate the Management Agreement if the Manager fails to recommend to us one or more acquisitions of producing or non-producing oil and gas properties that meet our acquisition parameters and are reasonably capable of consummation at any time that we have an aggregate of at least $100 million consisting of capital contributions received by us and which have not been spent by us, and all available borrowings under our credit facility, in each case, that have not been reserved by us for any acquisitions, development operations or other expenses, which we refer to as Unallocated Funds, for a period of 60 consecutive days.

For the year ended December 31, 2015, the Partnership incurred fees of approximately $253,000 and estimated reimbursable costs of approximately $200,000 under the Management Agreement.

See Note 10 – "Subsequent Events" below.

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited)	12 Months Ended Dec. 31, 2015
Oil and Gas Exploration and Production Industries Disclosures [Abstract]	
Oil and Gas Exploration and Production Industries Disclosures [Text Block]	see below

(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, 2015 is as follows:

	2015
Producing properties	$ 90,167,047
Non-producing	69,119,768
	159,286,815
Accumulated depreciation, depletion and amortization	(391,624)
Net capitalized costs	$ 158,895,191

Costs Incurred

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

		2015
Property acquisition costs	$	159,216,768
Development Costs		70,047
	$	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, 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, 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.

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

	Proved Reserves			
	Oil (Barrels)	**NGL (Barrels)**	**Natural Gas (Mcf)**	**Total (BOE)**
January 1, 2015	-	-	-	-

Acquisition	9,089,252	1,866,775	7,705,802	12,240,327
Extensions, discoveries and other additions	-	-	-	-
Production (December 18 - December 31)	(21,937)	(2,841)	(18,392)	(27,843)
December 31, 2015	9,067,315	1,863,934	7,687,410	12,212,484

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

	Proved Developed Reserves				**Proved Undeveloped Reserves**			
	Oil (Barrels)	**NGL (Barrels)**	**Natural Gas (Mcf)**	**Total (BOE)**	**Oil (Barrels)**	**NGL (Barrels)**	**Natural Gas (Mcf)**	**Total (BOE)**
December 31, 2015	5,602,387	961,147	3,964,052	7,224,210	3,464,928	902,787	3,723,358	4,988,274

The following details the changes in proved undeveloped reserves for 2015 (BOE):

Beginning proved undeveloped reserves	-
Acquisition	4,988,274
December 31, 2015	4,988,274

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.

	2015
Future cash inflows	$ 407,928,626
Future production costs	(136,547,001)
Future development costs	(37,640,024)
Future net cash flows	233,741,601
10% annual discount	(134,551,759)
Standardized measure of discounted future net cash flows	$ 99,189,842

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

	2015
Beginning of year	$ -
Changes resulting from:	

Acquisition of reserves	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(480,274)
Net change	99,189,842
End of year	$ 99,189,842

Subsequent Events	12 Months Ended Dec. 31, 2015
Subsequent Events [Abstract]	
Subsequent Events [Text Block]	**(10) Subsequent Events** In January 2016, the Partnership declared and paid $499,061, or $0.111233 per outstanding common unit, in distributions to its holders of common units. In January 2016, the Partnership closed on the issuance of approximately 380,645 units through its ongoing best efforts offering, representing gross proceeds to the Partnership of approximately $7.2 million and proceeds net of selling and marketing costs of approximately $6.8 million. In February 2016, the Partnership declared and paid $522,730, or $0.107397 per outstanding common unit, in distributions to its holders of common units. In February 2016, the Partnership closed on the issuance of approximately 375,483 units through its ongoing best efforts offering, representing gross proceeds to the Partnership of approximately $7.1 million and proceeds net of selling and marketing costs of approximately $6.7 million. On March 4, 2016 we had received subscriptions for all of the common units we were offering at $19.00 per common unit, 5,263,158 units and, consequently, all common units offered and sold after that date will be at $20.00 per common unit in accordance with the prospectus. On March 2, 2016, Aubrey McClendon, who controlled our third party manager E11 Management, LLC was killed in a car accident. We do not believe this will cause any interruption in our existing operations, since as previously disclosed, substantially all of the Partnership’s assets are operated by Whiting Petroleum Corporation, an independent third party. In March 2016, the Partnership declared and paid $563,056, or $0.107397 per outstanding common unit, in distributions to its holders of common units. In March 2016, the Partnership closed on the issuance of approximately 343,541 units through its ongoing best efforts offering, representing gross proceeds to the Partnership of approximately $6.9 million and proceeds net of selling and marketing costs of approximately $6.5 million.

