# FORM 10-K

Annual report pursuant to section 13 and 15(d)

Filing Date: **2017-02-27** | Period of Report: **2016-12-31**
**SEC Accession No.** 0001214659-17-001450

(HTML Version on secdatabase.com)

## FILER

**Ridgewood Energy O Fund LLC**

CIK:**1315061**| IRS No.: **000000000** | State of Incorp.:**DE** | Fiscal Year End: **1231**
Type: **10-K** | Act: **34** | File No.: **000-51924** | Film No.: **17642924**
SIC: **1382** Oil & gas field exploration services

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

# FORM 10-K

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

**For the fiscal year ended December 31, 2016**
**or**
☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

**For the transition period from _____ to _____**

**Commission File No. 000-51924**

# Ridgewood Energy O Fund, LLC

(Exact name of registrant as specified in its charter)

| | |
|---|---|
| **Delaware** | **76-0774429** |
| (State or other jurisdiction of incorporation or organization) | (I.R.S. Employer Identification No.) |

**14 Philips Parkway, Montvale, NJ 07645**
(Address of principal executive offices) (Zip code)
**(800) 942-5550**
(Registrant's telephone number, including area code)

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

Shares of LLC Membership Interest

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

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

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

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

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

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

| | | | |
|---|---|---|---|
| Large accelerated filer | ☐ | Accelerated filer | ☐ |
| Non-accelerated filer (Do not check if a smaller reporting company) | ☐ | Smaller reporting company | ☒ |

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

There is no market for the shares of LLC Membership Interest in the Fund. As of February 27, 2017 there were 870.6486 shares of LLC Membership Interest outstanding.

**RIDGEWOOD ENERGY O FUND, LLC**
**2016 ANNUAL REPORT ON FORM 10-K**
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**FORWARD-LOOKING STATEMENTS**

Certain statements in this Annual Report on Form 10-K (“Annual Report”) and the documents Ridgewood Energy O Fund, LLC (the “Fund”) has incorporated by reference into this Annual Report, other than purely historical information, including estimates, projections and statements relating to the Fund’s business plans, strategies, objectives and expected operating results, and the assumptions upon which those statements are based, are “forward-looking statements” within the meaning of the U.S. Private Securities Litigation Reform Act of 1995 that are based on current expectations and assumptions and are subject to risks and uncertainties that may cause actual results to differ materially from the forward-looking statements. You are therefore cautioned against relying on any such forward-looking statements. Forward-looking statements can generally be identified by words such as “believe,” “project,” “expect,” “anticipate,” “estimate,” “intend,” “strategy,” “plan,” “target,” “pursue,” “may,” “will,” “will likely result,” and similar expressions and references to future periods. Examples of events that could cause actual results to differ materially from historical results or those anticipated include weather conditions, such as hurricanes, changes in market and other conditions affecting the pricing, production and demand of oil and natural gas, the cost and availability of equipment, and changes in domestic and foreign governmental regulations, as well as other risks and uncertainties discussed in this Annual Report in Item 1. “Business” and Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations”. Examples of forward-looking statements made herein include statements regarding projects, investments, insurance, capital expenditures and liquidity. Forward-looking statements made in this document speak only as of the date on which they are made. The Fund undertakes no obligation to update or revise publicly any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

# PART I

## ITEM 1. BUSINESS

### Overview

The Fund is a Delaware limited liability company ("LLC") formed on December 21, 2004 to primarily acquire interests in oil and natural gas properties located in the United States offshore waters of Texas, Louisiana and Alabama in the Gulf of Mexico.

The Fund initiated its private placement offering on February 16, 2005, selling whole and fractional shares of LLC membership interests ("Shares"), primarily at $150 thousand per whole Share. There is no public market for the Shares and one is not likely to develop. In addition, the Shares are subject to material restrictions on transfer and resale and cannot be transferred or resold except in accordance with the Fund's limited liability company agreement (the "LLC Agreement") and applicable federal and state securities laws. The private placement offering was terminated on August 31, 2005. The Fund raised $129.0 million and, after payment of $20.6 million in offering fees, commissions and investment fees, the Fund had $108.4 million for investments and operating expenses.

### Manager

Ridgewood Energy Corporation (the "Manager" or "Ridgewood Energy") was founded in 1982. The Manager has direct and exclusive control over the management of the Fund's operations. The Manager performs, or arranges for the performance of, the management, advisory and administrative services required for Fund operations. Such services include, without limitation, the administration of shareholder accounts, shareholder relations and the preparation, review and dissemination of tax and other financial information and the management of the Fund's investments in projects. In addition, the Manager provides office space, equipment and facilities and other services necessary for Fund operations. The Manager also engages and manages contractual relations with unaffiliated custodians, depositories, accountants, attorneys, corporate fiduciaries, insurers, banks and others as required. Historically, when the Fund sought project investment, the Manager located potential projects, conducted due diligence, and negotiated the investment transactions with respect to those projects. Additional information regarding the Manager is available through its website at www.ridgewoodenergy.com. No information on such website shall be deemed to be included or incorporated by reference into this Annual Report.

As compensation for its services, the Manager is entitled to an annual management fee, payable monthly, equal to 2.5% of the total capital contributions made by the Fund's shareholders, net of cumulative dry-hole and related well costs incurred by the Fund. The Manager is entitled to receive an annual management fee from the Fund regardless of the Fund's profitability in that year. Management fees during the years ended December 31, 2016 and 2015 were $1.3 million and $1.4 million, respectively. Additionally, the Manager is entitled to receive a 15% interest in cash distributions from operations made by the Fund. The Fund did not pay distributions during the year ended December 31, 2016. Distributions paid to the Manager during the year ended December 31, 2015 were $27 thousand.

In addition to the management fee, the Fund is required to pay all other expenses it may incur, including insurance premiums, expenses of preparing and printing periodic reports for shareholders and the Securities Exchange Commission ("SEC"), commission fees, taxes, third-party legal, accounting and consulting fees, litigation expenses and other expenses. The Fund is required to reimburse the Manager for all such expenses paid on its behalf.

### Business Strategy

The Fund's primary investment objective is to generate cash flow for distribution to its shareholders by generating returns across a portfolio of exploratory or development oil and natural gas projects. Distributions are funded from cash flow from operations, and the frequency and amount are within the Manager's discretion subject to available cash from operations, reserve requirements and Fund operations. The Fund has invested in the drilling and development of both shallow and deepwater oil and natural gas projects in the U.S. offshore waters of Texas, Louisiana and Alabama in the Gulf of Mexico, in partnership with exploration and production companies. The Fund does not expect in the future to investigate or invest in any additional projects other than those in which it currently has a working interest, as discussed below under the heading "Properties" in this Item 1. "Business" of this Annual Report. The Fund's remaining capital has been fully allocated to complete such projects.

The Fund has invested its capital with operators through working interest joint ventures with such operators and other energy companies that also own or acquire working interests in the projects. A working interest is an undivided fractional interest in a lease block acquired from the U.S. government or from an operator that has acquired the working interest. A working interest includes the right to drill, produce and conduct operating activities and share in any resulting oil and natural gas production. Operators will generally retain 25% to 50% interests in multiple drilling projects, rather than 100% interests in a few projects, in order to share risk, obtain independent technical validation and stretch exploration budgets that are split across numerous regions of the world.

*Investment Committee*
Ridgewood Energy maintains an investment committee consisting of five members, all of whom are employees of the Manager (the "Investment Committee"). The Investment Committee provides operational, financial, scientific and technical oil and gas expertise to the Fund and generally approves investments and other matters for the Fund. Two members of the Investment Committee are based out of the Manager's Montvale, New Jersey office and three members are based out of the Manager's Houston, Texas office. Currently, the Investment Committee's activities surrounding the Fund are principally related to the development and operation of properties in which it already has a working interest.

*Participation and Joint Operating Agreements*
On behalf of the Fund, and with respect to the Fund's projects, Ridgewood Energy negotiated participation and joint operating agreements. Under the joint operating agreement, proposals and decisions with respect to a project and related activities are generally made based on percentage ownership approvals and although an operator's percentage ownership may constitute a majority ownership, operators generally seek consensus relating to project decisions. As a result, Ridgewood Energy and other non-operating partners generally retain the right to make proposals and influence decisions involving certain operational matters associated with a project. This approval discretion and the operator's desire to execute the project efficiently and expeditiously can function to limit the operator's inclination to act on its own, or against the interests of the participants in the project.

**Project Information**

The Fund's existing projects are located in the waters of the Gulf of Mexico, offshore Louisiana, on the Outer Continental Shelf ("OCS"). The Outer Continental Shelf Lands Act ("OCSLA"), which was enacted in 1953, governs certain activities with respect to working interests and the exploration of oil and natural gas in the OCS. See further discussion under the heading "Regulation" in this Item 1. "Business" of this Annual Report.

Leases in the OCS are generally issued for a primary lease term of 5, 8 or 10 years, depending on the water depth of the lease block. During a primary lease term, except in limited circumstances, lessees are not subject to any particular requirements to conduct exploratory or development activities. However, once a lessee drills a well and begins production, the lease term is extended for the duration of commercial production.

The lessee of a particular block, for the term of the lease, has the right to drill and develop exploratory wells and conduct other activities throughout the block. If the initial well on the block is successful, a lessee, or third-party operator for a project, may conduct additional geological studies and may determine to drill additional exploratory or development wells. If a development well is to be drilled in the block, each lessee owning working interests in the block must be offered the opportunity to participate in, and cover the costs of, the development well up to that particular lessee's working interest ownership percentage.

*Royalty Payments*
Generally, working interests in an offshore oil and natural gas lease under the OCSLA pay a 12.5%, 16.67% or 18.75% royalty to the Office of Natural Resources Revenue ("ONRR") depending on the lease. Other than the ONRR royalties, the Fund does not have material royalty burdens other than as provided by the terms of the Fund's credit agreement, which will require the Fund to pay royalties from the Beta Project to the lender. See Note 3 of "Notes to Financial Statements" – "Credit Agreement – Beta Project Financing" contained in Item 8. "Financial Statements and Supplementary Data" within this Annual Report for more information regarding the credit agreement.

*Deep Gas Royalty Relief*
On January 26, 2004, the Bureau of Ocean Energy Management ("BOEM"), an agency of the United States Department of Interior, promulgated a rule providing incentives for companies to increase deep natural gas production in the Gulf of Mexico (the "Royalty Relief Rule"). The Royalty Relief Rule does not extend to deep waters of the Gulf of Mexico off the OCS nor does it apply if the price of natural gas exceeds $11.60 (estimated) per Million British Thermal Units ("mmbtu"), adjusted annually for inflation. The Fund currently has one project, the Cobalt Project, which qualifies for royalty relief under the Royalty Relief Rule.

*Deepwater Royalty Relief*

In addition to the Royalty Relief Rule, the Deep Water Royalty Relief Act of 1995 (the "Deepwater Royalty Relief Act") was enacted to promote exploration and production of oil and natural gas in the deepwater of the Gulf of Mexico and relieves eligible leases from paying royalties to the U.S. Government on certain defined amounts of deepwater production. The Deepwater Royalty Relief Act expired in the year 2000 but was extended for qualified leases by the BOEM to promote continued interest in deepwater. The Deepwater Royalty Relief Act does not apply to oil if the prices of oil exceed certain thresholds (currently estimated to be between $37.30 per barrel and $48.43 per barrel), adjusted annually for inflation. The Deepwater Royalty Relief Act does not apply to natural gas if the prices of natural gas exceed certain thresholds (currently estimated to be between $4.66 per mmbtu and $8.07 per mmbtu) adjusted annually for inflation. The Fund currently has four projects, the Liberty, Diller, Marmalard and Beta projects, which qualify for royalty relief under the Deepwater Royalty Relief Act.

**Properties**

*Productive Wells*

The following table sets forth the number of productive oil and natural gas wells in which the Fund owned an interest as of December 31, 2016. Productive wells are producing wells and wells mechanically capable of production. Gross wells are the total number of wells in which the Fund owns a working interest. Net wells are the sum of the Fund's fractional working interests owned in the gross wells. All of the wells, each of which produces both oil and natural gas, are located in the offshore waters of the Gulf of Mexico and are operated by third-party operators.

| | Total Productive Wells | |
|---|---|---|
| | Gross | Net |
| Oil and natural gas | 12 | 0.50 |

*Acreage Data*

The following table sets forth the Fund's interests in developed and undeveloped oil and gas acreage as of December 31, 2016. Gross acres are the total number of acres in which the Fund owns a working interest. Net acres are the sum of the fractional working interests owned in gross acres. Ownership interests generally take the form of working interests in oil and gas leases that have varying terms. All of the wells are located in the offshore waters of the Gulf of Mexico and are operated by third-party operators.

| Developed Acres | | Undeveloped Acres | |
|---|---|---|---|
| Gross | Net | Gross | Net |
| 44,520 | 2,048 | 17,280 | 389 |

Information regarding the Fund's current projects, all of which are located in the offshore waters of the Gulf of Mexico, is provided in the following table. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report under the heading "Liquidity Needs" for information regarding the funding of the Fund's capital commitments.

| Project | Working Interest | | Total Spent through December 31, 2016 | | Total Fund Budget | Status |
|---|---|---|---|---|---|---|
| | | | (in thousands) | | | |
| **Producing Properties** | | | | | | |
| Beta Project | 5.0% | $ | 37,843 | $ | 46,388 | The Beta Project is expected to include the development of four wells. Well #1 commenced production during third quarter 2016. Well #2 commenced production during fourth quarter 2016. Wells #3 and #4 are expected to commence production in 2017. The Fund expects to spend $6.2 million for additional development costs and $2.3 million for asset retirement obligations. |
| Cobalt Project | 4.0% | $ | 1,894 | $ | 1,997 | The Cobalt Project, a single-well project, commenced production in 2009. Recompletions are planned for 2017 and 2018 at an estimated total cost of $48 thousand. The Fund expects to spend $0.1 million for asset retirement obligations. |
| Diller Project | 0.88% | $ | 2,787 | $ | 3,938 | The Diller Project is expected to include the development of two wells. Well #1 commenced production during third quarter 2015. Well #2 is expected to commence production in 2019. Well #1, which was shut-in in late-2016 due to well hydrate remediation work, resumed production in mid-January 2017. The Fund expects to spend $0.8 million for additional development costs and $0.4 million for asset retirement obligations. |
| Eugene Island 346/347 | 5.0% | $ | 4,197 | $ | 4,501 | Eugene Island 346/347 consists of two wells, which commenced production in 2008. Both wells, which have been shut-in periodically since 2015, are producing at nominal rates and nearing the end of their productive lives. The Fund expects to spend $0.3 million for asset retirement obligations. |
| Liberty Project | 5.0% | $ | 5,578 | $ | 6,680 | The Liberty Project, a single-well project, commenced production in 2010. After various shut-ins in late-2015 and early-2016, due to third-party facilities' repair and maintenance activities, the well resumed production in early-May 2016. A smart recompletion is planned for 2018 with no costs to the Fund. The Fund expects to spend $1.1 million for asset retirement obligations. |
| Marmalard Project | 0.88% | $ | 5,597 | $ | 9,329 | The Marmalard Project is expected to include the development of six wells. Wells #1, #2 and #3 commenced production during second quarter 2015. Well #4 commenced production during fourth quarter 2015. Additional wells are |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | | | | | expected to commence production in 2019 and 2020. The Fund expects to spend $2.6 million for additional development costs and $1.1 million for asset retirement obligations. |
| South Pelto 9 | 16.67% | $ | 5,026 | $ | 5,233 | South Pelto 9, a single-well project, commenced production in 2007. After various shut-ins in late-2015 and early-2016, due to third-party facilities' repair and maintenance activities, the well resumed production in late-April 2016. The Fund expects to spend $0.2 million for asset retirement obligations. |

**Sale of Investment in Delta House**

As of December 31, 2016, the Fund invested a total of $0.6 million in Delta House and has received cash from its investment totaling $0.6 million, of which $0.3 million relates to dividends received and $0.3 million relates to cash proceeds from the sale of approximately 74% of its investment, pursuant to a unit purchase agreement with D-Day Offshore Holdings, LLC dated October 31, 2016. Certain other funds managed by the Manager were also parties to this unit purchase agreement. The Fund adjusted the carrying value of its investment in Delta House in third quarter 2016 to fair value, which was determined based on the third party sale and recorded a loss on investment during the year ended December 31, 2016 of $0.1 million. The loss was included on the Fund's statement of operations within "Loss on investment in Delta House". Inputs used to estimate fair value of the investment in Delta House are categorized as Level 3 in the fair value hierarchy. As of December 31, 2016, the Fund's remaining carrying value for the investment in Delta House was $0.1 million.

**Marketing/Customers**

The Manager, on behalf of the Fund, markets the Fund's oil and natural gas to third parties consistent with industry practice. During 2015, Beta Sales and Transport, LLC ("Beta S&T") and DH Sales and Transport, LLC ("DH S&T"), wholly-owned subsidiaries of the Manager, were formed to act as aggregators to and as an accommodation for the Fund and other funds managed by the Manager to facilitate the transportation and sale of oil and natural gas produced from the Beta, Diller and Marmalard projects. During 2016, the Fund entered into master agreements with Beta S&T and DH S&T pursuant to which Beta S&T and DH S&T are obligated to purchase from the Fund all of its interests in oil and natural gas produced from the Beta, Diller and Marmalard projects and sell such volumes to unrelated third party purchasers. The number of customers purchasing the Fund's oil and natural gas may vary from time to time. Currently, and during 2016, the Fund had five major customers in the public market. Because a ready market exists for oil and natural gas, the Fund does not believe that the loss of any individual customer would have a material adverse effect on its financial position or results of operations. The Fund's current producing projects are near existing transportation infrastructure and pipelines. The Fund has one property, the Beta Project, for which it participated in the financing of platform and pipeline infrastructure.

The Fund's natural gas and oil generally is sold to its customers at prevailing market prices, which fluctuate with demand as a result of related industry variables. Historically, the markets for, and prices of, oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. This volatility is caused by numerous factors and market conditions that the Fund cannot control or influence; therefore, it is impossible to predict the future price of oil and natural gas with any certainty. During the year ended December 31, 2016, fluctuations in commodity prices had an adverse effect on the Fund's profitability and distributions. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report under the headings "Commodity Price Changes", "Results of Operations – Overview" and "Results of Operations – Oil and Gas Revenue" for information regarding the impact of prices on the Fund's oil and gas revenue. In the past, the Fund has entered, and in the future, may enter, into transactions, or derivative contracts, that fix the future prices or establish a price floor for portions of its oil or natural gas production.

**Seasonality**

Generally, the Fund's business operations are not subject to seasonal fluctuations in the demand for oil and natural gas that would result in more of the Fund's oil and natural gas being sold, or likely to be sold, during one or more particular months or seasons. Once a project is producing, the operator of the project extracts oil and natural gas reserves throughout the year. Once extracted, oil and natural gas can be sold at any time during the year.

The Fund's properties are located in the Gulf of Mexico; therefore, its operations and cash flows may be significantly impacted by hurricanes and other inclement weather. Such events may also have a detrimental impact on third-party pipelines and processing facilities, upon which the Fund relies to transport and process the oil and natural gas it produces. The National Hurricane Center defines hurricane season in the Gulf of Mexico as June through November. The Fund did not experience any significant damage, shut-ins, or production stoppages due to hurricane activity in 2016.

**Operators**

The projects in which the Fund has invested are operated and controlled by unaffiliated third-party entities acting as operators. The operators are responsible for drilling, administration and production activities for leases jointly owned by working interest owners and act on behalf of all working interest owners under the terms of the applicable joint operating agreement. In certain circumstances, operators will enter into agreements with independent third-party subcontractors and suppliers to provide the various services required for operating leases. Currently, the Fund's properties are operated by Arena Offshore, Fieldwood Energy LLC, LLOG Exploration Offshore, L.L.C., Walter Oil & Gas Corporation and W&T Offshore, Inc.