Accounting Policies, by Policy (Policies)	12 Months Ended Dec. 31, 2015
Accounting Policies [Abstract]	
Basis of Accounting, Policy [Policy Text Block]	*Basis of Presentation* The accompanying financial statements of the Partnership have been prepared in accordance with United States generally accepted accounting principles (“US GAAP”).
Cash and Cash Equivalents, 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 on-going best-efforts offering of units by David Lerner Associates, Inc., the managing underwriter, which receives a selling commission and a marketing expense allowance based on proceeds of the units sold. Additionally, the Partnership has incurred other offering costs including legal, accounting and reporting services. These offering costs are recorded by the Partnership as a reduction of shareholders’ equity. Prior to the commencement of the Partnership’s offering, these costs were deferred and recorded as prepaid expense. As of December 31, 2015, the Partnership had sold 4.5 million units for gross proceeds of $85.2 million and proceeds net of offering costs of $78.3 million.
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, including appropriate escalators, are also developed based on a review of actual costs by field or area. Downward revisions in estimates of reserve quantities or expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future cash flows and could indicate a property impairment.
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, 2015, the Partnership did not reserve for bad debt expense, as all amounts are deemed collectible. For the year ended December 31, 2015, 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 conducted within the contiguous United States (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 year ended December 31, 2015, relating to the Partnership's asset retirement obligations:

	2015
Asset retirement obligations as of beginning of the year	$ -
Liabilities acquired on December 18, 2015 (Acquisition)	105,000
Accretion of discount (December 18, 2015 to December 31, 2015)	459
Asset retirement obligations as of end of the year	$ 105,459

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 will be 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* There are two principal accounting practices to account for natural gas imbalances. These methods differ as to whether revenue is recognized based on the actual sale of natural gas (sales method) or an owner's entitled share of the current period's production (entitlement method). 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, 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 future crude oil, natural gas and NGL prices 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]	*Earnings (Loss) Per Common Unit* Basic earnings (loss) per common unit is computed as net loss divided by the weighted average number of common units outstanding during the period. Diluted earnings (loss) per unit is calculated after giving effect to all potential common units that were dilutive and outstanding for the period. There were no units with a dilutive effect for the three months and twelve months ended December 31, 2015 and 2014. As a result, basic and diluted outstanding units were the same. The Class B Units and Incentive Distribution Rights are not included in earnings (loss) per common unit until such time that it is probable Payout (as discussed in Note 5) would occur.
New Accounting Pronouncements, Policy [Policy Text Block]	*Recent Accounting Standard* In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2014-09, Revenue from Contracts with Customers, which will supersede nearly all existing revenue recognition guidance under GAAP. The standard's core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which the company expects to be entitled in exchange for those goods or services. The standard is effective for us on January 1, 2019. Early adoption is not permitted. The standard allows for either "full retrospective" adoption, meaning the standard is applied to all of the periods presented, or "modified retrospective" adoption, meaning the standard is applied only to the most current period presented in the financial statements. We are currently evaluating the transition method that will be elected and the impact, if any, on the Partnership's financial statements. In April 2015, the FASB issued an accounting standards update on the presentation of debt issuance costs. The update requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs is not affected by the update. For public entities, the guidance is effective for reporting periods beginning after December 15, 2015, and it is not expected to have a material impact on the Partnership's 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, 2015
Accounting Policies [Abstract]	
Schedule of Asset Retirement Obligations [Table Text Block]	The following table shows the activity for the year ended December 31, 2015, relating to the Partnership's asset retirement obligations:

	2015
Asset retirement obligations as of beginning of the year	$ -
Liabilities acquired on December 18, 2015 (Acquisition)	105,000

Accretion of discount (December 18, 2015 to December 31, 2015)	459
Asset retirement obligations as of end of the year	$ 105,459

Oil and Gas Investments (Tables)	12 Months Ended Dec. 31, 2015
Oil and Gas Property [Abstract]	
Schedule of Recognized Identified Assets Acquired and Liabilities Assumed [Table Text Block]	The following represents the estimated fair values of the assets and liabilities assumed on the acquisition date. The aggregate fair value of consideration transferred was $60.0 million in cash, $94.1 million in seller financed debt, $4.7 million in contingent consideration and $1.7 million in deferred purchase price payments, resulting in no goodwill or bargain purchase gain.