Because the Fund does not operate any of the projects in which it has acquired a working interest, shareholders not only had to bear the risk that the Manager would find suitable projects, but also that, once selected, have to bear the risk that such projects will be managed prudently, efficiently and fairly by the operators.

**Insurance**

The Manager has obtained what it believes to be adequate insurance for the funds that it manages to cover the risks associated with the funds' passive investments, including those of the Fund. Although the Fund is not an operator, the Manager has, nonetheless, obtained hazard, property, general liability and other insurance in commercially reasonable amounts to cover its projects, as well as general liability, directors' and officers' liability and similar coverage for its business operations. However, there is no assurance that such insurance will be adequate to protect the Fund from material losses related to its projects. In addition, the Manager's practice is to obtain insurance as a package that is intended to cover most, if not all, of the funds under its management. The Manager re-evaluates its insurance coverage on an annual basis. While the Manager believes it has obtained adequate insurance in accordance with customary industry practices, the possibility exists, depending on the extent of the insurable incident, that insurance coverage may not be sufficient to cover all losses. In addition, depending on the extent, nature and payment of any claims to the Fund or to its affiliates, yearly insurance coverage limits may be exhausted and become insufficient to cover a claim made by the Fund in a given year.

**Salvage Fund**

The Fund deposits in a separate interest-bearing account, or salvage fund, cash to provide for its proportionate share of the anticipated cost of dismantling production platforms and facilities, plugging and abandoning the wells, and removing the platforms, facilities and wells in respect of the projects after the end of their useful lives in accordance with applicable federal and state laws and regulations. As of December 31, 2016, the Fund has $2.4 million invested in a salvage fund. On a monthly basis, the Fund expects to contribute to the salvage fund a portion of the operating income from the Beta, Diller and Marmalard projects, to fund the asset retirement obligations of such projects. Such contributions to the salvage fund will reduce the amount of cash distributions that would be made to investors by the Fund. Any portion of the salvage fund that remains after the Fund has paid for all of its asset retirement obligations will be distributed to the shareholders and the Manager. There are no restrictions on withdrawals from the salvage fund.

**Competition**

Competition exists in the acquisition of oil and natural gas leases and in all sectors of the oil and natural gas exploration and production industry. The Fund, through its Manager, has competed with other companies for the acquisition of leases as well as percentage ownership interests in oil and natural gas working interests in the secondary market. The Fund does not anticipate the acquisition of any additional ownership interests in oil and natural gas working interests as its capital has been fully allocated to current and past projects.

**Employees**

The Fund has no employees. The Manager operates and manages the Fund.

**Offices**

The administrative office of both the Fund and the Manager is located at 14 Philips Parkway, Montvale, NJ 07645, and their phone number is 800-942-5550. The Manager leases additional office space at 1254 Enclave Parkway, Houston, TX 77077 and 125 Worth Avenue, Suite 318, Palm Beach, Florida, 33480. In addition, the Manager maintains leases for other offices that are used for administrative purposes for the Fund and other funds managed by the Manager.

**Regulation**

Oil and natural gas exploration, development, production and transportation activities are subject to extensive federal and state laws and regulations. Regulations governing exploration and development activities require, among other things, the Fund's operators to obtain permits to drill projects and to meet bonding, insurance and environmental requirements in order to drill, own or operate projects. In addition, the location of projects, the method of drilling and casing projects, the restoration of properties upon which projects are drilled, and the plugging and abandoning of projects are also subject to regulations. The Fund owns projects that are located in the offshore waters of the Gulf of Mexico on the OCS. The Fund's operations and activities are therefore governed by the OCSLA and certain other laws and regulations.

***Outer Continental Shelf Lands Act***

Under the OCSLA, the United States federal government has jurisdiction over oil and natural gas development on the OCS. As a result, the United States Secretary of the Interior is empowered to sell exploration, development and production leases of a defined submerged area of the OCS, or a block, through a competitive bidding process. Such activity is conducted by the BOEM. Federal offshore leases are managed both by the BOEM and the Bureau of Safety and Environmental Enforcement ("BSEE") pursuant to regulations promulgated under the OCSLA. The OCSLA authorizes regulations relating to safety and environmental protection applicable to lessees and permittees operating on the OCS. Specific design and operational standards may apply to OCS vessels, rigs, platforms, vehicles and structures. BSEE regulates the design and operation of well control and other equipment at offshore production sites, implementation of safety and environmental management systems, and mandatory third-party compliance audits, among other requirements. BSEE adopted strict requirements for subsea drilling production equipment and had proposed new requirements to implement equipment reliability improvements, building upon enhanced industry standards for blowout preventers and blowout prevention technologies, and reforms in well design, well control, casing, cementing, real-time well monitoring and subsea containment. In April 2016, BSEE adopted a final rule establishing updated standards for blowout prevention systems and other well controls pertaining to offshore activities. The final rule became effective July 28, 2016; compliance with certain provisions of the final rule, however, are deferred as specified. The final rule imposes new requirements relating to, among, other things, well design, well control, casing, cementing, real-time well monitoring and subsea containment. BSEE has also published a policy statement on safety culture with nine characteristics of a robust safety culture. The rule applies directly to operators as opposed to non-operators. However, the costs associated with compliance, which at this time cannot be determined or estimated, will likely increase the costs of operating in the Gulf of Mexico and such costs will be imposed upon all working interest owners, including the Fund. Violations of environmentally related lease conditions or regulations issued pursuant to the OCSLA can result in substantial civil and criminal penalties as well as potential court injunctions curtailing operations and the cancellation of leases. Such enforcement liabilities, delay or restriction of activities can result from either governmental or citizen prosecution.

***BOEM Notice to Lessees on Supplemental Bonding***

On July 14, 2016, the BOEM issued a Notice to Lessees ("NTL") that discontinued and materially replaced existing policies and procedures regarding financial security (i.e. supplemental bonding) for decommissioning obligations of lessees of federal oil and gas leases and owners of pipeline rights-of-way, rights-of use and easements on the OCS ("Lessees"). Generally, the new NTL (i) ended the practice of excusing Lessees from providing such additional security where co-lessees had sufficient financial strength to meet such decommissioning obligations, (ii) established new criteria for determining financial strength and additional security requirements of such Lessees, (iii) provided acceptable forms of such additional security and (iv) replaced the waiver system with one of self-insurance. The new rule became effective as of September 12, 2016; however on January 6, 2017, the BOEM announced that it was suspending the implementation timeline for six months in certain circumstances. The Fund, as well as other industry participants, are working with the BOEM, its operators and working interest partners to determine and agree upon the correct level of decommissioning obligations to which they may be liable and the manner in which such obligations will be secured. The impact of the NTL, if enforced without change or amendment, may require the Fund to fully secure all of its potential abandonment liabilities to the BOEM satisfaction using one or more of the enumerated methods for doing so. Potentially this could increase costs to the Fund if the Fund is required to obtain additional supplemental bonding, fund escrow accounts or obtain letters of credit.

***Sales and Transportation of Oil and Natural Gas***

The Fund, directly or indirectly through affiliated entities, sells its proportionate share of oil and natural gas to the market and receives market prices from such sales. These sales are not currently subject to regulation by any federal or state agency. However, in order for the Fund to make such sales, it is dependent upon unaffiliated pipeline companies whose rates, terms and conditions of transport are subject to regulation by the Federal Energy Regulatory Commission. Generally, depending on certain factors, pipelines can charge rates that are either market-based or cost-of-service-based. In some circumstances, rates can be agreed upon pursuant to settlement. Thus, the rates that pipelines charge the Fund, although regulated, are beyond the Fund's control. Nevertheless, such rates would apply uniformly to all transporters on that pipeline and, as a result, management does not anticipate that the impact to the Fund of any changes in such rates, terms or conditions would be materially different than the impact upon other oil or natural gas producers and marketers.

***Environmental Matters and Regulation***

The Fund's operations are subject to pervasive environmental laws and regulations governing the discharge of materials into the air and water, the handling and managing of waste materials, and the protection of aquatic species and habitats. While most of the activities to which these federal, state and local environmental laws and regulations apply are conducted by the operators on the Fund's behalf, the Fund shares the liability along with its other working interest owners for any environmental damage. The environmental laws and regulations to which its operations are subject may require the Fund, or the operator, to acquire permits to commence drilling operations, restrict or prohibit the release of certain materials or substances into the environment, impose the installation of certain environmental control devices, require certain remedial measures to prevent pollution and other discharges such as the plugging of abandoned projects and, finally, impose in some instances severe penalties, fines and liabilities for the environmental damage that may be caused by the Fund's projects.

Some of the environmental laws that apply to oil and natural gas exploration and production are described below:

***Oil Pollution Act.*** The Oil Pollution Act of 1990, as amended (the "OPA"), amends Section 311 of the Federal Water Pollution Control Act of 1972, as amended (the "Clean Water Act") and was enacted in response to the numerous tanker spills, including the Exxon Valdez spill, that occurred in the 1980s. Among other things, the OPA clarifies the federal response authority to, and increases penalties for, such spills. OPA imposes strict, joint and several liabilities on "responsible parties" for damages, including natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility and the lessee or permit holder of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities and deepwater ports of $633.85 million, while the liability limit for a responsible party for offshore facilities, including any offshore pipeline, is equal to all removal costs plus up to $133.65 million in other damages for each incident. These liability limits may not apply if a spill is caused by a party's gross negligence or willful misconduct, if the spill resulted from violation of a federal safety, construction or operating regulation, or if a party fails to report a spill or to cooperate fully in a clean-up. Regulations under the OPA require owners and operators of rigs in United States waters to maintain certain levels of financial responsibility. The failure to comply with the OPA's requirements may subject a responsible party to civil, criminal, or administrative enforcement actions. The Fund is not aware of any action or event that would subject us to liability under the OPA. Compliance with the OPA's financial assurance and other operating requirements has not had, and the Fund believes will not in the future have, a material impact on the Fund's operations or financial condition.

***Clean Water Act.*** Generally, the Clean Water Act imposes liability for the unauthorized discharge of pollutants, including petroleum products, into the surface and coastal U.S. waters, except in strict conformance with discharge permits issued by the federal, or state, if applicable, agency. Regulations governing water discharges also impose other requirements, such as the obligation to prepare spill response plans. The Fund's operators are responsible for compliance with the Clean Water Act, although the Fund may be liable for any failure of the operator to do so.

***Clean Air Act.*** The Federal Clean Air Act of 1970, as amended (the "Clean Air Act"), restricts the emission of certain air pollutants. Prior to constructing new facilities, permits may be required before work can commence and existing facilities may be required to incur additional capital costs to add equipment to ensure and maintain compliance. As a result, the Fund's operations may be required to incur additional costs to comply with the Clean Air Act.

***Other Environmental Laws***. In addition to the above, the Fund's operations may be subject to the ***Resource Conservation and Recovery Act of 1976****, as amended,* which regulates the generation, transportation, treatment, storage, disposal and cleanup of certain hazardous wastes, as well as the ***Comprehensive Environmental Response, Compensation, and Liability Act of 1980****, as amended,* which imposes joint and several liability without regard to fault or legality of conduct on classes of persons who are considered responsible for the release of a hazardous substance into the environment.

The above represents a brief outline of significant environmental laws that may apply to the Fund's operations. The Fund believes that its operators are in compliance with each of these environmental laws and the regulations promulgated thereunder. The Fund does not believe that its environmental, health and safety risks are materially different from those of comparable companies in the United States in the offshore oil and gas industry. However, there are no assurances that the environmental regulations described above will not result in curtailment of production; material increases in the costs of production, development or exploration; enforcement actions or other penalties as a result of any non-compliance with any such regulations; or otherwise have a material adverse effect on the Fund's operating results and cash flows.

***Dodd-Frank Act.*** The Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), among other provisions, establishes federal oversight and regulation of the over-the-counter derivatives market and entities that participate in that market and, in addition, requires certain additional SEC reporting requirements.

On February 3, 2017, the "Presidential Executive Order on Core Principles for Regulating the United States Financial System" (the "Order") was issued to review the Dodd-Frank Act. The Fund cannot predict at this time what regulations or portions of the law, if any, will be changed as a result of the Order.

Under its LLC Agreement, the Fund has the authority to utilize derivative instruments to manage the price risk attributable to its oil and gas production. Dodd-Frank Act mandates that many derivatives be executed in regulated markets and submitted for clearing to regulated clearinghouses. Derivatives will be subject to minimum daily margin requirements set by the relevant clearinghouse and, potentially, by the SEC or the U.S. Commodity Futures Trading Commission ("CFTC"), and derivatives dealers may demand the unilateral ability to increase margin requirements beyond any regulatory or clearinghouse minimums. In addition, as required by Dodd-Frank Act, the CFTC has set "speculative position limits" (which are limits imposed on the maximum net long or net short speculative positions that a person may hold or control with respect to futures or options contracts traded on the U.S. commodities exchange) with respect to most energy contracts. These requirements under Dodd-Frank Act could significantly increase the cost of any derivatives transactions of the Fund (including through requirements to post collateral, which could adversely affect the Fund's liquidity), materially alter the terms of derivatives transactions and make it more difficult for the Fund to enter into customized transactions, cause the Fund to liquidate certain positions it may hold, reduce the ability of the Fund to protect against price volatility and other risks by making certain hedging strategies impossible or so costly that they are not economical to implement, and increase the Fund's exposure to less creditworthy counterparties. If as a result of the legislation and regulations, the Fund alters any hedging program that may be in effect from time to time, the Fund's operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Fund's performance. The Fund is not currently, and has not been during 2016, or at any time since 2012, a party to any derivative instruments or hedging programs.

Dodd-Frank Act also required the SEC to issue rules requiring resource extraction issuers to disclose annually information relating to certain payments made by the issuer to the U.S. federal government or a foreign government for the purpose of the commercial development of oil, natural gas or minerals. Rules issued by the SEC in 2012 were subsequently vacated in federal court in 2013. On June 27, 2016, the SEC adopted resource extraction issuer payment disclosure rules pursuant to Section 1504 of the Dodd-Frank Act that will require resource extraction companies to publicly file with the SEC information about the type and total amount of payments made to a foreign government or to the U.S. federal government for each project related to the development of crude oil, natural gas or minerals, and the type and total amount of payments made to each government. However, on February 14, 2017, a bill passed by the United States Congress was signed eliminating the SEC resource extraction issuer payment disclosure rules. The SEC will have one year to issue replacement rules to implement Section 1504 of the Dodd-Frank Act.

## ITEM 1A. RISK FACTORS

Not required.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

## ITEM 2. PROPERTIES

The information regarding the Fund's properties that is contained in Item 1. "Business" of this Annual Report under the headings "Project Information" and "Properties," is incorporated herein by reference.

**Drilling Activity**

The following table sets forth the Fund's drilling activity during the years ended December 31, 2016 and 2015. Gross wells are the total number of wells in which the Fund has an interest. Net wells are the sum of the Fund's fractional working interests owned in the gross wells. All of the wells, which produce both oil and natural gas, are located in the offshore waters of the Gulf of Mexico. See Item 1. "Business" of this Annual Report under the heading "Properties" for more information about the well in-progress as of December 31, 2016.

| | 2016 | | 2015 | |
|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** |
| Exploratory wells: | | | | |
| Productive | 1 | 0.05 | 2 | 0.02 |
| In-progress | - | - | 1 | 0.05 |
| Exploratory well total | 1 | 0.05 | 3 | 0.07 |
| | | | | |
| Development wells: | | | | |
| Productive | 1 | 0.05 | 3 | 0.03 |
| In-progress | 1 | 0.05 | - | - |
| Development well total | 2 | 0.10 | 3 | 0.03 |

**Unaudited Oil and Gas Reserve Quantities**

The preparation of the Fund's oil and gas reserve estimates are completed in accordance with the Fund's internal control procedures over reserve estimation. The Fund's management controls over proved reserve estimation include: 1) verification of input data that is provided to an independent petroleum engineering firm; 2) engagement of well-qualified and independent reservoir engineers for preparation of reserve reports annually in accordance with SEC reserve estimation guidelines; and 3) a review of the reserve estimates by the Manager.

The Manager's primary technical person in charge of overseeing the Fund's reserve estimates has a B.S. degree in Petroleum Engineering and is a member of the Society of Petroleum Engineers, the Association of American Drilling Engineers and the American Petroleum Institute. With over thirty years of industry experience, he is currently responsible for reserve reporting, engineering and economic evaluation of exploration and development opportunities, and the oversight of drilling and production operations.

The Fund's reserve estimates as of December 31, 2016 and 2015 were prepared by Netherland, Sewell & Associates, Inc. ("NSAI"), an independent petroleum engineering firm. The information regarding the qualifications of the petroleum engineer is included within the report from NSAI, which is filed as Exhibit 99.1 to this Annual Report, and is incorporated herein by reference.

*Proved Reserves*. Proved oil and gas reserves are estimated quantities of oil and natural gas, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The information regarding the Fund's proved reserves, which is contained in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report under the heading "Critical Accounting Estimates – Proved Reserves", is incorporated herein by reference. The information regarding the Fund's unaudited net quantities of proved developed and undeveloped reserves, which is contained in Table III in the "Supplementary Financial Information – Information about Oil and Gas Producing Activities – Unaudited" included in Item 8. "Financial Statements and Supplementary Data" of this Annual Report, is incorporated herein by reference.

*Proved Undeveloped Reserves*. As of December 31, 2016, the Fund had proved undeveloped reserves related to the Beta and Marmalard projects totaling 0.2 million barrels of oil, 0.1 million barrels of natural gas liquid ("NGL") and 0.5 million mcf of natural gas. As of December 31, 2015, the Fund had proved undeveloped reserves related to the Beta and Marmalard projects totaling 0.9 million barrels of oil, 45 thousand barrels of NGL and 1.0 million mcf of natural gas. The Beta and Marmalard projects were determined to be discoveries in 2012. The Beta Project commenced production in third quarter 2016 and the Marmalard Project commenced production in 2015.

During the year ended December 31, 2016, the Fund incurred costs to advance the development of its proved undeveloped reserves of approximately $7.0 million, which related to the Beta Project. The Fund currently expects to develop the proved undeveloped reserves relating to the Beta and Marmalard projects over the next several years. Information regarding estimated future development costs relating to the Beta and Marmalard projects, which is contained in Item 1. "Business" of this Annual Report under the heading "Properties", is incorporated herein by reference. Estimated future development costs include capital spending on major development projects, some of which will take several years to complete. Proved undeveloped reserves related to major development projects will be reclassified to proved developed reserves when production commences.

**Production and Prices**

The information regarding the Fund's production of oil and natural gas, and certain price and cost information during the years ended December 31, 2016 and 2015 that is contained in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report under the headings "Results of Operations – Overview" and "Results of Operations – Operating Expenses" is incorporated herein by reference.

**Delivery Commitments**

As of December 31, 2016, the Fund had no delivery obligations or delivery commitments under any existing contracts.

## ITEM 3. LEGAL PROCEEDINGS

None.

## ITEM 4. MINE SAFETY DISCLOSURES

None.

## PART II

### ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

There is currently no established public trading market for the Shares. As of January 31, 2017, there were 1,688 shareholders of record of the Fund.

Distributions are made in accordance with the provisions of the LLC Agreement. At various times throughout the year, the Manager determines whether there is sufficient available cash, as defined in the LLC Agreement, for distribution to shareholders. Due to the significant capital required to develop the Beta, Diller and Marmalard projects, distributions have been impacted, and will be impacted in the future, by amounts reserved to provide for their ongoing development costs, debt service costs, and funding of their estimated asset retirement obligations. There is no requirement to distribute available cash and, as such, available cash is distributed to the extent and at such times as the Manager believes is advisable. The Fund did not pay distributions during the year ended December 31, 2016. During the year ended December 31, 2015, the Fund paid distributions totaling $0.2 million.

### ITEM 6. SELECTED FINANCIAL DATA

Not required.

### ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

**Overview of the Fund's Business**

The Fund was organized primarily to acquire interests in oil and gas properties located in the United States offshore waters of Texas, Louisiana and Alabama in the Gulf of Mexico. The Fund's primary investment objective is to generate cash flow for distribution to its shareholders by generating returns across a portfolio of exploratory or development oil and natural gas projects. Distributions to shareholders are made in accordance with the Fund's LLC Agreement. The Fund does not expect in the future to investigate or invest in any additional projects other than those in which it currently has a working interest. The Fund's remaining capital has been fully allocated to complete such projects.

The Manager performs, or arranges for the performance of, the management, advisory and administrative services required for Fund operations. The Fund does not currently, nor is there any plan to, operate any project in which the Fund participates. The Manager enters into operating agreements with third-party operators for the management of all exploration, development and producing operations, as appropriate. See Item 1. "Business" of this Annual Report under the headings "Project Information" and "Properties" for more information regarding the projects of the Fund.

**Commodity Price Changes**

Changes in commodity prices may significantly affect liquidity and expected operating results. Reductions in oil and gas prices not only reduce revenues and profits, but could also reduce the quantities of reserves that are commercially recoverable. Significant declines in prices could result in non-cash charges to earnings due to impairment.

During fourth quarter 2014, there was a significant decline in oil and natural gas commodity prices, which continued into mid-year 2016 when oil and gas commodity prices began to show improvement. The Fund plans for price cyclicality in its planning and believes it is well positioned to withstand such price volatility. Despite operating in a sustained lower commodity price environment, the Fund continued to advance the development of the Beta Project and during the second half of 2016, two wells from the Beta Project commenced production. The Fund has suspended distributions and continues to conserve cash to complete the final phase of the Beta Project as budgeted. See "Results of Operations" under this Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" for more information on the average oil and natural gas prices received by the Fund during the years ended December 31, 2016 and 2015 and the effect of such decreased average prices on the Fund's results of operations. If oil and natural gas prices decline, even if only for a short period of time, the Fund's results of operations and liquidity will continue to be adversely impacted.

Market pricing for oil and natural gas is volatile, and is likely to continue to be volatile in the future. This volatility is caused by numerous factors and market conditions that the Fund cannot control or influence. Therefore, it is impossible to predict the future price of oil and natural gas with any certainty. Factors affecting market pricing for oil and natural gas include:

- weather conditions;
- economic conditions, including demand for petroleum-based products;
- actions by OPEC, the Organization of Petroleum Exporting Countries;
- political instability in the Middle East and other major oil and gas producing regions;
- governmental regulations, both domestic and foreign;
- domestic and foreign tax policy;
- the pace adopted by foreign governments for the exploration, development, and production of their national reserves;
- the supply and price of foreign oil and gas;
- the cost of exploring for, producing and delivering oil and gas;
- the discovery rate of new oil and gas reserves;
- the rate of decline of existing and new oil and gas reserves;
- available pipeline and other oil and gas transportation capacity;
- the ability of oil and gas companies to raise capital;
- the overall supply and demand for oil and gas; and
- the price and availability of alternate fuel sources.

**Critical Accounting Estimates**

The discussion and analysis of the Fund's financial condition and results of operations are based upon the Fund's financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). In preparing these financial statements, the Fund is required to make certain estimates, judgments and assumptions. These estimates, judgments and assumptions affect the reported amounts of the Fund's assets and liabilities, including the disclosure of contingent assets and liabilities, at the date of the financial statements and the reported amounts of its revenues and expenses during the periods presented. The Fund evaluates these estimates and assumptions on an ongoing basis. The Fund bases its estimates and assumptions on historical experience and on various other factors that the Fund believes to be reasonable at the time the estimates and assumptions are made. However, future events and actual results may differ from these estimates and assumptions and such differences may have a material impact on the results of operations, financial position or cash flows. See Note 1 of "Notes to Financial Statements" – "Organization and Summary of Significant Accounting Policies" contained in Item 8. "Financial Statements and Supplementary Data" within this Annual Report for a discussion of the Fund's significant accounting policies. The following is a discussion of the accounting policies and estimates that management believes are most significant.

***Accounting for Acquisition, Exploration and Development Costs***

Acquisition, exploration and development costs are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and natural gas leasehold acreage, including lease bonuses, brokers' fees and other related costs, are capitalized. Costs of drilling and equipping productive wells and related production facilities are capitalized. Annual lease rentals and exploration expenses are expensed as incurred.

***Proved Reserves***

Estimates of proved reserves are key components of the Fund's most significant financial estimates involving its rate for recording depletion and amortization. Annually, the Fund engages an independent petroleum engineer to perform a comprehensive study of the Fund's proved properties to determine the quantities of reserves and the period over which such reserves will be recoverable. The Fund's estimates of proved reserves are based on the quantities of oil and natural gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under existing economic and operating conditions. However, there are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production and timing of development expenditures, including many factors beyond the Fund's control. The estimation process is very complex and relies on assumptions and subjective interpretations of available geologic, geophysical, engineering and production data and the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geological interpretation and judgment. In addition, as a result of volatility and changing market conditions, commodity prices and future development costs will change from period to period, causing estimates of proved reserves and future net revenues to change.

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***Asset Retirement Obligations***
Asset retirement obligations include costs to plug and abandon the Fund's wells and to dismantle and relocate or dispose of the Fund's production platforms and related structures and restoration costs of land and seabed. The Fund develops estimates of these costs based upon the type of production structure, water depth, reservoir depth and characteristics, ongoing discussions with the wells' operators and, at times, with information provided by third-party abandonment consultants specializing in the oil and gas industry. Because these costs typically extend many years into the future, estimating these future costs is difficult and requires significant judgment that is subject to future revisions based upon numerous factors such as the timing of settlements, the credit-adjusted risk-free rates used and inflation rates, including changing technology and the political and regulatory environment. Estimates are reviewed on a bi-annual basis, or more frequently if an event occurs that would dictate a change in assumptions or estimates.

***Impairment of Long-Lived Assets***
The Fund reviews the carrying value of its oil and gas properties annually and when management determines that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments are determined by comparing estimated future net undiscounted cash flows to the carrying value at the time of the review. If the carrying value exceeds estimated future net undiscounted cash flows, the carrying value of the asset is written down to fair value, which is determined using estimated future net discounted cash flows from the asset. The fair value determinations require considerable judgment and are sensitive to change. Different pricing assumptions, reserve estimates or discount rates could result in a different calculated impairment. Given the volatility of oil and natural gas prices, it is reasonably possible that the Fund's estimate of net discounted future cash flows from proved oil and natural gas reserves could change in the near term.

Significant and consistent fluctuations in oil and natural gas prices since fourth quarter 2014 have resulted in impairments of oil and gas properties as described below in this Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations" of this Annual Report under the heading "Results of Operations - Impairment of Oil and Gas Properties". If oil and natural gas prices decline, even if only for a short period of time, it is possible that additional impairments of oil and gas properties will occur.

**Results of Operations**

The following table summarizes the Fund's results of operations during the years ended December 31, 2016 and 2015, and should be read in conjunction with the Fund's financial statements and the notes thereto included within Item 8. "Financial Statements and Supplementary Data" in this Annual Report.

| | Year ended December 31, 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| **Revenue** | | |
| Oil and gas revenue | $ 6,721 | $ 3,952 |
| **Expenses** | | |
| Depletion and amortization | 3,923 | 1,668 |
| Impairment of oil and gas properties | 13 | 266 |
| Management fees to affiliate | 1,282 | 1,399 |
| Operating expenses | 3,735 | 2,506 |
| General and administrative expenses | 186 | 160 |
| Total expenses | 9,139 | 5,999 |
| Loss from operations | (2,418) | (2,047) |
| **Other (loss) income** | | |
| Loss on investment in Delta House | (114) | - |
| Dividend income | 191 | 75 |
| Interest (expense) income, net | (1,187) | 7 |
| Total other (loss) income | (1,110) | 82 |
| Net loss | $ (3,528) | $ (1,965) |

***Overview.*** The following table provides information related to the Fund's oil and gas production and oil and gas revenue during the years ended December 31, 2016 and 2015. NGL sales are included within gas sales.

| | Year ended December 31, | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| Number of wells producing | | 12 | | 10 |
| Total number of production days | | 2,807 | | 1,785 |
| Oil sales (in thousands of barrels) | | 142 | | 69 |
| Average oil price per barrel | $ | 41 | $ | 47 |
| Gas sales (in thousands of mcfs) | | 361 | | 275 |
| Average gas price per mcf | $ | 2.45 | $ | 2.47 |

The increases noted in the above table were primarily related to the commencement of production of the Beta, Marmalard and Diller projects, partially offset by the Liberty Project, which had been shut-in during the early part of 2016. See Item 1. “Business” of this Annual Report under the heading “Properties” for more information.

***Oil and Gas Revenue***. Generally, the Fund sells oil, gas and NGLs under two types of agreements, which are common in the oil and gas industry. In a netback agreement, the Fund receives a price, net of transportation expense incurred by the purchaser, and the Fund records revenue at the net price received. In the second type of agreement, the Fund pays transportation expense directly, and transportation expense is included within operating expense in the statements of operations.

Oil and gas revenue during the year ended December 31, 2016 was $6.7 million, an increase of $2.8 million from the year ended December 31, 2015. The increase was attributable to increased sales volume totaling $3.7 million, partially offset by decreased oil and gas prices totaling $0.9 million.

See “Overview” above for factors that impact the oil and gas revenue volume and rate variances.

***Depletion and Amortization.*** Depletion and amortization during the year ended December 31, 2016 was $3.9 million, an increase of $2.3 million from the year ended December 31, 2015. The increase was attributable to an increase in the average depletion rate totaling $1.3 million coupled with an increase in production volumes totaling $1.1 million, partially offset by adjustments to asset retirement obligations related to fully depleted properties totaling $0.2 million, which were recorded in second quarter 2015. The increase in the average depletion rate was primarily attributable to the onset of production of the Beta Project. Depletion and amortization rates were also impacted by changes in reserve estimates provided annually by the Fund’s independent petroleum engineers.

See “Overview” above for certain factors that impact the depletion and amortization volume and rate variances.

***Impairment of Oil and Gas Properties.*** During the year ended December 31, 2016, the Fund recorded impairments of oil and gas properties of $13 thousand, related to Eugene Island 346/347, which was primarily attributable to declines in future oil and gas prices. During the year ended December 31, 2015, the Fund recorded impairments of oil and gas properties of $0.3 million, related to Eugene Island 346/347 and the Cobalt Project, which were attributable to both declines in future oil and gas prices and revisions to reserve estimates as provided by the Fund’s independent petroleum engineers.

***Management Fees to Affiliate***. An annual management fee, totaling 2.5% of total capital contributions, net of cumulative dry-hole and related well costs incurred by the Fund, is paid monthly to the Manager. Such fee may be temporarily waived by the Manager to accommodate the Fund’s short-term capital commitments.

***Operating Expenses***. Operating expenses represent costs specifically identifiable or allocable to the Fund’s wells, as detailed in the following table.

| | Year ended December 31, | | | |
|---|---|---|---|---|
| | 2016 | | 2015 | |
| | (in thousands) | | | |
| Lease operating expense | $ | 2,764 | $ | 1,854 |
| Transportation expense | | 328 | | 153 |
| Insurance expense | | 306 | | 351 |
| Accretion expense | | 154 | | 94 |
| Workover expense | | 138 | | 34 |
| Other | | 45 | | 20 |

| | | |
|---|---|---|
| | $ 3,735 | $ 2,506 |

Lease operating expense and transportation expense relates to the Fund's producing properties. Insurance expense represents premiums related to the Fund's properties, which vary depending upon the number of wells producing or drilling. Accretion expense relates to the asset retirement obligations established for the Fund's proved properties. Workover expense represents costs to restore or stimulate production of existing reserves. During the year ended December 31, 2016, workover expense primarily relates to the Diller and Marmalard projects.

The average production cost, which includes lease operating expense, transportation expense and insurance expense, was $16.81 per barrel of oil equivalent ("BOE") during the year ended December 31, 2016, compared to $20.59 per BOE during the year ended December 31, 2015. The decrease was primarily attributable to the Marmalard Project, which had higher cost per BOE in 2015 as a result of costs associated with the project's onset of production coupled with costs incurred by the Beta Project during 2015 prior to its commencement of production.

***General and Administrative Expenses***. General and administrative expenses represent costs specifically identifiable or allocable to the Fund, such as accounting and professional fees and insurance expenses.

***Loss on Investment in Delta House.*** During the year ended December 31, 2016, the Fund recognized a loss on investment of $0.1 million related to its investment in Delta House. There were no such amounts recorded during the year ended December 31, 2015. See Note 1 of "Notes to Financial Statements" - "Organization and Summary of Significant Accounting Policies" contained in Item 8. "Financial Statements and Supplementary Data" within this Annual Report for more information regarding the Investment in Delta House.

***Dividend Income.*** Dividend income is related to the Fund's investment in Delta House. See Note 1 of "Notes to Financial Statements" - "Organization and Summary of Significant Accounting Policies" contained in Item 8. "Financial Statements and Supplementary Data" within this Annual Report for more information regarding the Investment in Delta House.

***Interest (Expense) Income, Net***. Interest (expense) income, net is comprised of interest expense and amortization of debt discounts and deferred financing costs related to the Fund's long-term borrowings (see "Liquidity Needs" below for additional information), and interest income earned on cash and cash equivalents and salvage fund.

**Capital Resources and Liquidity**

***Operating Cash Flows***
Cash flows provided by operating activities during the year ended December 31, 2016 were $0.9 million, related to revenue received of $5.8 million and dividend income received of $0.2 million, partially offset by operating expenses of $3.7 million, management fees of $1.3 million and general and administrative expenses of $0.2 million.

Cash flows provided by operating activities during the year ended December 31, 2015 were $0.2 million, related to revenue received of $3.8 million and dividend income received of $0.1 million, partially offset by operating expenses of $2.2 million, management fees of $1.4 million and general and administrative expenses of $0.1 million.

***Investing Cash Flows***
Cash flows used in investing activities during the year ended December 31, 2016 were $5.6 million, related to capital expenditures for oil and gas properties of $5.5 million and investments in salvage fund of $0.4 million, partially offset by proceeds from the sale of investment in Delta House of $0.3 million.

Cash flows used in investing activities during the year ended December 31, 2015 were $14.3 million, related to capital expenditures for oil and gas properties and investment in Delta House of $14.0 million and investments in salvage fund of $0.3 million.

***Financing Cash Flows***
Cash flows provided by financing activities during the year ended December 31, 2016 were $1.3 million, related to proceeds from long-term borrowings.

Cash flows provided by financing activities during the year ended December 31, 2015 were $16.0 million, related to proceeds from long-term borrowings of $16.2 million, partially offset by manager and shareholder distributions totaling $0.2 million.

**Estimated Capital Expenditures**

The Fund has entered into multiple agreements for the acquisition, drilling and development of its oil and gas properties. The estimated capital expenditures associated with these agreements vary depending on the stage of development on a property-by-property basis. See Item 1. "Business" of this Annual Report under the heading "Properties" and "Liquidity Needs" below for additional information.

Capital expenditures for oil and gas properties have been funded with the capital raised by the Fund in its private placement offering, and in certain circumstances, through debt financing. The number of projects in which the Fund could invest was limited, and each unsuccessful project the Fund experienced exhausted its capital and reduced its ability to generate revenue.

**Liquidity Needs**

The Fund's primary short-term liquidity needs are to fund its operations, capital expenditures for its oil and gas properties and borrowing repayments. Such needs are funded utilizing operating income and existing cash on-hand.

As of December 31, 2016, the Fund's estimated capital commitments related to its oil and gas properties were $15.7 million (which include asset retirement obligations for the Fund's projects of $5.9 million), of which $5.5 million is expected to be spent during the year ending December 31, 2017, which is primarily related to complete the final phase of the Beta Project. As a result of the continued development of the Beta Project, the Fund has experienced negative cash flows for year ended December 31, 2016. Additionally, current liabilities exceeded current assets as of December 31, 2016. Future results of operations and cash flows are dependent on the continued successful development and the related production of oil and gas revenues from the Beta Project. Based upon its current cash position and its current reserve estimates, the Fund expects cash flow from operations to be sufficient to cover its commitments, borrowing repayments, as well as ongoing operations. Reserve estimates are projections based on engineering data that cannot be measured with precision, require substantial judgment, and are subject to frequent revision. However, if cash flow from operations is not sufficient to meet the Fund's capital commitments, the Manager will temporarily waive all or a portion of the management fee as well as provide short-term financing to accommodate the Fund's short-term capital commitments if needed.

The Manager is entitled to receive an annual management fee from the Fund regardless of the Fund's profitability in that year. However, pursuant to the terms of the LLC Agreement, the Manager is also permitted to waive the management fee at its own discretion. Such fee may be temporarily waived to accommodate the Fund's short-term capital commitments.

Distributions, if any, are funded from available cash from operations, as defined in the LLC Agreement, and the frequency and amount are within the Manager's discretion. Due to the significant capital required to develop the Beta, Diller and Marmalard projects, distributions have been impacted, and will be impacted in the future, by amounts reserved to provide for their ongoing development costs, debt service costs, and funding their estimated asset retirement obligations.

*Credit Agreement*
In November 2012, the Fund entered into a credit agreement (as amended on September 30, 2016, the "Credit Agreement") with Rahr Energy Investments LLC, as administrative agent and lender (and any other banks or financial institutions that may in the future become a party thereto), that provides for an aggregate loan commitment to the Fund of approximately $24.1 million to provide capital toward the funding of the Fund's share of development costs on the Beta Project. As of December 31, 2016 and 2015, the Fund had borrowed $24.1 million and $22.8 million, respectively, under the Credit Agreement wherein no borrowings remain.

The loan bears interest at 8% compounded annually. Principal and interest are repaid at the lesser of (i) a monthly rate of 1.25% of the Fund's total principal outstanding as of July 31, 2016 for the first seven months beginning October 2016, and increases to a monthly rate of 4.5% thereafter until the loan is repaid in full, and (ii) debt service amount as defined in the Credit Agreement, in no event later than December 31, 2020. The loan may be prepaid by the Fund without premium or penalty.

As additional consideration to the lenders, the Fund has agreed to convey an overriding royalty interest ("ORRI") in its working interest in the Beta Project to the lenders. The Fund's share of the lender's aggregate ORRI is directly proportionate to its level of borrowing as a percentage of total borrowings of all the other participating funds managed by the Manager. Such ORRI will not accrue or become payable to the Lenders until after the Loan is repaid in full.

Unamortized debt discounts and deferred financing costs of $0.4 million as of December 31, 2016 and $0.7 million as of December 31, 2015 are presented as a reduction of "Long-term borrowings" on the balance sheets.

Principal and interest amounts are contracted to be repaid beginning October 2016, over a period not to extend beyond December 31, 2020. The Fund expects operating income from the Beta Project will be sufficient to cover the principal and interest payments required under the Credit Agreement. See Note 3 of "Notes to Financial Statements" – "Credit Agreement – Beta Project Financing" contained in Item 8. "Financial Statements and Supplementary Data" within this Annual Report for more information regarding the Credit Agreement.