Proved oil, natural gas and NGL properties	$ 159,217,000
Total assets acquired	159,217,000
Asset retirement obligations	105,000
Total liabilities assumed	105,000
Total fair value of net assets	$ 159,112,000

Business Acquisition, Pro Forma Information [Table Text Block]	The following unaudited pro forma financial information for the periods ended December 31, 2015 and 2014, has been prepared as if the acquisition of the Sanish Field Assets had occurred on January 1, 2014. 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	**2014**
	Unaudited	
Revenues	$ 26,831,257	$ 49,827,000
Net income	$ 2,336,675	$ 21,437,004

Fair Value of Financial Instruments (Tables)	12 Months Ended Dec. 31, 2015
Fair Value Disclosures [Abstract]	
Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis [Table Text Block]	Items required to be measured at fair value on a recurring basis by the Partnership include contingent consideration. Within the valuation hierarchy, the Partnership measures the fair value of contingent consideration using Level 3 inputs. As of December 31, 2015, the fair value of contingent consideration was $4,743,752. The following table presents the contingent consideration required to be measured at fair value on a recurring basis as of December 31, 2015.

	December 31, 2015			
	Level 1	**Level 2**	**Level 3**	**Total**
Assets:				
	$ -	$ -	$ -	$ -
Liabilities:				
Contingent consideration	$ -	$ -	$ 4,743,752	$ 4,743,752

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Tables)	12 Months Ended Dec. 31, 2015
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, 2015 is as follows:

	2015
Producing properties	$ 90,167,047
Non-producing	69,119,768
	159,286,815
Accumulated depreciation, depletion and amortization	(391,624)
Net capitalized costs	$ 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, the Partnership incurred the following costs in oil and natural gas producing activities:

	2015

Property acquisition costs	$	159,216,768
Development Costs		70,047
	$	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, NGL and natural gas reserves are summarized as follows:

	Proved Reserves			
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total (BOE)
January 1, 2015	-	-	-	-
Acquisition	9,089,252	1,866,775	7,705,802	12,240,327
Extensions, discoveries and other additions	-	-	-	-
Production (December 18 - December 31)	(21,937)	(2,841)	(18,392)	(27,843)
December 31, 2015	9,067,315	1,863,934	7,687,410	12,212,484

	Proved Developed Reserves				Proved Undeveloped Reserves			
	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total (BOE)	Oil (Barrels)	NGL (Barrels)	Natural Gas (Mcf)	Total (BOE)
December 31, 2015	5,602,387	961,147	3,964,052	7,224,210	3,464,928	902,787	3,723,358	4,988,274

Beginning proved undeveloped reserves	-
Acquisition	4,988,274
December 31, 2015	4,988,274

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

		2015
Future cash inflows	$	407,928,626
Future production costs		(136,547,001)
Future development costs		(37,640,024)
Future net cash flows		233,741,601
10% annual discount		(134,551,759)
Standardized measure of discounted future net cash flows	$	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:

		2015
Beginning of year	$	-
Changes resulting from:		
Acquisition of reserves		99,670,116
Sales of oil, natural gas and NGLs, net of production costs		(480,274)
Net change		99,189,842
End of year	$	99,189,842