The Credit Agreement contains customary negative covenants including covenants that limit the Fund's ability to, among other things, grant liens, change the nature of its business, or merge into or consolidate with other persons. The events which constitute events of default are also customary for credit facilities of this nature and include payment defaults, breaches of representations, warrants and covenants, insolvency and change of control. Upon the occurrence of a default, in some cases following a notice and cure period, the lenders under the Credit Agreement may accelerate the maturity of the loan and require full and immediate repayment of all borrowings under the Credit Agreement. The Fund believes it is in compliance with all covenants under the Credit Agreement as of December 31, 2016 and 2015.

**Off-Balance Sheet Arrangements**

The Fund had no off-balance sheet arrangements as of December 31, 2016 and 2015 and does not anticipate the use of such arrangements in the future.

**Contractual Obligations**

The Fund enters into participation and joint operating agreements with operators. On behalf of the Fund, an operator enters into various contractual commitments pertaining to exploration, development and production activities. The Fund does not negotiate such contracts. No contractual obligations exist as of December 31, 2016 and 2015, other than those discussed in "Estimated Capital Expenditures" and "Liquidity Needs – Credit Agreement" above.

**Recent Accounting Pronouncements**

See Note 1 of "Notes to Financial Statements" – "Organization and Summary of Significant Accounting Policies" contained in Item 8. "Financial Statements and Supplementary Data" within this Annual Report for a discussion of the Fund's recent accounting pronouncements.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Not required.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

All financial statements meeting the requirements of Regulation S-X and the supplementary financial information required by Item 302 of Regulation S-K are included in the financial statements listed in Item 15. "Exhibits and Financial Statement Schedules" and filed as part of this report.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

***Disclosure Controls and Procedures***

Under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer of the Fund, management of the Fund and the Manager carried out an evaluation of the effectiveness of the design and operation of the Fund's disclosure controls and procedures as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as of December 31, 2016. Based upon the evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Fund's disclosure controls and procedures are effective as of the end of the period covered by this report.

***Management's Report on Internal Control over Financial Reporting***

Management of the Fund is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f)). The Fund's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management of the Fund, including its Chief Executive Officer and Chief Financial Officer, assessed the effectiveness of the Fund's internal control over financial reporting as of December 31, 2016. In making this assessment, management of the Fund used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (the "COSO") in *Internal Control — Integrated Framework (2013).* Based on their assessment using those criteria, management of the Fund concluded that, as of December 31, 2016, the Fund's internal control over financial reporting is effective.

This Annual Report does not include an attestation report of the Fund's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the Fund's registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the Fund to provide only management's report in this Annual Report.

***Changes in Internal Control over Financial Reporting***

The Chief Executive Officer and Chief Financial Officer of the Fund have concluded that there have not been any changes in the Fund's internal control over financial reporting during the quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, the Fund's internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The Fund has engaged Ridgewood Energy as the Manager. The Manager has very broad authority, including the authority to appoint the executive officers of the Fund. Executive officers of the Fund and their ages as of December 31, 2016 are as follows:

**Name, Age and Position with Registrant**

| |
|---|
| Robert E. Swanson, 69<br>Chief Executive Officer |
| Kenneth W. Lang, 62<br>President and Chief Operating Officer |
| Kathleen P. McSherry, 51<br>Executive Vice President and Chief Financial Officer |
| Robert L. Gold, 58<br>Executive Vice President |
| Daniel V. Gulino, 56<br>Senior Vice President, General Counsel and Secretary |

The officers in the above table have been officers of the Fund since December 21, 2004, the date of inception of the Fund, with the exception of Mr. Lang, who has been an officer of the Fund since June 2009. The officers are employed by and paid exclusively by the Manager. Set forth below is certain biographical information regarding the executive officers of Ridgewood Energy and the Fund:

**Robert E. Swanson** has served as the Chairman, Chief Executive Officer, and controlling shareholder of Ridgewood Energy since its inception and is the Chairman of the Investment Committee. Mr. Swanson is also the Chairman of Ridgewood Capital Management, LLC and Ridgewood Private Equity Partners, LLC, and President of Ridgewood Securities Corporation, affiliates of Ridgewood Energy. Mr. Swanson is an inactive member of the New York and New Jersey State Bars. He is a graduate of Amherst College and Fordham University Law School.

**Kenneth W. Lang** has served as the President and Chief Operating Officer of Ridgewood Energy since June 2009 and is a member of the Investment Committee. Prior to joining the Fund, Mr. Lang was with BP for twenty-four years, ultimately serving for his last two years with BP as Senior Vice President for BP's Gulf of Mexico business and a member of the Board of Directors for BP America, Inc. Prior to that, Mr. Lang was Vice President – Production for BP. After twenty-four years of service to BP, Mr. Lang retired and devoted fifteen months of personal time to pursue and explore other interests. Mr. Lang is a graduate of the University of Houston.

**Kathleen P. McSherry** has served as the Executive Vice President and Chief Financial Officer of Ridgewood Energy since 2001. Ms. McSherry holds a Bachelor of Science degree in Accounting from Kean University.

**Robert L. Gold** has served as a senior officer of Ridgewood Energy since 1987 and is a member of the Investment Committee. Mr. Gold has also served as the President and Chief Executive Officer of Ridgewood Capital since its inception in 1998. Mr. Gold is a member of the New York State Bar. Mr. Gold is a graduate of Colgate University and New York University School of Law.

**Daniel V. Gulino** is Senior Vice President - Legal Affairs and Secretary for Ridgewood Energy and has served in that capacity for Ridgewood Energy since 2003. Mr. Gulino also serves as Senior Vice President of Legal Affairs of Ridgewood Capital Management, LLC and Ridgewood Private Equity Partners, LLC and Senior Vice President & General Counsel of Ridgewood Securities Corporation. Mr. Gulino is a member of the New Jersey State and Pennsylvania State Bars. Mr. Gulino is a graduate of Fairleigh Dickinson University and Rutgers School of Law.

**Board of Directors and Board Committees**

The Fund does not have its own board of directors or any board committees. The Fund relies upon the Manager to provide recommendations regarding dispositions and financial disclosure. Officers of the Fund are not compensated by the Fund, and all compensation matters are addressed by the Manager, as described in Item 11. "Executive Compensation" of this Annual Report. Because the Fund does not maintain a board of directors and because officers of the Fund are compensated by the Manager, the Manager believes that it is appropriate for the Fund to not have a nominating or compensation committee.

**Code of Ethics**

The Manager has adopted a code of ethics for all employees, including the Manager's principal executive officer and principal financial and accounting officer. If any amendments are made to the code of ethics or the Manager grants any waiver, including any implicit waiver, from a provision of the code that applies to the Manager's executive officers or principal financial and accounting officer, the Fund will disclose the nature of such amendment or waiver on the Manager's website or in a current report on Form 8-K. Copies of the code of ethics are available, without charge, on the Manager's website at www.ridgewoodenergy.com and in print upon written request to the business address of the Manager at 14 Philips Parkway, Montvale, New Jersey 07645, ATTN: General Counsel.

**Section 16(a) Beneficial Ownership Reporting Compliance**
Section 16(a) of the Exchange Act, as amended, requires the Fund's executive officers and directors, and persons who own more than 10% of a registered class of the Fund's equity securities, to file reports of ownership and changes in ownership with the SEC. Based on a review of the copies of reports furnished or otherwise available to the Fund, the Fund believes that during the year ended December 31, 2016, all filing requirements applicable to its officers, directors and 10% beneficial owners were met on a timely basis.

**ITEM 11. EXECUTIVE COMPENSATION**

The executive officers of the Fund do not receive compensation from the Fund. The Manager and its affiliates compensate the officers without additional payments by the Fund. See Item 13. "Certain Relationships and Related Transactions, and Director Independence" of this Annual Report for more information regarding Manager compensation and payments to affiliated entities.

**ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS**

Beneficial ownership is determined in accordance with the rules of the SEC and includes voting or investment power with respect to the securities. Percentage of beneficial ownership is based on 870.6486 shares outstanding as of January 31, 2017. The following table sets forth information with respect to beneficial ownership of the Shares as of January 31, 2017 (no person owns more than 5% of the Shares). Except as indicated by footnote, and subject to applicable community property laws, the persons named in the table below have sole voting and investment power with respect to all shares shown as beneficially owned by them. Other than as indicated below, no officer of the Manager or the Fund owns any of the Shares.

| Name of beneficial owner | Number of shares | Percent |
|---|---|---|
| Robert E. Swanson, Chief Executive Officer | 2.0 | * |
| Executive officers as a group | 2.0 | * |

* Represents less than one percent.

**ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE**

Pursuant to the terms of the LLC Agreement, the Manager renders management, administrative and advisory services to the Fund. For such services, the Manager is paid an annual management fee, payable monthly, of 2.5% of total capital contributions, net of cumulative dry-hole and related well costs incurred by the Fund. Management fees during the years ended December 31, 2016 and 2015 were $1.3 million and $1.4 million, respectively.

The Manager is entitled to receive a 15% interest in cash distributions from operations made by the Fund. The Fund did not pay distributions during the year ended December 31, 2016. Distributions paid to the Manager during the year ended December 31, 2015 were $27 thousand.

None of the amounts paid to the Manager have been derived as a result of arm's length negotiations.

During 2015, Beta S&T and DH S&T, wholly-owned subsidiaries of the Manager, were formed to act as aggregators to and as an accommodation for the Fund and other funds managed by the Manager to facilitate the transportation and sale of oil and natural gas produced from the Beta, Diller and Marmalard projects. During 2016, the Fund entered into master agreements with Beta S&T and DH S&T pursuant to which Beta S&T and DH S&T are obligated to purchase from the Fund all of its interests in oil and natural gas produced from the Beta, Diller and Marmalard projects and sell such volumes to unrelated third party purchasers. Pursuant to the master agreements, Beta S&T and DH S&T are pass-through entities such that they receive no benefit or compensation for the services provided under the agreements or under any other agreements they enter into with regard to the oil and gas purchased from the Fund. The Fund and other funds managed by the Manager have agreed to indemnify, defend and hold harmless Beta S&T and DH S&T from and against all claims, liabilities, losses, causes of action, costs and expenses asserted against them as a result of or arising from any act or omission, breach and claims for losses or damages arising out of their dealing with third parties with respect to the transportation, processing or sale of oil and gas from the Beta, Diller and Marmalard projects. The revenues and expenses from the sale of oil and natural gas to third party purchasers are recorded as oil and gas revenue and operating expenses in the Fund's statements of operations. These revenues and operating expenses allocable to the Fund are based on the Fund's working interest ownership in the Beta, Diller and Marmalard projects.

At times, short-term payables and receivables, which do not bear interest, arise from transactions with affiliates in the ordinary course of business.

The Fund has working interest ownership in certain projects to acquire and develop oil and natural gas projects with other entities that are likewise managed by the Manager.

Profits and losses are allocated in accordance with the LLC Agreement. In general, profits and losses in any year are allocated 85% to shareholders and 15% to the Manager. The primary exception to this treatment is that all items of expense, loss, deduction and credit attributable to the expenditure of shareholders' capital contributions are allocated 99% to shareholders and 1% to the Manager.

**ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES**

The following table presents fees for services rendered by Deloitte & Touche LLP during the years ended December 31, 2016 and 2015.

| | Year ended December 31, 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Audit fees (1) | $ 88 | $ 88 |

(1) Fees for audit of annual financial statements, reviews of the related quarterly financial statements, and reviews of documents filed with the SEC.

**PART IV**

**ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES**

**(a)(1) Financial Statements**

See “Index to Financial Statements” set forth on page F-1.

**(a) (2) Financial Statement Schedules**

None.

**(a) (3)**

| EXHIBIT NUMBER | TITLE OF EXHIBIT | METHOD OF FILING |
|---|---|---|
| 3.1 | Certificate of Formation of Ridgewood Energy O Fund, LLC dated December 21, 2004 | Incorporated by reference to the Fund's Form 10 filed on April 21, 2006 |
| 3.2 | Limited Liability Company Agreement between Ridgewood Energy Corporation and Investors of Ridgewood Energy O Fund, LLC dated February 16, 2005 | Incorporated by reference to the Fund's Form 10 filed on April 21, 2006 |
| 10.1 | Credit Agreement dated as of November 27, 2012 by and among Ridgewood Energy O Fund, LLC, Ridgewood Energy Q Fund, LLC, Ridgewood Energy S Fund, LLC, Ridgewood Energy T Fund, LLC, Ridgewood Energy V Fund, LLC, Ridgewood Energy W Fund, LLC, Ridgewood Energy A-1 Fund, LLC, Ridgewood Energy B-1 Fund, LLC, Rahr Energy Investments LLC, as Administrative Agent, and certain Lenders party thereto | Incorporated by reference to the Fund's Form 8-K filed on December 3, 2012 |
| 10.2 | First Amendment to Credit Agreement dated September 30, 2016 by and among Ridgewood Energy O Fund, LLC, Ridgewood Energy Q Fund, LLC, Ridgewood Energy S Fund, LLC, Ridgewood Energy T Fund, LLC, Ridgewood Energy V Fund, LLC, Ridgewood Energy W Fund, LLC, Ridgewood Energy A-1 Fund, LLC, Ridgewood Energy B-1 Fund, LLC, Rahr Energy Investments LLC, as Administrative Agent, and certain Lenders party thereto | Filed herewith |
| 31.1 | Certification of Robert E. Swanson, Chief Executive Officer of the Fund, pursuant to Exchange Act Rule 13a-14(a) | Filed herewith |
| 31.2 | Certification of Kathleen P. McSherry, Executive Vice President and Chief Financial Officer of the Fund, pursuant to Exchange Act Rule 13a-14(a) | Filed herewith |
| 32 | Certifications pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, signed by Robert E. Swanson, Chief Executive Officer of the Fund and Kathleen P. McSherry, Executive Vice President and Chief Financial Officer of the Fund | Filed herewith |
| 99.1 | Report of Netherland, Sewell & Associates, Inc. | Filed herewith |
| 101.INS | XBRL Instance Document | Filed herewith |
| 101.SCH | XBRL Taxonomy Extension Schema | Filed herewith |

| | | |
|---|---|---|
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase | Filed herewith |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document | Filed herewith |
| 101.LAB | XBRL Taxonomy Extension Label Linkbase | Filed herewith |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase | Filed herewith |

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## SIGNATURES

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

**RIDGEWOOD ENERGY O FUND, LLC**

By: /s/ ROBERT E. SWANSON
Robert E. Swanson
Chief Executive Officer
(Principal Executive Officer)

Date: February 27, 2017

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

| Signature | Capacity | Date |
| --- | --- | --- |
| /s/ ROBERT E. SWANSON<br>Robert E. Swanson | Chief Executive Officer<br>(Principal Executive Officer) | February 27, 2017 |
| /s/ KATHLEEN P. MCSHERRY<br>Kathleen P. McSherry | Executive Vice President and Chief Financial Officer<br>(Principal Financial and Accounting Officer) | February 27, 2017 |
| **RIDGEWOOD ENERGY CORPORATION** | | |
| BY: /s/ ROBERT E. SWANSON<br>Robert E. Swanson | Chief Executive Officer of the Manager | February 27, 2017 |

| INDEX TO FINANCIAL STATEMENTS | PAGE |
|---|---|
| | |

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Manager of Ridgewood Energy O Fund, LLC:

We have audited the accompanying balance sheets of Ridgewood Energy O Fund, LLC (the "Fund") as of December 31, 2016 and 2015, and the related statements of operations, changes in members' capital, and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Fund is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Fund's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such financial statements present fairly, in all material respects, the financial position of Ridgewood Energy O Fund, LLC as of December 31, 2016 and 2015, and the results of its operations and its cash flows for the years then ended, in conformity with accounting principles generally accepted in the United States of America.

*/s/ Deloitte & Touche LLP*

Parsippany, New Jersey
February 27, 2017

**RIDGEWOOD ENERGY O FUND, LLC**
**BALANCE SHEETS**
**(in thousands, except share data)**

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 2,366 | $ 5,669 |
| Production receivable | 1,198 | 357 |
| Other current assets | 234 | - |
| Total current assets | 3,798 | 6,026 |
| Salvage fund | 2,405 | 2,009 |
| Investment in Delta House | 119 | 572 |
| Oil and gas properties: | | |
| Proved properties | 64,348 | 58,004 |
| Less: accumulated depletion and amortization | (22,242) | (18,310) |
| Total oil and gas properties, net | 42,106 | 39,694 |
| Total assets | $ 48,428 | $ 48,301 |
| **Liabilities and Members' Capital** | | |
| Current liabilities: | | |
| Due to operators | $ 1,650 | $ 821 |
| Accrued expenses | 2,985 | 1,233 |
| Current portion of long-term borrowings | 6,424 | - |
| Total current liabilities | 11,059 | 2,054 |
| Long-term borrowings | 17,349 | 22,085 |
| Asset retirement obligations | 2,821 | 3,420 |
| Other liabilities | 100 | 115 |
| Total liabilities | 31,329 | 27,674 |
| Commitments and contingencies (Note 4) | | |
| Members' capital: | | |
| Manager: | | |
| Distributions | (5,536) | (5,536) |
| Retained earnings | 4,116 | 3,884 |
| Manager's total | (1,420) | (1,652) |
| Shareholders: | | |
| Capital contributions (935 shares authorized; 870.6486 issued and outstanding) | 128,990 | 128,990 |
| Syndication costs | (14,742) | (14,742) |
| Distributions | (33,548) | (33,548) |
| Accumulated deficit | (62,181) | (58,421) |
| Shareholders' total | 18,519 | 22,279 |
| Total members' capital | 17,099 | 20,627 |
| Total liabilities and members' capital | $ 48,428 | $ 48,301 |

The accompanying notes are an integral part of these financial statements.

**RIDGEWOOD ENERGY O FUND, LLC**
**STATEMENTS OF OPERATIONS**
**(in thousands, except per share data)**

| | Year ended December 31, 2016 | 2015 |
|---|---|---|
| **Revenue** | | |
| Oil and gas revenue | $ 6,721 | $ 3,952 |
| **Expenses** | | |
| Depletion and amortization | 3,923 | 1,668 |
| Impairment of oil and gas properties | 13 | 266 |
| Management fees to affiliate (Note 2) | 1,282 | 1,399 |
| Operating expenses | 3,735 | 2,506 |
| General and administrative expenses | 186 | 160 |
| Total expenses | 9,139 | 5,999 |
| Loss from operations | (2,418) | (2,047) |
| **Other (loss) income** | | |
| Loss on investment in Delta House | (114) | - |
| Dividend income | 191 | 75 |
| Interest (expense) income, net | (1,187) | 7 |
| Total other (loss) income | (1,110) | 82 |
| Net loss | $ (3,528) | $ (1,965) |
| | | |
| ***Manager Interest*** | | |
| Net income (loss) | $ 232 | $ (9) |
| | | |
| ***Shareholder Interest*** | | |
| Net loss | $ (3,760) | $ (1,956) |
| Net loss per share | $ (4,318) | $ (2,246) |

The accompanying notes are an integral part of these financial statements.

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**RIDGEWOOD ENERGY O FUND, LLC**
**STATEMENTS OF CHANGES IN MEMBERS' CAPITAL**
**(in thousands, except share data)**

| | # of Shares | Manager | Shareholders | Total |
|---|---|---|---|---|
| **Balances, December 31, 2014** | 870.6486 | $ (1,616) | $ 24,385 | $ 22,769 |
| Distributions | - | (27) | (150) | (177) |
| Net loss | - | (9) | (1,956) | (1,965) |
| **Balances, December 31, 2015** | 870.6486 | (1,652) | 22,279 | 20,627 |
| Net income (loss) | - | 232 | (3,760) | (3,528) |
| **Balances, December 31, 2016** | 870.6486 | $ (1,420) | $ 18,519 | $ 17,099 |

The accompanying notes are an integral part of these financial statements.