Partnership Organization (Details) - USD ($)	Jul. 09, 2013	12 Months Ended 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 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 units on a national securities exchange, and (iv) permit holders of units to invest in oil and gas properties in a tax efficient basis. The proceeds from the sale of the 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
Limited Liability Company or Limited Partnership, Asset Manager		E11 Management, LLC
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)	6 Months Ended	12 Months Ended	
	Dec. 31, 2013 USD ($)	Dec. 31, 2015 USD ($) shares	Dec. 31, 2014 USD ($) shares
Summary of Significant Accounting Policies (Details) [Line Items]			
Proceeds from Issuance of Common Limited Partners Units		$ 78,286,761	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units	$ 0	$ 78,308,749	$ 0
Number of Operators		2	
Environmental Exit Costs, Costs Accrued to Date		$ 0	
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		4,486,625	
Proceeds from Issuance of Common Limited Partners Units		$ 85,200,000	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units		$ 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	12 Months Ended
	Dec. 31, 2015 USD ($)
Schedule of Asset Retirement Obligations [Abstract]	
Asset retirement obligations as of beginning of the year	$ 0
Liabilities acquired on December 18, 2015 (Acquisition)	105,000
Accretion of discount (December 18, 2015 to December 31, 2015)	459
Asset retirement obligations as of end of the year	$ 105,459

Oil and Gas Investments (Details) - USD ($)		6 Months Ended	12 Months Ended	
	Sep. 15, 2015	Dec. 31, 2013	Dec. 31, 2015	Dec. 31, 2014
Oil and Gas Investments (Details) [Line Items]				
Payments to Acquire Oil and Gas Property		$ 0	$ 60,000,000	$ 0
Business Combination, Contingent Consideration, Liability			4,743,752	
Notes Payable, Other Payables [Member]				
Oil and Gas Investments (Details) [Line Items]				
Debt Instrument, Face Amount			97,500,000	
Sanish Field Located in Mountrail County, North Dakota [Member]				
Oil and Gas Investments (Details) [Line Items]				

Oil Wells Purchase Agreement, Purchase Price Description	(i) $60 million in cash, subject to customary adjustments, (ii) an aggregate of $2 million, payable in equal amounts on December 31, 2016 and December 31, 2017, (iii) a promissory note in the amount of $97.5 million payable to Sellers (the “Seller Note”) and (iv) a contingent payment of up to $95 million. The contingent payment will provide for a sharing between The Partnership and Sellers to the extent the NYMEX current five-year strip oil price for WTI at December 31, 2017 is above $56.61 (with a maximum of $89.00) per barrel. The contingent payment will be calculated as follows: if on December 31, 2017 the average of the monthly NYMEX:CL strip prices for future contracts during the delivery period beginning December 31, 2017 and ending December 31, 2022 (the “Measurement Date Average Price”) is greater than $56.61, then the Sellers will be entitled to a contingent payment equal to (a) (i) the lesser of (A) the Measurement Date Average Price and (B) $89.00, minus (ii) $56.61, multiplied by (b) 586,601 bbls per year for each of the five years from 2018 through 2022 represented by the contracts for the entire acquisition. The contingent consideration is capped at $95 million and is to be paid on January 1, 2018. In addition, the First Amendment provides that so long as the Partnership is not in default under the Seller Note, in lieu of the Partnership’s obligation to pay the contingent payment, the Partnership has the one-time right (exercisable between June 15, 2016 through June 30, 2016) to elect to pay Sellers $5 million in full satisfaction of the contingent payment by paying to Sellers $5 million at the time of election or by increasing the amount of the Seller Note by $5 million.			
Payments to Acquire Oil and Gas Property	$ 60,000,000			
Business Combination, Contingent Consideration Arrangements, Range of Outcomes, Value, High	95,000,000			
Business Combination, Consideration Transferred, Liabilities Incurred	94,100,000			
Business Combination, Contingent Consideration, Liability	4,700,000		$ 4,743,752	
Business Combination, Deferred Purchase Price Payments	1,700,000			
Goodwill	0			
Business Combination, Bargain Purchase, Gain Recognized, Amount	0			
Acquisition Costs, Period Cost	313,366			
Sanish Field Located in Mountrail County, North Dakota [Member] | Equal Amounts Payable on December 31, 2016 and 2017 [Member]				
Oil and Gas Investments (Details) [Line Items]				
Debt Instrument, Face Amount	2,000,000			
Sanish Field Located in Mountrail County, North Dakota [Member] | Seller Note [Member] | Notes Payable, Other Payables [Member]				
Oil and Gas Investments (Details) [Line Items]				
Debt Instrument, Face Amount	$ 97,500,000			

Oil and Gas Investments (Details) - Schedule of Recognized Identified Assets Acquired and Liabilities Assumed	Sep. 15, 2015 USD ($)
Schedule of Recognized Identified Assets Acquired and Liabilities Assumed [Abstract]	
Proved oil, natural gas and NGL properties	$ 159,217,000
Total assets acquired	159,217,000
Asset retirement obligations	105,000
Total liabilities assumed	105,000
Total fair value of net assets	$ 159,112,000

Oil and Gas Investments (Details) - Business Acquisition, Pro Forma Information - USD ($)	12 Months Ended	
	Dec. 31, 2015	Dec. 31, 2014
Business Acquisition, Pro Forma Information [Abstract]		
Revenues	$ 26,831,257	$ 49,827,000
Net income	$ 2,336,675	$ 21,437,004

Note Payable (Details) - Notes Payable, Other Payables [Member]	12 Months Ended
	Dec. 31, 2015 USD ($)
Note Payable (Details) [Line Items]	
Debt Instrument, Face Amount	$ 97,500,000
Debt Instrument, Interest Rate, Stated Percentage	5.00%
Debt Instrument, Maturity Date	Sep. 30, 2016
Debt Instrument, Maturity Date, Description	The Partnership's right to extend the Maturity Date to March 31, 2017 is subject to the satisfaction of the following conditions: (i) the Partnership must deliver to Seller written notice of the election to extend the Maturity Date no later than September 1, 2016, (ii) the Partnership must pay to Seller an extension fee equal to 0.5% of the outstanding principal balance outstanding at September 30, 2016, (iii) during the extension period and until the note is paid in full, in cash, the interest rate on the outstanding principal amount of the note will bear interest at the fixed rate of 7.0% per annum, (iv) the outstanding principal amount of the note as of September 1, 2016 shall not be in excess of $60 million, and (v) both at the time of the delivery of the extension notice and as of September 30, 2016, no event of default shall exist under the note or any collateral document. There is no penalty for prepayment of the note.
Debt Instrument, Collateral	Payment of the note is secured by a mortgage and liens on all of the Sanish Field Assets in customary form.
Debt Instrument, Description	If the Partnership has not fully repaid all amounts outstanding under the note on or before June 30, 2016, the Partnership must also pay a deferred origination fee in an amount equal to $250,000.
Debt Instrument, Fee Amount	$ 250,000
Debt Instrument, Payment Terms	Interest is due monthly on the last day of each month while the note remains outstanding. In addition to interest payments on the outstanding principal balance of the note, the Partnership must make mandatory principal payments monthly in an amount equal to 75% of the net proceeds the Partnership receives from the sale of its equity securities until the principal amount of the note is reduced to $60 million and 50% of the net proceeds the Partnership receives from the sale of its equity securities thereafter, until the note is paid in full. In addition, if the Partnership sells any of the property that is collateral for the note, the Partnership must make a mandatory principal payment equal to 100% of the net proceeds of such sale until the principal amount of the note is paid in full.
Debt Instrument, Outstanding Balance	$ 85,000,000
Notes Payable	$ 81,700,000