**RIDGEWOOD ENERGY O FUND, LLC**
**STATEMENTS OF CASH FLOWS**
**(in thousands)**

| | Year ended December 31, 2016 | 2015 |
|---|---|---|
| **Cash flows from operating activities** | | |
| Net loss | $ (3,528) | $ (1,965) |
| Adjustments to reconcile net loss to net cash provided by operating activities: | | |
| Depletion and amortization | 3,923 | 1,668 |
| Impairment of oil and gas properties | 13 | 266 |
| Accretion expense | 154 | 94 |
| Loss on investment in Delta House | 114 | - |
| Amortization of debt discounts and deferred financing costs | 179 | - |
| Changes in assets and liabilities: | | |
| Increase in production receivable | (890) | (155) |
| (Increase) decrease in other current assets | (134) | 29 |
| Increase in due to operators | 58 | 193 |
| Increase in accrued expenses | 1,031 | 49 |
| Net cash provided by operating activities | 920 | 179 |
| **Cash flows from investing activities** | | |
| Capital expenditures for oil and gas properties and investment in Delta House | (5,496) | (13,987) |
| Proceeds from sale of investment in Delta House | 339 | - |
| Increase in salvage fund | (396) | (276) |
| Net cash used in investing activities | (5,553) | (14,263) |
| **Cash flows from financing activities** | | |
| Long-term borrowings | 1,330 | 16,200 |
| Distributions | - | (177) |
| Net cash provided by financing activities | 1,330 | 16,023 |
| Net (decrease) increase in cash and cash equivalents | (3,303) | 1,939 |
| Cash and cash equivalents, beginning of year | 5,669 | 3,730 |
| Cash and cash equivalents, end of year | $ 2,366 | $ 5,669 |
| **Supplemental disclosure of non-cash investing activities** | | |
| Advances used for capital expenditures in oil and gas properties reclassified to proved properties | $ - | $ 589 |

The accompanying notes are an integral part of these financial statements.

**RIDGEWOOD ENERGY O FUND, LLC**
**NOTES TO FINANCIAL STATEMENTS**

## 1. Organization and Summary of Significant Accounting Policies

***Organization***

The Ridgewood Energy O Fund, LLC (the "Fund"), a Delaware limited liability company, was formed on December 21, 2004 and operates pursuant to a limited liability company agreement (the "LLC Agreement") dated as of February 16, 2005 by and among Ridgewood Energy Corporation (the "Manager") and the shareholders of the Fund, which addresses matters such as the authority and voting rights of the Manager and shareholders, capitalization, transferability of membership interests, participation in costs and revenues, distribution of assets and dissolution and winding up. The Fund was organized to primarily acquire interests in oil and gas properties located in the United States offshore waters of Texas, Louisiana and Alabama in the Gulf of Mexico.

The Manager has direct and exclusive control over the management of the Fund's operations. With respect to project investments, the Manager locates potential projects, conducts due diligence, and negotiates and completes the transactions. The Manager performs, or arranges for the performance of, the management, advisory and administrative services required for Fund operations. Such services include, without limitation, the administration of shareholder accounts, shareholder relations and the preparation, review and dissemination of tax and other financial information and the management of the Fund's investments in projects. In addition, the Manager provides office space, equipment and facilities and other services necessary for Fund operations. The Manager also engages and manages contractual relations with unaffiliated custodians, depositories, accountants, attorneys, corporate fiduciaries, insurers, banks and others as required. See Notes 2, 3 and 4.

***Use of Estimates***

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenue and expense during the reporting period. On an ongoing basis, the Manager reviews its estimates, including those related to the fair value of financial instruments, depletion and amortization, determination of proved reserves, impairment of long-lived assets and asset retirement obligations. Actual results may differ from those estimates.

***Fair Value Measurements***

The fair value measurement guidance provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 inputs are unobservable inputs and include situations where there is little, if any, market activity for the instrument; hence, these inputs have the lowest priority.

***Cash and Cash Equivalents***

All highly liquid investments with maturities, when purchased, of three months or less, are considered cash equivalents. These balances, as well as cash on hand, are included in "Cash and cash equivalents" on the balance sheet. As of December 31, 2016, the Fund had no cash equivalents. At times, deposits may be in excess of federally insured limits, which are $250 thousand per insured financial institution. As of December 31, 2016, the Fund's bank balances were maintained in uninsured bank accounts at Wells Fargo Bank, N.A.

***Salvage Fund***

The Fund deposits in a separate interest-bearing account, or salvage fund, cash to provide for the dismantling and removal of production platforms and facilities and plugging and abandoning its wells at the end of their useful lives in accordance with applicable federal and state laws and regulations. Interest earned on the account will become part of the salvage fund. There are no restrictions on withdrawals from the salvage fund.

***Debt Discounts and Deferred Financing Costs***

Debt discounts and deferred financing costs include lender fees and other costs of acquiring debt (see Note 3. "Credit Agreement – Beta Project Financing") such as the conveyance of override royalty interests related to the Beta Project. These costs are deferred and amortized over the term of the debt period or until the redemption of the debt. Unamortized debt discounts and deferred financing costs are presented as a reduction of "Long-term borrowings" on the balance sheets (see Note 1. "Organization and Summary of Significant Accounting Policies - Recent Accounting Pronouncements").

During the period of asset construction, amortization expense, as a component of interest, is capitalized and included on the balance sheet within "Oil and gas properties" (see Note 3. "Credit Agreement – Beta Project Financing").

***Investment in Delta House***
The Fund has investments in Delta House Oil and Gas Lateral, LLC and Delta House FPS, LLC (collectively "Delta House"), legal entities that own interests in a deepwater floating production system operated by LLOG Exploration Company. The Fund accounts for its investment in Delta House using the cost method of accounting for investments as it does not have the ability to exercise significant influence over such investment. Under the cost method, the Fund recognizes an investment in the equity of an investee at cost. The Fund recognizes as income dividends received that are distributed from net accumulated earnings of the investee since the date of acquisition by the Fund. Dividends received in excess of earnings subsequent to the date of investment are considered a return of investment and are recorded as reductions of cost of the investment. The Fund reviews its cost method investment for impairment at each reporting period and when an event or change in circumstances has occurred that may have a significant adverse effect on the fair value of the investment. Losses on cost method investments including impairments that are deemed to be other than temporary are classified as non-operating losses in the Fund's statements of operations.

As of December 31, 2016, the Fund invested a total of $0.6 million in Delta House and has received cash from its investment totaling $0.6 million, of which $0.3 million relates to dividends received and $0.3 million relates to cash proceeds from the sale of approximately 74% of its investment, pursuant to a unit purchase agreement with D-Day Offshore Holdings, LLC dated October 31, 2016. Certain other funds managed by the Manager were also parties to this unit purchase agreement. The Fund adjusted the carrying value of its investment in Delta House in third quarter 2016 to fair value, which was determined based on the third party sale and recorded a loss on investment during the year ended December 31, 2016 of $0.1 million. The loss was included on the Fund's statement of operations within "Loss on investment in Delta House". Inputs used to estimate fair value of the investment in Delta House are categorized as Level 3 in the fair value hierarchy. As of December 31, 2016, the Fund's remaining carrying value for the investment in Delta House was $0.1 million.

***Oil and Gas Properties***
The Fund invests in oil and gas properties, which are operated by unaffiliated entities that are responsible for drilling, administering and producing activities pursuant to the terms of the applicable operating agreements with working interest owners. The Fund's portion of exploration, drilling, operating and capital equipment expenditures is billed by operators.

Acquisition, exploration and development costs are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and natural gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Costs of drilling and equipping productive wells and related production facilities are capitalized. The costs of exploratory wells are capitalized pending determination of whether proved reserves have been found. If proved commercial reserves are not found, exploratory well costs are expensed as dry-hole costs. At times, the Fund receives adjustments to certain wells from their respective operators upon review and audit of the wells' costs. Interest costs related to the Credit Agreement (see Note 3. "Credit Agreement – Beta Project Financing") are capitalized during the period of asset construction. Annual lease rentals and exploration expenses are expensed as incurred. All costs related to production activity, transportation expense and workover efforts are expensed as incurred.

Once a well has been determined to be fully depleted or upon the sale, retirement or abandonment of a property, the cost and related accumulated depletion and amortization, if any, is eliminated from the property accounts, and the resultant gain or loss is recognized.

As of December 31, 2016 and 2015, amounts recorded in due to operators totaling $1.2 million and $0.5 million, respectively, related to capital expenditures for oil and gas properties.

***Advances to Operators for Working Interests and Expenditures***
The Fund may be required to advance its share of the estimated succeeding month's expenditures to the operator for its oil and gas properties. As the costs are incurred, the advances are reclassified to proved properties.

***Asset Retirement Obligations***

For oil and gas properties, there are obligations to perform removal and remediation activities when the properties are retired. Upon the determination that a property is either proved or dry, a retirement obligation is incurred. The Fund recognizes the fair value of a liability for an asset retirement obligation in the period incurred. Plug and abandonment costs associated with unsuccessful projects are expensed as dry-hole costs. At least bi-annually, or more frequently if an event occurs that would dictate a change in assumptions or estimates underlying the obligations, the Fund reassesses all of its asset retirement obligations to determine whether any revisions to the obligations are necessary. The following table presents changes in asset retirement obligations during the years ended December 31, 2016 and 2015.

| | 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Balance, beginning of year | $ 3,420 | $ 1,730 |
| Liabilities incurred | 5 | 1,046 |
| Accretion expense | 154 | 94 |
| Revision of estimates | (758) | 550 |
| Balance, end of year | $ 2,821 | $ 3,420 |

As indicated above, the Fund maintains a salvage fund to provide for the funding of future asset retirement obligations.

***Syndication Costs***

Syndication costs are direct costs incurred by the Fund in connection with the offering of the Fund's shares, including professional fees, selling expenses and administrative costs payable to the Manager, an affiliate of the Manager and unaffiliated broker-dealers, which are reflected on the Fund's balance sheet as a reduction of shareholders' capital.

***Revenue Recognition and Imbalances***

Oil and gas revenues are recognized when oil and gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. The Fund uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Fund is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves net to the Fund will not be sufficient to enable the underproduced owner to recoup its entitled share through production. The Fund's recorded liability, if any, would be reflected in other liabilities. No receivables are recorded for those wells where the Fund has taken less than its share of production.

***Impairment of Long-Lived Assets***

The Fund reviews the carrying value of its oil and gas properties annually and when management determines that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments are determined by comparing estimated future net undiscounted cash flows to the carrying value at the time of the review. If the carrying value exceeds the estimated future net undiscounted cash flows, the carrying value of the asset is written down to fair value, which is determined using estimated future net discounted cash flows from the asset. The fair value determinations require considerable judgment and are sensitive to change. Different pricing assumptions, reserve estimates or discount rates could result in a different calculated impairment. Given the volatility of oil and natural gas prices, it is reasonably possible that the Fund's estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term.

Significant and consistent fluctuations in oil and natural gas prices since fourth quarter 2014 have impacted the fair value of the Fund's oil and gas properties. During the year ended December 31, 2016, the Fund recorded impairments of oil and gas properties of $13 thousand, which represented the carrying value of Eugene Island 346/347. The impairments were primarily attributable to declines in future oil and gas prices.

During the year ended December 31, 2015, the Fund recorded impairments of oil and gas properties of $0.3 million related to Eugene Island 346/347 and the Cobalt Project, which were attributable to both declines in future oil and gas prices and revisions to reserve estimates as provided by the Fund's independent petroleum engineers. The fair value of the impaired properties at the date of impairment was $0.1 million.

If oil and natural gas prices decline, even if only for a short period of time, it is possible that additional impairments of oil and gas properties will occur.

***Depletion and Amortization***
Depletion and amortization of the cost of proved oil and gas properties are calculated using the units-of-production method. Proved developed reserves are used as the base for depleting capitalized costs associated with successful exploratory well costs, development costs and related facilities, other than offshore platforms. The sum of proved developed and proved undeveloped reserves is used as the base for depleting or amortizing leasehold acquisition costs and costs to construct offshore platform and associated asset retirement costs. During the years ended December 31, 2016 and 2015, the Fund recorded $4 thousand and $0.2 million, respectively, of depletion expense related to adjustments to asset retirement obligations for fully depleted properties.

***Income Taxes***
No provision is made for income taxes in the financial statements. The Fund is a limited liability company, and as such, the Fund's income or loss is passed through and included in the tax returns of the Fund's shareholders. The Fund files U.S. Federal and State tax returns and the 2013 through 2015 tax returns remain open for examination by tax authorities.

***Income and Expense Allocation***
Profits and losses are allocated to shareholders and the Manager in accordance with the LLC Agreement.

***Distributions***
Distributions to shareholders are allocated in proportion to the number of shares held. The Manager determines whether available cash from operations, as defined in the LLC Agreement, will be distributed. Such distributions are allocated 85% to the shareholders and 15% to the Manager, as required by the LLC Agreement.

Available cash from dispositions, as defined in the LLC Agreement, will be paid 99% to shareholders and 1% to the Manager until the shareholders have received total distributions equal to their capital contributions. After shareholders have received distributions equal to their capital contributions, 85% of available cash from dispositions will be distributed to shareholders and 15% to the Manager.

***Recent Accounting Pronouncements***
In January 2016, the Financial Accounting Standards Board ("FASB") issued accounting guidance that requires, among other things, companies to measure investments in other entities, except those accounted for under the equity method, at fair value and recognize any changes in fair value in net income unless an election is made to record the investment at cost, less impairment and plus or minus subsequent adjustments for observable price changes with change in basis reported in current earnings. This pronouncement is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years, with early adoption not permitted. The Fund is currently evaluating the impact of this guidance on its financial statements.

In April 2015, the FASB issued accounting guidance related to the presentation of debt issuance costs on the balance sheet as a direct reduction from the carrying amount of the debt liability, consistent with debt discounts, rather than as an asset. Amortization of debt issuance costs will continue to be reported as interest expense. In August 2015, the FASB issued accounting guidance related to the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements which clarifies that companies may continue to present unamortized debt issuance costs associated with line of credit arrangements as an asset. These pronouncements became effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Fund adopted the accounting guidance in first quarter 2016, resulting in a one-time reclassification of $0.7 million of unamortized debt discounts and deferred financing costs from "Other assets" to "Long-term borrowings" on the balance sheet as of December 31, 2015. The adoption of these pronouncements did not impact the Fund's results of operations or cash flows.

In May 2014, the FASB issued accounting guidance on revenue recognition, which provides for a single five-step model to be applied to all revenue contracts with customers. In July 2015, the FASB issued a deferral of the effective date of the guidance to 2018, with early adoption permitted in 2017. In March 2016, the FASB issued accounting guidance, which clarifies the implementation guidance on principal versus agent considerations in the new revenue recognition standard. In April 2016, the FASB issued guidance on identifying performance obligations and licensing and in May 2016, the FASB issued final amendments which provided narrow scope improvements and practical expedients related to the implementation of the guidance. The accounting guidance may be applied either retrospectively or through the use of a modified-retrospective method. Based on the Fund's initial assessment of the accounting guidance, the Fund currently does not expect it will have a material impact on its results of operations or cash flows in the period after adoption. Under the accounting guidance, revenue is recognized as control transfers to the customer, as such the Fund expects the application of the accounting guidance to its existing contracts to be generally consistent with its current revenue recognition model. The Fund will continue the evaluation of the provisions of this accounting guidance, as well as new or emerging interpretations, as it relates to new contracts the Fund receives and in particular as it relates to disclosure requirements through the date of adoption, which is currently expected to be January 1, 2018.

## 2. Related Parties

Pursuant to the terms of the LLC Agreement, the Manager renders management, administrative and advisory services to the Fund. For such services, the Manager is entitled to an annual management fee, payable monthly, of 2.5% of total capital contributions, net of cumulative dry-hole and related well costs incurred by the Fund. In addition, pursuant to the terms of the LLC Agreement, the Manager is also permitted to waive the management fee at its own discretion. Such fee may be temporarily waived to accommodate the Fund's short-term capital commitments. Management fees during the years ended December 31, 2016 and 2015 were $1.3 million and $1.4 million, respectively.

The Manager is entitled to receive a 15% interest in cash distributions from operations made by the Fund. The Fund did not pay distributions during the year ended December 31, 2016. Distributions paid to the Manager during the year ended December 31, 2015 were $27 thousand.

None of the amounts paid to the Manager have been derived as a result of arm's length negotiations.

In May 2015, Beta Sales and Transport, LLC ("Beta S&T"), a wholly-owned subsidiary of the Manager, was formed to act as an aggregator to and as an accommodation for the Fund and other funds managed by the Manager (the "Ridgewood Beta Funds") to facilitate the transportation and sale of oil and gas produced from the Beta Project. On June 1, 2016, the Ridgewood Beta Funds entered into a master agreement with Beta S&T pursuant to which Beta S&T is obligated to purchase from Ridgewood Beta Funds all of their interests in oil and gas produced at the Beta Project and sell such volumes to unrelated third party purchasers.

In February 2015, DH Sales and Transport, LLC ("DH S&T"), a wholly-owned subsidiary of the Manager, was formed to act as an aggregator to and as an accommodation for the Fund and other funds managed by the Manager (the "Ridgewood Delta House Funds") to facilitate the transportation and sale of oil and gas produced from the Diller and Marmalard projects. On April 11, 2016, the Ridgewood Delta House Funds entered into a master agreement with DH S&T pursuant to which DH S&T is obligated to purchase from Ridgewood Delta House Funds all of their interests in oil and gas produced at the Diller and Marmalard projects and sell such volumes to unrelated third party purchasers.

Pursuant to the master agreements, Beta S&T and DH S&T are pass-through entities such that they receive no benefit or compensation for the services provided under the master agreements or under any other agreements they enter into with regard to the oil and gas purchased from the Ridgewood Beta Funds and Ridgewood Delta House Funds. Ridgewood Beta Funds and Ridgewood Delta House Funds have agreed to indemnify, defend and hold harmless Beta S&T and DH S&T from and against all claims, liabilities, losses, causes of action, costs and expenses asserted against them as a result of or arising from any act or omission, breach and claims for losses or damages arising out of their dealing with third parties with respect to the transportation, processing or sale of oil and gas from the Beta, Diller and Marmalard projects. The revenues and expenses from the sale of oil and natural gas to third party purchasers are recorded as oil and gas revenue and operating expenses in the Fund's statements of operations. These revenues and operating expenses allocable to the Fund are based on the Fund's working interest ownership in the Beta, Diller and Marmalard projects.

At times, short-term payables and receivables, which do not bear interest, arise from transactions with affiliates in the ordinary course of business.

The Fund has working interest ownership in certain projects to acquire and develop oil and natural gas projects with other entities that are likewise managed by the Manager.

## 3. Credit Agreement – Beta Project Financing

In November 2012, the Fund entered into a credit agreement (as amended on September 30, 2016, the "Credit Agreement") with Rahr Energy Investments LLC, as Administrative Agent and Lender (and any other banks or financial institutions that may in the future become a party thereto, collectively "Lenders") that provides for an aggregate loan commitment to the Fund of approximately $24.1 million ("Loan"), to provide capital toward the funding of the Fund's share of development costs on the Beta Project. Except in cases of fraud and breach of certain representations, the Loan is non-recourse to the Fund's other assets and secured solely by the Fund's interests in the Beta Project. Certain other funds managed by Ridgewood ("Ridgewood Funds", and when used with the Fund the "Ridgewood Participating Funds") have also executed the Credit Agreement. Pursuant to the Credit Agreement, each Ridgewood Participating Fund has a separate loan commitment from the Lenders and amounts borrowed are not joint and several obligations. Each of the Ridgewood Participating Funds' borrowings is secured solely by its separate interest in the Beta Project. Therefore, the Fund is liable for the repayment of its Loan and is not liable to the Lenders to repay any loan made to any other Ridgewood Funds. The Manager serves as the manager for each of the Ridgewood Participating Funds. As of December 31, 2016, in accordance with the terms of the Credit Agreement, there will be no additional borrowings available to the Ridgewood Participating Funds.