Capital Contribution and Partners' Equity (Details) - USD ($)		1 Months Ended			6 Months Ended	12 Months Ended	
	Mar. 04, 2016	Mar. 28, 2016	Feb. 29, 2016	Jan. 31, 2016	Dec. 31, 2013	Dec. 31, 2015	Dec. 31, 2014
Capital Contribution and Partners' Equity (Details) [Line Items]							
Proceeds from Issuance of Common Limited Partners Units						$ 78,286,761	
Managing Dealer, Selling Commissions, Percentage						6.00%	
Managing Dealer, Maximum Contingent Incentive Fee on Gross Proceeds, Percentage						4.00%	
Class B Units Issued to Manager (in Shares)						100,000	
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 units equals $20.00 plus the Payout Accrual. The Partnership Agreement defines "Payout Accrual" as 7% per annum simple interest accrued monthly until paid on the Net Investment Amount outstanding from time to time. The Partnership Agreement defines Net Investment Amount initially as $20.00 per Unit, regardless of the amount paid for the Unit. If at any time the Partnership distributes to holders of 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, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the Managing Dealer as its contingent, incentive fee until the Managing Dealer receives incentive fees equal to 4% of the gross proceeds of the offering of common units; and then· Thereafter, 35% to the holders of the Incentive Distribution Rights, 35% to the holders of the class B units and 30% to the holders of the units.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)						$ 0.510138	
Distribution Made to Limited Partner, Cash Distributions Paid					$ 0	$ 1,271,730	$ 0
Subsequent Event [Member]							
Capital Contribution and Partners' Equity (Details) [Line Items]							
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)		$ 0.107397	$ 0.107397	$ 0.111233			
Distribution Made to Limited Partner, Cash Distributions Paid		$ 563,056	$ 522,730	$ 499,061			
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	
Partners' Capital Account, Units, Sale of Units (in Shares)						4,486,625	
Proceeds from Issuance of Common Limited Partners Units						$ 85,200,000	
Proceeds, Net of Selling Commissions and Marketing Expenses, from Issuance of Common Limited Partners Units						$ 78,300,000	
Stock or Units Available for Distributions (in Shares)						95,776,533	
Partners' Capital Account, Description of Units Sold						The Partnership intends to continue to raise capital through its “best-efforts” offering of units by David Lerner Associates, Inc. (the “Managing Dealer”).	
Best-Efforts Offering [Member] | Subsequent Event [Member]							
Capital Contribution and Partners' Equity (Details) [Line Items]							
Partners Capital Account, Units Sold, Price Per Unit	$ 19.00	$ 20.00					
Partners' Capital Account, Units, Sale of Units (in Shares)	5,263,158	343,541	375,483	380,645			
Proceeds from Issuance of Common Limited Partners Units		$ 6,900,000	$ 7,100,000	$ 7,200,000			

Fair Value of Financial Instruments (Details) - USD ($)	12 Months Ended	
	Dec. 31, 2015	Sep. 15, 2015
Fair Value of Financial Instruments (Details) [Line Items]		
Business Combination, Contingent Consideration, Liability	$ 4,743,752	
Fair Value Inputs, Discount Rate	10.00%	

Sanish Field Located in Mountrail County, North Dakota [Member]		
Fair Value of Financial Instruments (Details) [Line Items]		
Business Combination, Contingent Consideration, Liability	$ 4,743,752	$ 4,700,000
Fair Value Measurements, Valuation Processes, Description	Management calculated the fair value of the contingent consideration (absent the $5.0 million option) as of the close date to be $12.5 million. As this is substantially greater than the $5.0 million option, a market participant would likely view the $5.0 million option as highly probable of being exercised and, therefore, value the contingent consideration at $5.0 million, discounted to the expected exercise date. The calculation of this liability is 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 is reflective of the Partnership's market adjusted borrowing rate 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

Fair Value of Financial Instruments (Details) - Schedule of Fair Value, Assets and Liabilities Measured on Recurring Basis	Dec. 31, 2015 USD ($)
Assets:	
	$ 0
Liabilities:	
Contingent consideration	4,743,752
Fair Value, Inputs, Level 1 [Member]	
Assets:	
	0
Liabilities:	
Contingent consideration	0
Fair Value, Inputs, Level 2 [Member]	
Assets:	
	0
Liabilities:	
Contingent consideration	0
Fair Value, Inputs, Level 3 [Member]	
Assets:	
	0
Liabilities:	
Contingent consideration	$ 4,743,752

Related Parties (Details)	12 Months Ended
	Dec. 31, 2015 USD ($)
General Partner [Member]	
Related Parties (Details) [Line Items]	
Related Party Transaction, Selling, General and Administrative Expenses from Transactions with Related Party	$ 62,000
Consulting Services Provided to General Partner [Member] | President [Member]	
Related Parties (Details) [Line Items]	
Costs and Expenses, Related Party	222,099
Reimbursement of Offering Related Cost [Member] | General Partner [Member]	
Related Parties (Details) [Line Items]	
General Partner Reimbursement	$ 1,800,000

Management Agreement (Details) - USD ($)	6 Months Ended	12 Months Ended	
	Dec. 31,	Dec. 31, 2015	Dec. 31,

	2013		2014
Contractors [Abstract]			
Reimbursable Costs on Long Term Contracts or Programs, Description		The Manager will be reimbursed for certain costs directly related to the Partnership and will be paid a monthly general and administrative expense compensation amount ("Monthly G&A Expense Amount") at an annual rate that will be 1.75% of the net proceeds from the sale of common units, less commissions, marketing fee and offering and organization expense, plus the amount of outstanding indebtedness, which is referred to as the reimbursement base, for the first six months following the initial closing. Thereafter, the Monthly G&A Expense Amount will be at an annual rate of 3.5% of the reimbursement base and will reduce to an annual rate of 2% of the reimbursement base over time. In addition, pursuant to the Partnership Agreement, concurrently with the initial closing of the sale of common units pursuant to the public offering, 100,000 class B units were issued to an affiliate of the Manager.	
Class B Units Issued to Manager		100,000	
Management Termination Description		(i) we sell all or substantially all of our assets; (ii) there is a change in control and the Manager is no longer controlled by Mr. McClendon or his immediate family; (iii) Mr. McClendon, the Manager's key employee, ceases to be employed by the Manager and we do not approve of a proposed replacement of such key employee; (iv) the Manager becomes subject to bankruptcy proceedings; (v) the Manager materially breaches its obligations under the Management Agreement and does not cure the breach within 60 days of its receipt of notice of the breach; or (vi) the Manager or its affiliates defraud us or steal or misappropriate any of our assets and such circumstances have not been cured as provided in the Management Agreement. We may also terminate the Management Agreement if the Manager fails to recommend to us one or more acquisitions of producing or non-producing oil and gas properties that meet our acquisition parameters and are reasonably capable of consummation at any time that we have an aggregate of at least $100 million consisting of capital contributions received by us and which have not been spent by us, and all available borrowings under our credit facility, in each case, that have not been reserved by us for any acquisitions, development operations or other expenses, which we refer to as Unallocated Funds, for a period of 60 consecutive days.	
Owned Property Management Costs	$ 0	$ 252,524	$ 0
Owned Property, Reimbursable Management Costs		$ 200,000	

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details)	12 Months Ended Dec. 31, 2015 $ / bbl $ / MMBTU
Oil [Member] | Before Price Differentials [Member]	
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]	
Average Sales Prices	50.28
Oil [Member] | Including Effect of Price Differential Adjustments [Member]	
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]	
Average Sales Prices	41.74
Natural Gas [Member] | Before Price Differentials [Member]	
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]	
Average Sales Prices | $ / MMBTU	2.59
Natural Gas [Member] | Including Effect of Price Differential Adjustments [Member]	
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]	
Average Sales Prices | $ / MMBTU	1.46
Natural Gas Liquids [Member] | Before Price Differentials [Member]	
Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]	
Average Sales Prices	15.74
Natural Gas Liquids [Member] | Including Effect of Price Differential Adjustments [Member]	
Supplementary Information on Oil,	

Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) [Line Items]	
Average Sales Prices	9.77

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Capitalized Cost Relating to Oil and Gas Producing Activities Disclosure	Dec. 31, 2015 USD ($)
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]	
	$ 159,286,815
Accumulated depreciation, depletion and amortization	(391,624)
Net capitalized costs	158,895,191
Producing Properties [Member]	
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]	
Proved properties	90,167,047
Non-Producing Properties [Member]	
Capitalized Costs Relating to Oil and Gas Producing Activities, by Geographic Area [Line Items]	
Proved properties	$ 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	12 Months Ended
	Dec. 31, 2015 USD ($)
Cost Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities Disclosure [Abstract]	
Property acquisition costs	$ 159,216,768
Development Costs	70,047
	$ 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 Quantities	12 Months Ended
	Dec. 31, 2015 Boe bbl Mcf
Reserve Quantities [Line Items]	
January 1, 2015 (in Barrels of Oil Equivalent) | Boe	0
December 31, 2015 (in Barrels of Oil Equivalent) | Boe	12,212,484
December 31, 2015 (in Barrels of Oil Equivalent) | Boe	7,224,210
December 31, 2015 (in Barrels of Oil Equivalent) | Boe	4,988,274
Beginning proved undeveloped reserves (in Barrels of Oil Equivalent) | Boe	0
Acquisition (in Barrels of Oil Equivalent) | Boe	12,240,327
Extensions, discoveries and other additions (in Barrels of Oil Equivalent) | Boe	0
Production (December 18 - December 31) (in Barrels of Oil Equivalent) | Boe	(27,843)
Acquisition (in Barrels of Oil Equivalent) | Boe	4,988,274
Oil [Member]	
Reserve Quantities [Line Items]	
January 1, 2015	0
December 31, 2015	9,067,315
December 31, 2015	5,602,387