As of December 31, 2016 and 2015, the Fund had borrowings of $24.1 million and $22.8 million, respectively, under the Credit Agreement. The Loan bears interest at 8% compounded annually. Principal and interest are repaid at the lesser of (i) a monthly rate of 1.25% of the Fund's total principal outstanding as of July 31, 2016 for the first seven months beginning October 2016, and increases to a monthly rate of 4.5% thereafter until the Loan is repaid in full, and (ii) debt service amount as defined in the Credit Agreement, in no event later than December 31, 2020. The Loan may be prepaid by the Fund without premium or penalty.

The unamortized debt discounts and deferred financing costs of $0.4 million as of December 31, 2016 and $0.7 million as of December 31, 2015 are presented as a reduction of "Long-term borrowings" on the balance sheets (see Note 1. "Organization and Summary of Significant Accounting Policies - Recent Accounting Pronouncements"). Amortization expense of $0.2 million and $0.4 million during the years ended December 31, 2016 and 2015, respectively, were capitalized and included on the balance sheet within "Oil and gas properties". As a result of the Beta Project's commencement of production in third quarter 2016, amortization expense during the year ended December 31, 2016 of $0.2 million was expensed and is included on the statement of operations within "Interest (expense) income, net".

As of December 31, 2016 and 2015, interest costs of $2.2 million and $1.3 million, respectively, were capitalized and included on the balance sheet within "Oil and gas properties". Such amounts were accrued on the balance sheet within "Accrued expenses" as of December 31, 2016 and "Accrued expenses" and "Other liabilities" as of December 31, 2015. As a result of the Beta Project's commencement of production in third quarter 2016, interest costs during the year ended December 31, 2016 of $1.0 million were expensed and are included on the statement of operations within "Interest (expense) income, net". Such amounts are accrued on the balance sheet within "Accrued expenses". Interest payments on the Loan of $0.3 million as of December 31, 2016 related to capitalized interest costs. Such amounts are included within cash flows from investing activities on the statements of cash flows.

As additional consideration to the Lenders, the Fund has agreed to convey an overriding royalty interest ("ORRI") in its working interest in the Beta Project to the Lenders. The Fund's share of the Lender's aggregate ORRI is directly proportionate to its level of borrowing as a percentage of total borrowings of all Ridgewood Participating Funds. Such ORRI will not accrue or become payable to the Lenders until after the Loan is repaid in full. The Credit Agreement contains customary covenants, with which the Fund was in compliance as of December 31, 2016 and 2015.

## 4. Commitments and Contingencies

***Capital Commitments***

The Fund has entered into multiple agreements for the acquisition, drilling and development of its oil and gas properties. The estimated capital expenditures associated with these agreements vary depending on the stage of development on a property-by-property basis.

As of December 31, 2016, the Fund's estimated capital commitments related to its oil and gas properties were $15.7 million (which include asset retirement obligations for the Fund's projects of $5.9 million), of which $5.5 million is expected to be spent during the year ending December 31, 2017, which is primarily related to complete the final phase of the Beta Project. As a result of the continued development of the Beta Project, the Fund has experienced negative cash flows for year ended December 31, 2016. Additionally, current liabilities exceeded current assets as of December 31, 2016. Future results of operations and cash flows are dependent on the continued successful development and the related production of oil and gas revenues from the Beta Project. Based upon its current cash position and its current reserve estimates, the Fund expects cash flow from operations to be sufficient to cover its commitments, borrowing repayments, as well as ongoing operations. Reserve estimates are projections based on engineering data that cannot be measured with precision, require substantial judgment, and are subject to frequent revision. However, if cash flow from operations is not sufficient to meet the Fund's capital commitments, the Manager will temporarily waive all or a portion of the management fee as well as provide short-term financing to accommodate the Fund's short-term capital commitments if needed.

***Environmental Considerations***

The exploration for and development of oil and natural gas involves the extraction, production and transportation of materials which, under certain conditions, can be hazardous or cause environmental pollution problems. The Manager and operators of the Fund's properties are continually taking action they believe appropriate to satisfy applicable federal, state and local environmental regulations and do not currently anticipate that compliance with federal, state and local environmental regulations will have a material adverse effect upon capital expenditures, results of operations or the competitive position of the Fund in the oil and gas industry. However, due to the significant public and governmental interest in environmental matters related to those activities, the Manager cannot predict the effects of possible future legislation, rule changes, or governmental or private claims. As of December 31, 2016 and 2015, there were no known environmental contingencies that required adjustment to, or disclosure in, the Fund's financial statements.

During the past several years, the United States Congress, as well as certain regulatory agencies with jurisdiction over the Fund's business, have considered or proposed legislation or regulation relating to the upstream oil and gas industry both onshore and offshore. If any such proposals were to be enacted or adopted they could potentially materially impact the Fund's operations. It is not possible at this time to predict whether such legislation or regulation, if proposed, will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact the Fund's business. Any such future laws and regulations could result in increased compliance costs or additional operating restrictions, which could have a material adverse effect on the Fund's operating results and cash flows.

***BOEM Notice to Lessees on Supplemental Bonding***

On July 14, 2016, the Bureau of Ocean Energy Management ("BOEM") issued a Notice to Lessees ("NTL") that discontinued and materially replaced existing policies and procedures regarding financial security (i.e. supplemental bonding) for decommissioning obligations of lessees of federal oil and gas leases and owners of pipeline rights-of-way, rights-of use and easements on the Outer Continental Shelf ("Lessees"). Generally, the new NTL (i) ended the practice of excusing Lessees from providing such additional security where co-lessees had sufficient financial strength to meet such decommissioning obligations, (ii) established new criteria for determining financial strength and additional security requirements of such Lessees, (iii) provided acceptable forms of such additional security and (iv) replaced the waiver system with one of self-insurance. The new rule became effective as of September 12, 2016; however on January 6, 2017, the BOEM announced that it was suspending the implementation timeline for six months in certain circumstances. The Fund, as well as other industry participants, are working with the BOEM, its operators and working interest partners to determine and agree upon the correct level of decommissioning obligations to which they may be liable and the manner in which such obligations will be secured. The impact of the NTL, if enforced without change or amendment, may require the Fund to fully secure all of its potential abandonment liabilities to the BOEM satisfaction using one or more of the enumerated methods for doing so. Potentially this could increase costs to the Fund if the Fund is required to obtain additional supplemental bonding, fund escrow accounts or obtain letters of credit.

***Insurance Coverage***

The Fund is subject to all risks inherent in the exploration for and development of oil and natural gas. Insurance coverage as is customary for entities engaged in similar operations is maintained, but losses may occur from uninsurable risks or amounts in excess of existing insurance coverage. The occurrence of an event that is not insured or not fully insured could have a material adverse impact upon earnings and financial position. Moreover, insurance is obtained as a package covering all of the funds managed by the Manager. Depending on the extent, nature and payment of claims made by the Fund or other funds managed by the Manager, yearly insurance coverage may be exhausted and become insufficient to cover a claim by the Fund in a given year.

**Ridgewood Energy O Fund, LLC**
**Supplementary Financial Information**
**Information about Oil and Gas Producing Activities - Unaudited**

In accordance with the FASB guidance on disclosures of oil and gas producing activities, this section provides supplementary information on oil and gas exploration and producing activities of the Fund. The Fund is engaged solely in oil and gas activities, all of which are located in the United States offshore waters of Louisiana in the Gulf of Mexico.

**Table I - Capitalized Costs Relating to Oil and Gas Producing Activities**

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Proved properties | $ 64,348 | $ 58,004 |
| Total oil and gas properties | 64,348 | 58,004 |
| Accumulated depletion and amortization | (22,242) | (18,310) |
| Oil and gas properties, net | $ 42,106 | $ 39,694 |

**Table II - Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development**

| | Year ended December 31, 2016 | Year ended December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Exploration costs | $ 64 | $ 14 |
| Development costs | 6,163 | 14,719 |
| | $ 6,227 | $ 14,733 |

**Table III - Reserve Quantity Information**

Oil and gas reserves of the Fund have been estimated by independent petroleum engineers, Netherland, Sewell & Associates, Inc. at December 31, 2016 and 2015. These reserve disclosures have been prepared in compliance with the Securities and Exchange Commission rules. Due to inherent uncertainties and the limited nature of recovery data, estimates of reserve information are subject to change as additional information becomes available.

| | December 31, 2016 | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | United States | | | | | |
| | Oil (BBLS) | NGL (BBLS) | Gas (MCF) | Oil (BBLS) | NGL (BBLS) | Gas (MCF) |
| **Proved developed and undeveloped reserves:** | | | | | | |
| Beginning of year | 1,284,623 | 109,756 | 1,940,204 | 1,214,454 | 34,268 | 2,303,413 |
| Revisions of previous estimates (a) | (254,807) | 86,972 | 84,834 | 139,275 | 89,265 | (163,848) |
| Production | (142,016) | (13,898) | (279,288) | (69,106) | (13,777) | (199,361) |
| End of year | 887,800 | 182,830 | 1,745,750 | 1,284,623 | 109,756 | 1,940,204 |
| **Proved developed reserves:** | | | | | | |
| Beginning of year | 382,074 | 64,613 | 970,446 | 40,373 | 34,268 | 608,088 |
| End of year | 726,811 | 115,780 | 1,229,330 | 382,074 | 64,613 | 970,446 |
| **Proved undeveloped reserves:** | | | | | | |
| Beginning of year | 902,549 | 45,143 | 969,758 | 1,174,081 | - | 1,695,325 |
| End of year | 160,989 | 67,050 | 516,420 | 902,549 | 45,143 | 969,758 |

(a) Revisions of previous estimates were attributable to well performance.

**Table IV - Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

Summarized in the following table is information for the Fund with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows were determined based on average first-of-the-month pricing for the prior twelve month period. Future production and development costs are derived based on current costs assuming continuation of existing economic conditions.

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Future cash inflows | $ 38,457 | $ 66,145 |
| Future production costs | (13,555) | (16,390) |
| Future development costs | (9,218) | (20,044) |
| Future net cash flows | 15,684 | 29,711 |
| 10% annual discount for estimated timing of cash flows | (1,172) | (8,381) |
| Standardized measure of discounted future net cash flows | $ 14,512 | $ 21,330 |

**Table V - Changes in the Standardized Measure for Discounted Cash Flows**

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production volumes and costs.

| | Year ended December 31, 2016 | Year ended December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Net change in sales and transfer prices and in production costs related to future production | $ (13,465) | $ (37,873) |
| Sales and transfers of oil and gas produced during the period | (3,323) | (1,594) |
| Changes in estimated future development costs | 10,826 | 6,070 |
| Net change due to revisions in quantities estimates | (2,601) | 4,185 |
| Accretion of discount | 2,133 | 5,079 |
| Other | (388) | (5,322) |
| Aggregate change in the standardized measure of discounted future net cash flows for the year | $ (6,818) | $ (29,455) |

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves as the computations are based on a number of estimates. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates and governmental control. Actual future prices and costs are likely to be substantially different from the current price and cost estimates utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitation inherent therein.

**Exhibit 10.2**

# FIRST AMENDMENT
# TO
# CREDIT AGREEMENT

This **FIRST AMENDMENT TO CREDIT AGREEMENT** ("First Amendment") effective as of September 30, 2016, among Ridgewood Energy O Fund, LLC, a Delaware limited liability company, Ridgewood Energy Q Fund, LLC, a Delaware limited liability company, Ridgewood Energy S Fund, LLC, a Delaware limited liability company, Ridgewood Energy T Fund, LLC, a Delaware limited liability, Ridgewood Energy V Fund, LLC, a Delaware limited liability company, Ridgewood Energy W Fund, LLC, a Delaware limited liability company, Ridgewood Energy A-1 Fund, LLC, a Delaware limited liability company, and Ridgewood Energy B-1 Fund, LLC, a Delaware limited liability company (collectively the "Borrowers" and individually a "Borrower"); each of the Lenders from time to time party hereto; and Rahr Energy Investments LLC, a Delaware limited liability company, as administrative agent for the Lenders) in such capacity, together with its successors in such capacity, the "Administrative Agent"). The Borrowers, Lenders and the Administrative Agent shall be referred to herein collectively as the Parties and individually as a "Party".

## R E C I T A L S

A. Each Borrower, the Lenders and Administrative Agent have entered into a Credit Agreement, dated as of November 27, 2012 (as amended, restated, supplemented or otherwise modified from time to time in accordance with its provisions, the "Credit Agreement").

B. The Parties desire to amend the Credit Agreement on the terms and subject to the conditions set forth herein.

NOW THEREFORE, the Parties agree as follows:

1. **Definitions**. Capitalized terms used and not defined in this First Amendment shall have their respective meanings ascribed to them in the Credit Agreement.

2. **Amendments to the Credit Agreement.** The Credit Agreement is hereby amended as follows:

   (a) **Debt Service Cap.** The definition of "Debt Service Cap" shall be amended as follows:

   "Debt Service Cap" means, for any Borrower and any Monthly Payment Date, 70% of such Borrower's Net Revenues; *provided*, that if for any reason (other than Force Majeure) in any Measuring Interval beginning after the Dispensation End Date, such Borrower's Net Revenue Interest share of crude oil produced from the Project Properties is less than the minimum quantity set forth for such Borrower in the Minimum Targeted Production Schedule, then the Debt Service Cap for such Borrower shall be 100% until such Borrower is current in the payment of (1) its Monthly Payment Amounts and (2) all Prior Shortfall Amounts.

   For purposes of the definition of Debt Service Cap:

(A) "Dispensation End Date" shall mean the earlier to occur of (i) the date on which the third well on the Project Properties is placed into production and (ii) April 30, 2017.

(B) "Measuring Interval" shall mean, for any Monthly Payment Date, the three-calendar-month period beginning at the start of the fifth calendar month before the calendar month of the Monthly Payment Date, and ending at the end of the third calendar month before the calendar month of the Monthly Payment Date. For example, for the Monthly Payment Date of December 31, 2017, the Measuring Interval shall be August, September, and October of 2017.

(b) **Loans.** The definition of Loans shall be amended as follows:

**"**Loans**"** means the loans made by the Lenders to the Borrower pursuant to this Agreement; provided however, that as of January 1, 2017, Loans shall mean, at any point in time, the total outstanding balance of all loans made by the Lenders to the Borrower.

(c) **Monthly Fixed Amount.** The definition of Monthly Fixed Amount shall be amended as follows:

**"**Monthly Fixed Amount" for any Borrower means:

## Monthly Fixed Amount

| Borrower | 7/31/16 Principal | First 7 Payment Dates | Thereafter |
|---|---|---|---|
| O Fund | 22,800,000 | 285,000 | 1,026,000 |
| Q Fund | 3,000,000 | 37,500 | 135,000 |
| S Fund | 5,650,000 | 70,625 | 254,250 |
| T Fund | 2,900,000 | 36,250 | 130,500 |
| V Fund | 12,850,000 | 160,625 | 578,250 |
| W Fund | 5,650,000 | 70,625 | 254,250 |
| A-1 Fund | 2,900,000 | 36,250 | 130,500 |
| B-1 Fund | 12,350,000 | 154,375 | 555,750 |

(d) **Monthly Payment Amount**. The definition of "Monthly Payment Amount" shall be amended as follows:

"Monthly Payment Amount" means, for any Borrower and any Monthly Payment Date, an amount equal to such Borrower's Monthly Fixed Amount; provided that in no event shall the Monthly Payment Amount exceed the Debt Service Cap.

(e) **Monthly Payment Date**. The definition of "Monthly Payment Date" shall be amended as follows:

"Monthly Payment Date" means the last Business Day of each calendar month, the first being October 31, 2016.

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(f) **Net Revenues.** The definition of "Net Revenues" shall be amended as follows:

"Net Revenues" means, for any Borrower and any Monthly Payment Date, all proceeds payable to such Borrower arising from the sale of Hydrocarbons produced during the second calendar month preceding the calendar month in which such Monthly Payment Date occurs, less Borrower's share of (i) Existing Production Burdens payable with respect to such production, (ii) Operating Costs incurred by such Borrower with respect to such (and which have not been funded out of prior production proceeds from the Project Properties), and (iii) after the completion of the development contemplated by the APOD, Development Costs incurred during the second calendar month immediately preceding the calendar month in which such Monthly Payment Date occurs in accordance with the Walter APOD and not funded in whole or in part by loans made by Lender; provided that the aggregate expenses and costs of any Borrower subject to this clause (iii) shall not exceed such Borrower's Pro-Rata Share of $19.058 million.

(g) **Base Interest Rate.** Section 3.02 (a). The definition of "Base Interest Rate" shall be amended as follows:

Base Interest Rate. (i) Up to and including December 31, 2016, the outstanding unpaid balance of the Loans comprising each Borrowing shall bear interest at a rate per annum equal to eight (8%) percent compounded annually and (ii) on January 1, 2017, and annually on each January 1st thereafter, the total outstanding balance of all Loans made to each Borrower shall bear interest at a rate per annum equal to eight (8%) percent compounded.

(h) Section 8.01(o)(iv) shall be amended as follows:

(iv) calculations showing as to each Borrower the last occurrence, if any, of a Measuring Interval after the Dispensation End Date during which such Borrower's Net Revenue Interest share of crude oil produced from the Project Properties has been less than the minimum quantity set forth for such Borrower in the Minimum Targeted Production Schedule for any reason other than Force Majeure,

3. **Effect of First Amendment.** This First Amendment is a Loan Document. Except as expressly provided for herein, all of the terms and provisions of the Credit Agreement and other Loan Documents are and shall remain in full force and effect and are hereby ratified and confirmed by each Borrower, the Lenders and Administrative Agent. The amendments contained herein shall not be construed as a waiver or amendment of another provision of the Credit Agreement or the other Loan Documents or for any purpose except as expressly set forth herein or a consent to any further or future action on the part of any Party that would require and waiver or consent of the Administrative Agent.

4. **Conditions Precedent to the Effectiveness of the First Amendment.** This First Amendment shall not be effective until the Administrative Agent receives:
   (a) counterparts of this First Amendment signed by each Borrower, by each Lender and the Administrative Agent;
   (b) payment of all reasonable expenses, including reasonable legal fees and expenses of counsel to the Administrative Agent reasonably incurred by the Administrative Agent in connection with this First Amendment to the extent invoiced to the Borrowers prior to the date hereof; and
   (c) such other documents, agreements, instruments or items that the Administrative Agent may reasonably request.

5. **Representations and Warranties.** Each Borrower represents and warrants to each Lender and the Administrative Agent as follows:
   (a) The execution, delivery and performance by each Borrower of this First Amendment and the Credit Agreement, as hereby amended, have been duly authorized by all required corporate action.
   (b) All representations and warranties made or deemed made by each Borrower in the Loan Documents are true and correct as of the date hereof, except to the extent that such representations and warranties expressly relate solely to an earlier date (in which case such representations and warranties were true and accurate on and as of such earlier date) and except that for purposes of such representations and warranties, the representations and warranties contained in Section 7.04 of the Credit Agreement shall be deemed to refer to the most recent statements furnished pursuant to Section 8.01 of the Credit Agreement.
   (c) Since August 12, 2016, there has been no event or circumstance, either individually or in the aggregate that has or can be reasonably expected to have a Material Adverse Effect.
   (d) No Default or Event of Default has occurred and is continuing as of the date hereof.