December 31, 2015	3,464,928
Acquisition	9,089,252
Extensions, discoveries and other additions	0
Production (December 18 - December 31)	(21,937)
Natural Gas Liquids [Member]	
Reserve Quantities [Line Items]	
January 1, 2015	0
December 31, 2015	1,863,934
December 31, 2015	961,147
December 31, 2015	902,787
Acquisition	1,866,775
Extensions, discoveries and other additions	0
Production (December 18 - December 31)	(2,841)
Natural Gas [Member]	
Reserve Quantities [Line Items]	
January 1, 2015 | Mcf	0
December 31, 2015 | Mcf	7,687,410
December 31, 2015 | Mcf	3,964,052
December 31, 2015 | Mcf	3,723,358
Acquisition | Mcf	7,705,802
Extensions, discoveries and other additions | Mcf	0
Production (December 18 - December 31) | Mcf	(18,392)

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Standarized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure - USD ($)	Dec. 31, 2015	Dec. 31, 2014
Standarized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]		
Future cash inflows	$ 407,928,626	
Future production costs	(136,547,001)	
Future development costs	(37,640,024)	
Future net cash flows	233,741,601	
10% annual discount	(134,551,759)	
Standardized measure of discounted future net cash flows	$ 99,189,842	$ 0

Supplementary Information on Oil, Natural Gas and Natural Gas Liquid Reserves (Unaudited) (Details) - Standarized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure (Parentheticals)	12 Months Ended
	Dec. 31, 2015
Standarized Measure of Discounted Future Cash Flows Relating to Proved Reserves Disclosure [Abstract]	
Annual discount	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	12 Months Ended
	Dec. 31, 2015 USD ($)
Schedule of Changes in Standardized Measure of Discounted Future Net Cash Flows [Abstract]	
Beginning of year	$ 0
Changes resulting from:	

Acquisition of reserves	99,670,116
Sales of oil, natural gas and NGLs, net of production costs	(480,274)
Net change	99,189,842
End of year	$ 99,189,842

Subsequent Events (Details) - USD ($)		1 Months Ended			6 Months Ended	12 Months Ended	
	Mar. 04, 2016	Mar. 28, 2016	Feb. 29, 2016	Jan. 31, 2016	Dec. 31, 2013	Dec. 31, 2015	Dec. 31, 2014
Subsequent Events (Details) [Line Items]							
Distribution Made to Limited Partner, Cash Distributions Paid					$ 0	$ 1,271,730	$ 0
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)						$ 0.510138	
Proceeds from Issuance of Common Limited Partners Units						$ 78,286,761	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units					$ 0	$ 78,308,749	$ 0
Subsequent Event [Member]							
Subsequent Events (Details) [Line Items]							
Distribution Made to Limited Partner, Cash Distributions Paid		$ 563,056	$ 522,730	$ 499,061			
Distribution Made to Limited Partner, Distributions Paid, Per Unit (in Dollars per share)		$ 0.107397	$ 0.107397	$ 0.111233			
Best-Efforts Offering [Member]							
Subsequent Events (Details) [Line Items]							
Partners' Capital Account, Units, Sale of Units (in Shares)						4,486,625	
Proceeds from Issuance of Common Limited Partners Units						$ 85,200,000	
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units						78,300,000	
Partners Capital Account, Units Sold, Price Per Unit						$ 19.00	
Best-Efforts Offering [Member] | Subsequent Event [Member]							
Subsequent Events (Details) [Line Items]							
Partners' Capital Account, Units, Sale of Units (in Shares)	5,263,158	343,541	375,483	380,645			
Proceeds from Issuance of Common Limited Partners Units		$ 6,900,000	$ 7,100,000	$ 7,200,000			
Proceeds, Net of Offering Costs, from Issuance of Common Limited Partners Units		6,500,000	$ 6,700,000	$ 6,800,000			
Partners Capital Account, Units Sold, Price Per Unit	$ 19.00	$ 20.00					

Energy 11, L.P. (Filer) CIK: 0001581552 (see all company filings)

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