6. **Successors and Assigns.** This First Amendment shall inure to the benefit of and be binding upon each Borrower, the Lenders, and the Administrative Agent and each of their respective successors and assigns.

7. **Governing Law.** This First Amendment shall be governed by and construed in accordance with the laws of the State of New York.

8. **Counterparts.** This First Amendment may be executed in any number of counterparts, all of which shall constitute one and the same agreement, and any Party hereto may execute this First Amendment by signing and delivering one or more counterparts.

9. **Expenses**. The Borrowers shall pay all reasonable fees and expenses paid or incurred by the Administrative Agent incident to this First Amendment, including, without limitation, the reasonable fees and expenses of the Administrative Agent's counsel in connection with the negotiation, preparation, delivery and execution of this First Amendment and any related documents.

10. **ENTIRETY. THIS FIRST AMENDMENT, THE CREDIT AGREEMENT, AND THE OTHER LOAN DOCUMENTS EMBODY THE ENTIRE AGREEMENT BETWEEN THE PARTIES AND SUPERSEDE ALL PRIOR AGREEMENTS AND UNDERSTANDINGS, IF ANY, RELATING TO THE SUBJECT MATTER HEREOF.**

IN WITNESS WHEREOF, the Parties have executed this First Amendment this 30th day of September, 2016.

BORROWER:

RIDGEWOOD ENERGY O FUND, LLC

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President- Legal

RIDGEWOOD ENERGY Q FUND, LLC

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

RIDGEWOOD ENERGY S FUND, LLC

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

RIDGEWOOD ENERGY T FUND, LLC.

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

RIDGEWOOD ENERGY V FUND, LLC

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

RIDGEWOOD ENERGY W FUND, LLC.

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

RIDGEWOOD ENERGY A-1 FUND, LLC.

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

RIDGEWOOD ENERGY B-1 FUND, LLC.

By: /s/ DANIEL V. GULINO
Name: Daniel V. Gulino
Title: Senior Vice President - Legal

ADMINISTRATIVE AGENT:

RAHR ENERGY INVESTMENTS LLC,
as Administrative Agent

By: /s/ LAWRENCE J. FOSSI
Name: Lawrence J. Fossi
Title: Manager

LENDER:

RAHR ENERGY INVESTMENTS LLC,
as a Lender

By: /s/ LAWRENCE J. FOSSI
Name: Lawrence J. Fossi
Title: Manager

**Exhibit 31.1**

**CERTIFICATION**

I, Robert E. Swanson, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ridgewood Energy O Fund, LLC;

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

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

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

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

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

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

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

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

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

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

| | |
|---|---|
| Dated: | February 27, 2017 |
| /s/ | ROBERT E. SWANSON |
| Name: | Robert E. Swanson |
| Title: | Chief Executive Officer<br>(Principal Executive Officer) |

**Exhibit 31.2**

**CERTIFICATION**

I, Kathleen P. McSherry, certify that:

1. I have reviewed this Annual Report on Form 10-K of Ridgewood Energy O Fund, LLC;

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

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

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

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

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

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

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

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

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

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

**Dated:** **February 27, 2017**

**/s/** **KATHLEEN P. MCSHERRY**

**Name:** **Kathleen P. McSherry**

**Title:** **Executive Vice President and Chief Financial Officer**
**(Principal Financial and Accounting Officer)**

**Exhibit 32**

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

In connection with this Annual Report on Form 10-K of the Ridgewood Energy O Fund, LLC (the "Fund") for the fiscal year ended December 31, 2016, as filed with the Securities and Exchange Commission on the date hereof, (the "Report"), each of the undersigned officers of the Fund hereby certifies, pursuant to 18 U.S.C. (section) 1350, as adopted pursuant to (section) 906 of the Sarbanes-Oxley Act of 2002, that to the best of their knowledge:

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

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Fund.

Dated: February 27, 2017

/s/ ROBERT E. SWANSON

Name: Robert E. Swanson
Title: Chief Executive Officer
(Principal Executive Officer)

Dated: February 27, 2017

/s/ KATHLEEN P. MCSHERRY

Name: Kathleen P. McSherry
Title: Executive Vice President and Chief Financial Officer
(Principal Financial and Accounting Officer)

A signed original of this written statement or other document authenticating, acknowledging, or otherwise adopting the signature that appears in typed form within the electronic version of this written statement has been provided to the Fund and will be retained by the Fund and furnished to the Securities and Exchange Commission or its staff upon request. The foregoing certification is being furnished solely pursuant to 18 U.S.C. Section 1350 and is not being filed as part of this report or as a separate disclosure document.

NETHERLAND, SEWELL & ASSOCIATES, INC.
WORLDWIDE PETROLEUM CONSULTANTS
ENGINEERING • GEOLOGY • GEOPHYSICS • PETROPHYSICS



February 3, 2017

Mr. W. Kent Webb
Ridgewood Energy Corporation
1254 Enclave Parkway, Suite 600
Houston, Texas 77077

Dear Mr. Webb:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2016, to the Ridgewood Energy O Fund, LLC (Ridgewood O Fund) interest in certain oil and gas properties located in federal waters in the Gulf of Mexico. We completed our evaluation on or about the date of this letter. It is our understanding that the proved reserves estimated in this report constitute all of the proved reserves owned by Ridgewood O Fund. The estimates in this report have been prepared in accordance with the definitions and regulations of the U.S. Securities and Exchange Commission (SEC) and, with the exception of the exclusion of future income taxes, conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas. Definitions are presented immediately following this letter. This report has been prepared for Ridgewood O Fund's use in filing with the SEC; in our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

We estimate the net reserves and future net revenue to the Ridgewood O Fund interest in these properties, as of December 31, 2016, to be:

| | Net Reserves | | | Future Net Revenue (M$) | |
|---|---|---|---|---|---|
| Category | Oil (MBBL) | NGL (MBBL) | Gas (MMCF) | Total | Present Worth at 10% |
| Proved Developed Producing | 552.6 | 53.0 | 630.5 | 10,883.1 | 11,013.3 |
| Proved Developed Non-Producing | 174.2 | 62.8 | 598.9 | 3,731.7 | 3,118.1 |
| Proved Undeveloped | 161.0 | 67.0 | 516.4 | 1,069.3 | 380.1 |
| Total Proved | 887.8 | 182.8 | 1,745.7 | 15,684.1 | 14,511.5 |

*Totals may not add because of rounding.*

The oil volumes shown include crude oil and condensate. Oil and natural gas liquids (NGL) volumes are expressed in thousands of barrels (MBBL); a barrel is equivalent to 42 United States gallons. Gas volumes are expressed in millions of cubic feet (MMCF) at standard temperature and pressure bases.

The estimates shown in this report are for proved reserves. As requested, probable and possible reserves that exist for these properties have not been included. This report does not include any value that could be attributed to interests in undeveloped acreage beyond those tracts for which undeveloped reserves have been estimated. Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. The estimates of reserves and future revenue included herein have not been adjusted for risk.

Gross revenue is Ridgewood O Fund's share of the gross (100 percent) revenue from the properties after deductions for the fixed portion of Delta House pipeline fees. Future net revenue is after deductions for Ridgewood O Fund's share of capital costs, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2016. For oil and NGL volumes, the average Light Louisiana Sweet spot price of $44.44 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.481 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $38.34 per barrel of oil, $9.97 per barrel of NGL, and $1.958 per MCF of gas.

Operating costs used in this report are based on operating expense records of Ridgewood Energy Corporation (Ridgewood) and our knowledge of similar offshore operations. These costs include the per-well overhead expenses allowed under joint operating agreements along with estimates of costs to be incurred at and below the district and field levels. Operating costs have been divided into field-level costs, per-well costs, and per-unit-of-production costs and include production handling agreement fees. Since all properties are nonoperated, headquarters general and administrative overhead expenses are not included. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by LLOG Bluewater, LLC (LLOG), the operator, for Marmalard Field and by Ridgewood for all other fields. These costs are based on authorizations for expenditure, internal planning budgets, and actual costs from recent activity. Capital costs are included as required for workovers, new development wells, and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report are Ridgewood's estimates of the costs to abandon the wells, platforms, and production facilities, net of any salvage value. Capital costs and abandonment costs are not escalated for inflation.

For the purposes of this report, we did not perform any field inspection of the properties, nor did we examine the mechanical operation or condition of the wells and facilities. We have not investigated possible environmental liability related to the properties; therefore, our estimates do not include any costs due to such possible liability.

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the Ridgewood O Fund interest. Therefore, our estimates of reserves and future revenue do not include adjustments for the settlement of any such imbalances; our projections are based on Ridgewood O Fund receiving its net revenue interest share of estimated future gross production. Additionally, we have been informed by Ridgewood that Ridgewood O Fund is not party to any firm transportation contracts for these properties.

The reserves shown in this report are estimates only and should not be construed as exact quantities. Proved reserves are those quantities of oil and gas which, by analysis of engineering and geoscience data, can be estimated with reasonable certainty to be economically producible; probable and possible reserves are those additional reserves which are sequentially less certain to be recovered than proved reserves. Estimates of reserves may increase or decrease as a result of market conditions, future operations, changes in regulations, or actual reservoir performance. In addition to the primary economic assumptions discussed herein, our estimates are based on certain assumptions including, but not limited to, that the properties will be developed consistent with current development plans as provided to us by Ridgewood and LLOG, that the properties will be operated in a prudent manner, that no governmental regulations or controls will be put in place that would impact the ability of the interest owner to recover the reserves, and that our projections of future production will prove consistent with actual performance. If the reserves are recovered, the revenues therefrom and the costs related thereto could be more or less than the estimated amounts. Because of governmental policies and uncertainties of supply and demand, the sales rates, prices received for the reserves, and costs incurred in recovering such reserves may vary from assumptions made while preparing this report.

For the purposes of this report, we used technical and economic data including, but not limited to, well logs, geologic maps, seismic data, well test data, production data, historical price and cost information, and property ownership interests. The reserves in this report have been estimated using deterministic methods; these estimates have been prepared in accordance with the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers (SPE Standards). We used standard engineering and geoscience methods, or a combination of methods, including performance analysis, volumetric analysis, analogy, and reservoir modeling, that we considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for behind-pipe zones, non-producing zones, undeveloped locations, and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based; such reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, our conclusions necessarily represent only informed professional judgment.

The data used in our estimates were obtained from Ridgewood, LLOG, other interest owners, public data sources, and the nonconfidential files of Netherland, Sewell & Associates, Inc. (NSAI) and were accepted as accurate. Supporting work data are on file in our office. We have not examined the titles to the properties or independently confirmed the actual degree or type of interest owned. The technical persons primarily responsible for preparing the estimates presented herein meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the SPE Standards. John R. Cliver, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2009 and has over 5 years of prior industry experience. Shane M. Howell, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2005 and has over 7 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

**NETHERLAND, SEWELL & ASSOCIATES, INC.**
Texas Registered Engineering Firm F-2699

By: /s/ C.H. (Scott) Rees III
C.H. (Scott) Rees III, P.E.
Chairman and Chief Executive Officer

By: /s/ John R. Cliver
John R. Cliver, P.E. 107216
Vice President

By: /s/ Shane M. Howell
Shane M. Howell, P.G. 11276
Vice President

Date Signed: February 3, 2017

Date Signed: February 3, 2017

JRC:JLM

NETHERLAND, SEWELL & ASSOCIATES, INC.

# DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

The following definitions are set forth in U.S. Securities and Exchange Commission (SEC) Regulation S-X Section 210.4-10(a). Also included is supplemental information from (1) the 2007 Petroleum Resources Management System approved by the Society of Petroleum Engineers, (2) the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, and (3) the SEC's Compliance and Disclosure Interpretations.

(1) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(2) *Analogous reservoir*. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest);
(ii) Same environment of deposition;
(iii) Similar geological structure; and
(iv) Same drive mechanism.

*Instruction to paragraph (a)(2)*: Reservoir properties must, in the aggregate, be no more favorable in the analog than in the reservoir of interest.

(3) *Bitumen*. Bitumen, sometimes referred to as natural bitumen, is petroleum in a solid or semi-solid state in natural deposits with a viscosity greater than 10,000 centipoise measured at original temperature in the deposit and atmospheric pressure, on a gas free basis. In its natural state it usually contains sulfur, metals, and other non-hydrocarbons.

(4) *Condensate*. Condensate is a mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

(5) *Deterministic estimate*. The method of estimating reserves or resources is called deterministic when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

(6) *Developed oil and gas reserves*. Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and
(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

*Supplemental definitions from the 2007 Petroleum Resources Management System:*

*Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.*

*Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.*

(7) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
(iv) Provide improved recovery systems.

(8) *Development project*. A development project is the means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field, or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

(9) *Development well*. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(10) *Economically producible*. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue shall be determined at the terminal point of oil and gas producing activities as defined in paragraph (a)(16) of this section.

(11) *Estimated ultimate recovery (EUR)*. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

(12) *Exploration costs*. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.
(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
(iii) Dry hole contributions and bottom hole contributions.
(iv) Costs of drilling and equipping exploratory wells.
(v) Costs of drilling exploratory-type stratigraphic test wells.

(13) *Exploratory well*. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir. Generally, an exploratory well is any well that is not a development well, an extension well, a service well, or a stratigraphic test well as those items are defined in this section.

(14) *Extension well*. An extension well is a well drilled to extend the limits of a known reservoir.

(15) *Field*. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(16) *Oil and gas producing activities.*

(i) Oil and gas producing activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations;

(B) The acquisition of property rights or properties for the purpose of further exploration or for the purpose of removing the oil or gas from such properties;

(C) The construction, drilling, and production activities necessary to retrieve oil and gas from their natural reservoirs, including the acquisition, construction, installation, and maintenance of field gathering and storage systems, such as:

*(1)* Lifting the oil and gas to the surface; and

*(2)* Gathering, treating, and field processing (as in the case of processing gas to extract liquid hydrocarbons); and

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(D) Extraction of saleable hydrocarbons, in the solid, liquid, or gaseous state, from oil sands, shale, coalbeds, or other nonrenewable natural resources which are intended to be upgraded into synthetic oil or gas, and activities undertaken with a view to such extraction.

*Instruction 1 to paragraph (a)(16)(i)*: The oil and gas production function shall be regarded as ending at a "terminal point", which is the outlet valve on the lease or field storage tank. If unusual physical or operational circumstances exist, it may be appropriate to regard the terminal point for the production function as:

a. The first point at which oil, gas, or gas liquids, natural or synthetic, are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal; and

b. In the case of natural resources that are intended to be upgraded into synthetic oil or gas, if those natural resources are delivered to a purchaser prior to upgrading, the first point at which the natural resources are delivered to a main pipeline, a common carrier, a refinery, a marine terminal, or a facility which upgrades such natural resources into synthetic oil or gas.

*Instruction 2 to paragraph (a)(16)(i):* For purposes of this paragraph (a)(16), the term *saleable hydrocarbons* means hydrocarbons that are saleable in the state in which the hydrocarbons are delivered.

(ii) Oil and gas producing activities do not include:

(A) Transporting, refining, or marketing oil and gas;

(B) Processing of produced oil, gas, or natural resources that can be upgraded into synthetic oil or gas by a registrant that does not have the legal right to produce or a revenue interest in such production;

(C) Activities relating to the production of natural resources other than oil, gas, or natural resources from which synthetic oil and gas can be extracted; or

(D) Production of geothermal steam.

(17) *Possible reserves.* Possible reserves are those additional reserves that are less certain to be recovered than probable reserves.

(i) When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

(ii) Possible reserves may be assigned to areas of a reservoir adjacent to probable reserves where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir by a defined project.

(iii) Possible reserves also include incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

(iv) The proved plus probable and proved plus probable plus possible reserves estimates must be based on reasonable alternative technical and commercial interpretations within the reservoir or subject project that are clearly documented, including comparisons to results in successful similar projects.

(v) Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

(vi) Pursuant to paragraph (a)(22)(iii) of this section, where direct observation has defined a highest known oil (HKO) elevation and the potential exists for an associated gas cap, proved oil reserves should be assigned in the structurally higher portions of the reservoir above the HKO only if the higher contact can be established with reasonable certainty through reliable technology. Portions of the reservoir that do not meet this reasonable certainty criterion may be assigned as probable and possible oil or gas based on reservoir fluid properties and pressure gradient interpretations.

(18) *Probable reserves.* Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered.

(i) When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(ii) Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir.

(iii) Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

(iv) See also guidelines in paragraphs (a)(17)(iv) and (a)(17)(vi) of this section.

(19) *Probabilistic estimate.* The method of estimation of reserves or resources is called probabilistic when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

(20) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

(21) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(22) *Proved oil and gas reserves.* Proved oil and gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. 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.

(i) The area of the reservoir considered as proved includes:

(A) The area identified by drilling and limited by fluid contacts, if any, and
(B) 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 gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons (LKH) as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated 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.

(iv) 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:

(A) 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

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

(B) The project has been approved for development by all necessary parties and entities, including governmental entities.

(v) 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.

(23) *Proved properties.* Properties with proved reserves.

(24) *Reasonable certainty.* If deterministic methods are used, reasonable certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

(25) *Reliable technology.* Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

(26) *Reserves.* Reserves are estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substances to market, and all permits and financing required to implement the project.

*Note to paragraph (a)(26)*: Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

*Excerpted from the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas:*

*932-235-50-30 A standardized measure of discounted future net cash flows relating to an entity's interests in both of the following shall be disclosed as of the end of the year:*

a. *Proved oil and gas reserves (see paragraphs 932-235-50-3 through 50-11B)*
b. *Oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the entity participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (see paragraph 932-235-50-7).*

*The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes.*

*932-235-50-31 All of the following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraphs 932-235-50-3 through 50-11B:*

a. *Future cash inflows. These shall be computed by applying prices used in estimating the entity's proved oil and gas reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.*

| | |
|---|---|
| *b.* | *Future development and production costs. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.* |
| *c.* | *Future income tax expenses. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the entity's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to tax deductions and tax credits and allowances relating to the entity's proved oil and gas reserves.* |
| *d.* | *Future net cash flows. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.* |

## DEFINITIONS OF OIL AND GAS RESERVES

Adapted from U.S. Securities and Exchange Commission Regulation S-X Section 210.4-10(a)

> e. *Discount. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.*
> f. *Standardized measure of discounted future net cash flows. This amount is the future net cash flows less the computed discount.*

(27) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(28) *Resources.* Resources are quantities of oil and gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

(29) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(30) *Stratigraphic test well.* A stratigraphic test well is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

(31) *Undeveloped oil and gas reserves.* Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

> *From the SEC's Compliance and Disclosure Interpretations (October 26, 2009):*
>
> *Although several types of projects — such as constructing offshore platforms and development in urban areas, remote locations or environmentally sensitive locations — by their nature customarily take a longer time to develop and therefore often do justify longer time periods, this determination must always take into consideration all of the facts and circumstances. No particular type of project per se justifies a longer time period, and any extension beyond five years should be the exception, and not the rule.*
>
> *Factors that a company should consider in determining whether or not circumstances justify recognizing reserves even though development may extend past five years include, but are not limited to, the following:*
>
> - *The company's level of ongoing significant development activities in the area to be developed (for example, drilling only the minimum number of wells necessary to maintain the lease generally would not constitute significant development activities);*
> - *The company's historical record at completing development of comparable long-term projects;*
> - *The amount of time in which the company has maintained the leases, or booked the reserves, without significant development activities;*
> - *The extent to which the company has followed a previously adopted development plan (for example, if a company has changed its development plan several times without taking significant steps to implement any of those plans, recognizing proved undeveloped reserves typically would not be appropriate); and*

- *The extent to which delays in development are caused by external factors related to the physical operating environment (for example, restrictions on development on Federal lands, but not obtaining government permits), rather than by internal factors (for example, shifting resources to develop properties with higher priority).*

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, as defined in paragraph (a)(2) of this section, or by other evidence using reliable technology establishing reasonable certainty.

(32) *Unproved properties.* Properties with no proved reserves.

| Document and Entity Information - USD ($) $ in Thousands | 12 Months Ended Dec. 31, 2016 | Feb. 27, 2017 |
|---|---|---|
| **Document And Entity Information [Abstract]** | | |
| Document Type | 10-K | |
| Amendment Flag | false | |
| Document Period End Date | Dec. 31, 2016 | |
| Entity Registrant Name | Ridgewood Energy O Fund LLC | |
| Entity Central Index Key | 0001315061 | |
| Current Fiscal Year End Date | --12-31 | |
| Document Fiscal Period Focus | FY | |
| Document Fiscal Year Focus | 2016 | |
| Entity Filer Category | Smaller Reporting Company | |
| Entity Units Outstanding | | 870.6486 |
| Entity Current Reporting Status | Yes | |
| Entity Well-known Seasoned Issuer | No | |
| Entity Voluntary Filers | No | |
| Entity Public Float | $ 0 | |

| BALANCE SHEETS - USD ($) $ in Thousands | Dec. 31, 2016 | Dec. 31, 2015 |
|---|---|---|
| **Current assets:** | | |
| Cash and cash equivalents | $ 2,366 | $ 5,669 |
| Production receivable | 1,198 | 357 |
| Other current assets | 234 | |
| Total current assets | 3,798 | 6,026 |
| Salvage fund | 2,405 | 2,009 |
| Investment in Delta House | 119 | 572 |
| **Oil and gas properties:** | | |
| Proved properties | 64,348 | 58,004 |
| Less: accumulated depletion and amortization | (22,242) | (18,310) |
| Total oil and gas properties, net | 42,106 | 39,694 |
| Total assets | 48,428 | 48,301 |
| **Current liabilities:** | | |
| Due to operators | 1,650 | 821 |
| Accrued expenses | 2,985 | 1,233 |
| Current portion of long-term borrowings | 6,424 | |
| Total current liabilities | 11,059 | 2,054 |
| Long-term borrowings | 17,349 | 22,085 |
| Asset retirement obligations | 2,821 | 3,420 |
| Other liabilities | 100 | 115 |
| Total liabilities | 31,329 | 27,674 |
| Commitments and contingencies (Note 4) | | |
| **Members' capital:** | | |
| Distributions | (5,536) | (5,536) |
| Retained earnings | 4,116 | 3,884 |
| Manager's total | (1,420) | (1,652) |
| Capital contributions (935 shares authorized; 870.6486 issued and outstanding) | 128,990 | 128,990 |
| Syndication costs | (14,742) | (14,742) |
| Distributions | (33,548) | (33,548) |
| Accumulated deficit | (62,181) | (58,421) |
| Shareholders' total | 18,519 | 22,279 |
| Total members' capital | 17,099 | 20,627 |
| Total liabilities and members' capital | $ 48,428 | $ 48,301 |

| BALANCE SHEETS (Parenthetical) - shares | Dec. 31, 2016 | Dec. 31, 2015 |
|---|---|---|
| **Statement of Financial Position [Abstract]** | | |
| Shares authorized | 935 | 935 |
| Shares issued | 870.6486 | 870.6486 |
| Shares outstanding | 870.6486 | 870.6486 |

| STATEMENTS OF OPERATIONS - USD ($) $ in Thousands | 12 Months Ended | |
|---|---|---|
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Revenue** | | |
| Oil and gas revenue | $ 6,721 | $ 3,952 |
| **Expenses** | | |
| Depletion and amortization | 3,923 | 1,668 |
| Impairment of oil and gas properties | 13 | 266 |
| Management fees to affiliate (Note 2) | 1,282 | 1,399 |
| Operating expenses | 3,735 | 2,506 |
| General and administrative expenses | 186 | 160 |
| Total expenses | 9,139 | 5,999 |
| Loss from operations | (2,418) | (2,047) |
| **Other (loss) income** | | |
| Loss on investment in Delta House | (114) | |
| Dividend income | 191 | 75 |
| Interest (expense) income, net | (1,187) | 7 |
| Total other (loss) income | (1,110) | 82 |
| Net loss | (3,528) | (1,965) |
| **Manager Interest** | | |
| Net income (loss) | 232 | (9) |
| **Shareholder Interest** | | |
| Net loss | $ (3,760) | $ (1,956) |
| Net loss per share | $ (4,318) | $ (2,246) |

| STATEMENTS OF CHANGES IN PARTNERS CAPITAL - USD ($) $ in Thousands | # of Shares [Member] | Manager [Member] | Shareholders [Member] | Total |
|---|---|---|---|---|
| Balances at Dec. 31, 2014 | | $ (1,616) | $ 24,385 | $ 22,769 |
| Balances, shares at Dec. 31, 2014 | 870.6486 | | | |
| Distributions | | (27) | (150) | (177) |
| Net income (loss) | | (9) | (1,956) | (1,965) |
| Balances at Dec. 31, 2015 | | (1,652) | 22,279 | $ 20,627 |
| Balances, shares at Dec. 31, 2015 | 870.6486 | | | 870.6486 |
| Net income (loss) | | 232 | (3,760) | $ (3,528) |
| Balances at Dec. 31, 2016 | | $ (1,420) | $ 18,519 | $ 17,099 |
| Balances, shares at Dec. 31, 2016 | 870.6486 | | | 870.6486 |

| STATEMENTS OF CASH FLOWS - USD ($) $ in Thousands | 12 Months Ended | |
| --- | --- | --- |
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Cash flows from operating activities** | | |
| Net loss | $ (3,528) | $ (1,965) |
| **Adjustments to reconcile net loss to net cash provided by operating activities:** | | |
| Depletion and amortization | 3,923 | 1,668 |
| Impairment of oil and gas properties | 13 | 266 |
| Accretion expense | 154 | 94 |
| Loss on investment in Delta House | 114 | |
| Amortization of debt discounts and deferred financing costs | 179 | |
| **Changes in assets and liabilities:** | | |
| Increase in production receivable | (890) | (155) |
| (Increase) decrease in other current assets | (134) | 29 |
| Increase in due to operators | 58 | 193 |
| Increase in accrued expenses | 1,031 | 49 |
| Net cash provided by operating activities | 920 | 179 |
| **Cash flows from investing activities** | | |
| Capital expenditures for oil and gas properties and investment in Delta House | (5,496) | (13,987) |
| Proceeds from sale of investment in Delta House | 339 | |
| Increase in salvage fund | (396) | (276) |
| Net cash used in investing activities | (5,553) | (14,263) |
| **Cash flows from financing activities** | | |
| Long-term borrowings | 1,330 | 16,200 |
| Distributions | | (177) |
| Net cash provided by financing activities | 1,330 | 16,023 |
| Net (decrease) increase in cash and cash equivalents | (3,303) | 1,939 |
| Cash and cash equivalents, beginning of year | 5,669 | 3,730 |
| Cash and cash equivalents, end of year | 2,366 | 5,669 |
| **Supplemental disclosure of non-cash investing activities** | | |
| Advances used for capital expenditures in oil and gas properties reclassified to proved properties | | $ 589 |

| Organization and Summary of Significant Accounting Policies | 12 Months Ended Dec. 31, 2016 |
|---|---|
| **Organization, Consolidation and Presentation of Financial Statements [Abstract]** | |
| Organization and Summary of Significant Accounting Policies | **1. Organization and Summary of Significant Accounting Policies** |

***Organization***

The Ridgewood Energy O Fund, LLC (the "Fund"), a Delaware limited liability company, was formed on December 21, 2004 and operates pursuant to a limited liability company agreement (the "LLC Agreement") dated as of February 16, 2005 by and among Ridgewood Energy Corporation (the "Manager") and the shareholders of the Fund, which addresses matters such as the authority and voting rights of the Manager and shareholders, capitalization, transferability of membership interests, participation in costs and revenues, distribution of assets and dissolution and winding up. The Fund was organized to primarily acquire interests in oil and gas properties located in the United States offshore waters of Texas, Louisiana and Alabama in the Gulf of Mexico.

The Manager has direct and exclusive control over the management of the Fund's operations. With respect to project investments, the Manager locates potential projects, conducts due diligence, and negotiates and completes the transactions. The Manager performs, or arranges for the performance of, the management, advisory and administrative services required for Fund operations. Such services include, without limitation, the administration of shareholder accounts, shareholder relations and the preparation, review and dissemination of tax and other financial information and the management of the Fund's investments in projects. In addition, the Manager provides office space, equipment and facilities and other services necessary for Fund operations. The Manager also engages and manages contractual relations with unaffiliated custodians, depositories, accountants, attorneys, corporate fiduciaries, insurers, banks and others as required. See Notes 2, 3 and 4.

***Use of Estimates***

The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenue and expense during the reporting period. On an ongoing basis, the Manager reviews its estimates, including those related to the fair value of financial instruments, depletion and amortization, determination of proved reserves, impairment of long-lived assets and asset retirement obligations. Actual results may differ from those estimates.

***Fair Value Measurements***

The fair value measurement guidance provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 inputs are unobservable inputs and include situations where there is little, if any, market activity for the instrument; hence, these inputs have the lowest priority.

***Cash and Cash Equivalents***

All highly liquid investments with maturities, when purchased, of three months or less, are considered cash equivalents. These balances, as well as cash on hand, are included in "Cash and cash equivalents" on the balance sheet. As of December 31, 2016, the Fund had no cash equivalents. At times, deposits may be in excess of federally insured limits, which are $250 thousand per insured financial institution. As of December 31, 2016, the Fund's bank balances were maintained in uninsured bank accounts at Wells Fargo Bank, N.A.

***Salvage Fund***
The Fund deposits in a separate interest-bearing account, or salvage fund, cash to provide for the dismantling and removal of production platforms and facilities and plugging and abandoning its wells at the end of their useful lives in accordance with applicable federal and state laws and regulations. Interest earned on the account will become part of the salvage fund. There are no restrictions on withdrawals from the salvage fund.

***Debt Discounts and Deferred Financing Costs***
Debt discounts and deferred financing costs include lender fees and other costs of acquiring debt (see Note 3. "Credit Agreement – Beta Project Financing") such as the conveyance of override royalty interests related to the Beta Project. These costs are deferred and amortized over the term of the debt period or until the redemption of the debt. Unamortized debt discounts and deferred financing costs are presented as a reduction of "Long-term borrowings" on the balance sheets (see Note 1. "Organization and Summary of Significant Accounting Policies - Recent Accounting Pronouncements").

During the period of asset construction, amortization expense, as a component of interest, is capitalized and included on the balance sheet within "Oil and gas properties" (see Note 3. "Credit Agreement – Beta Project Financing").

***Investment in Delta House***
The Fund has investments in Delta House Oil and Gas Lateral, LLC and Delta House FPS, LLC (collectively "Delta House"), legal entities that own interests in a deepwater floating production system operated by LLOG Exploration Company. The Fund accounts for its investment in Delta House using the cost method of accounting for investments as it does not have the ability to exercise significant influence over such investment. Under the cost method, the Fund recognizes an investment in the equity of an investee at cost. The Fund recognizes as income dividends received that are distributed from net accumulated earnings of the investee since the date of acquisition by the Fund. Dividends received in excess of earnings subsequent to the date of investment are considered a return of investment and are recorded as reductions of cost of the investment. The Fund reviews its cost method investment for impairment at each reporting period and when an event or change in circumstances has occurred that may have a significant adverse effect on the fair value of the investment. Losses on cost method investments including impairments that are deemed to be other than temporary are classified as non-operating losses in the Fund's statements of operations.

As of December 31, 2016, the Fund invested a total of $0.6 million in Delta House and has received cash from its investment totaling $0.6 million, of which $0.3 million relates to dividends received and $0.3 million relates to cash proceeds from the sale of approximately 74% of its investment, pursuant to a unit purchase agreement with D-Day Offshore Holdings, LLC dated October 31, 2016. Certain other funds managed by the Manager were also parties to this unit purchase agreement. The Fund adjusted the carrying value of its investment in Delta House in third quarter 2016 to fair value, which was determined based on the third party sale and recorded a loss on investment during the year ended December 31, 2016 of $0.1 million. The loss was included on the Fund's statement of operations within "Loss on investment in Delta House". Inputs used to estimate fair value of the investment in Delta House are categorized as Level 3 in the fair value hierarchy. As of December 31, 2016, the Fund's remaining carrying value for the investment in Delta House was $0.1 million.

***Oil and Gas Properties***
The Fund invests in oil and gas properties, which are operated by unaffiliated entities that are responsible for drilling, administering and producing activities pursuant to the terms of the applicable operating agreements with working interest owners. The Fund's portion of exploration, drilling, operating and capital equipment expenditures is billed by operators.

Acquisition, exploration and development costs are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and natural gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Costs of drilling and equipping productive wells and related production facilities are capitalized. The costs of exploratory wells are capitalized pending determination of whether proved reserves have been found. If proved commercial reserves are not found, exploratory well costs are expensed as dry-hole costs. At times, the Fund receives adjustments to certain wells from their respective operators upon review and audit of the wells' costs. Interest costs related to the Credit Agreement (see Note 3. "Credit Agreement – Beta Project Financing") are capitalized during the period of asset construction. Annual lease rentals and exploration expenses are expensed as incurred. All costs related to production activity, transportation expense and workover efforts are expensed as incurred.

Once a well has been determined to be fully depleted or upon the sale, retirement or abandonment of a property, the cost and related accumulated depletion and amortization, if any, is eliminated from the property accounts, and the resultant gain or loss is recognized.

As of December 31, 2016 and 2015, amounts recorded in due to operators totaling $1.2 million and $0.5 million, respectively, related to capital expenditures for oil and gas properties.

***Advances to Operators for Working Interests and Expenditures***
The Fund may be required to advance its share of the estimated succeeding month's expenditures to the operator for its oil and gas properties. As the costs are incurred, the advances are reclassified to proved properties.

***Asset Retirement Obligations***
For oil and gas properties, there are obligations to perform removal and remediation activities when the properties are retired. Upon the determination that a property is either proved or dry, a retirement obligation is incurred. The Fund recognizes the fair value of a liability for an asset retirement obligation in the period incurred. Plug and abandonment costs associated with unsuccessful projects are expensed as dry-hole costs. At least bi-annually, or more frequently if an event occurs that would dictate a change in assumptions or estimates underlying the obligations, the Fund reassesses all of its asset retirement obligations to determine whether any revisions to the obligations are necessary. The following table presents changes in asset retirement obligations during the years ended December 31, 2016 and 2015.

| | **2016** | **2015** |
|---|---|---|
| | **(in thousands)** | |
| Balance, beginning of year | $ 3,420 | $ 1,730 |
| Liabilities incurred | 5 | 1,046 |
| Accretion expense | 154 | 94 |
| Revision of estimates | (758) | 550 |
| Balance, end of year | $ 2,821 | $ 3,420 |

As indicated above, the Fund maintains a salvage fund to provide for the funding of future asset retirement obligations.

***Syndication Costs***
Syndication costs are direct costs incurred by the Fund in connection with the offering of the Fund's shares, including professional fees, selling expenses and administrative costs payable to the Manager, an affiliate of the Manager and unaffiliated broker-dealers, which are reflected on the Fund's balance sheet as a reduction of shareholders' capital.

***Revenue Recognition and Imbalances***
Oil and gas revenues are recognized when oil and gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue

is reasonably assured. The Fund uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Fund is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves net to the Fund will not be sufficient to enable the underproduced owner to recoup its entitled share through production. The Fund's recorded liability, if any, would be reflected in other liabilities. No receivables are recorded for those wells where the Fund has taken less than its share of production.

***Impairment of Long-Lived Assets***
The Fund reviews the carrying value of its oil and gas properties annually and when management determines that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments are determined by comparing estimated future net undiscounted cash flows to the carrying value at the time of the review. If the carrying value exceeds the estimated future net undiscounted cash flows, the carrying value of the asset is written down to fair value, which is determined using estimated future net discounted cash flows from the asset. The fair value determinations require considerable judgment and are sensitive to change. Different pricing assumptions, reserve estimates or discount rates could result in a different calculated impairment. Given the volatility of oil and natural gas prices, it is reasonably possible that the Fund's estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term.

Significant and consistent fluctuations in oil and natural gas prices since fourth quarter 2014 have impacted the fair value of the Fund's oil and gas properties. During the year ended December 31, 2016, the Fund recorded impairments of oil and gas properties of $13 thousand, which represented the carrying value of Eugene Island 346/347. The impairments were primarily attributable to declines in future oil and gas prices.

During the year ended December 31, 2015, the Fund recorded impairments of oil and gas properties of $0.3 million related to Eugene Island 346/347 and the Cobalt Project, which were attributable to both declines in future oil and gas prices and revisions to reserve estimates as provided by the Fund's independent petroleum engineers. The fair value of the impaired properties at the date of impairment was $0.1 million.

If oil and natural gas prices decline, even if only for a short period of time, it is possible that additional impairments of oil and gas properties will occur.

***Depletion and Amortization***
Depletion and amortization of the cost of proved oil and gas properties are calculated using the units-of-production method. Proved developed reserves are used as the base for depleting capitalized costs associated with successful exploratory well costs, development costs and related facilities, other than offshore platforms. The sum of proved developed and proved undeveloped reserves is used as the base for depleting or amortizing leasehold acquisition costs and costs to construct offshore platform and associated asset retirement costs. During the years ended December 31, 2016 and 2015, the Fund recorded $4 thousand and $0.2 million, respectively, of depletion expense related to adjustments to asset retirement obligations for fully depleted properties.

***Income Taxes***
No provision is made for income taxes in the financial statements. The Fund is a limited liability company, and as such, the Fund's income or loss is passed through and included in the tax returns of the Fund's shareholders. The Fund files U.S. Federal and State tax returns and the 2013 through 2015 tax returns remain open for examination by tax authorities.

***Income and Expense Allocation***
Profits and losses are allocated to shareholders and the Manager in accordance with the LLC Agreement.

***Distributions***
Distributions to shareholders are allocated in proportion to the number of shares held. The Manager determines whether available cash from operations, as defined in the LLC Agreement, will be distributed. Such distributions are allocated 85% to the shareholders and 15% to the Manager, as required by the LLC Agreement.

Available cash from dispositions, as defined in the LLC Agreement, will be paid 99% to shareholders and 1% to the Manager until the shareholders have received total distributions equal to their capital contributions. After shareholders have received distributions equal to their capital contributions, 85% of available cash from dispositions will be distributed to shareholders and 15% to the Manager.

***Recent Accounting Pronouncements***
In January 2016, the Financial Accounting Standards Board ("FASB") issued accounting guidance that requires, among other things, companies to measure investments in other entities, except those accounted for under the equity method, at fair value and recognize any changes in fair value in net income unless an election is made to record the investment at cost, less impairment and plus or minus subsequent adjustments for observable price changes with change in basis reported in current earnings. This pronouncement is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years, with early adoption not permitted. The Fund is currently evaluating the impact of this guidance on its financial statements.

In April 2015, the FASB issued accounting guidance related to the presentation of debt issuance costs on the balance sheet as a direct reduction from the carrying amount of the debt liability, consistent with debt discounts, rather than as an asset. Amortization of debt issuance costs will continue to be reported as interest expense. In August 2015, the FASB issued accounting guidance related to the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements which clarifies that companies may continue to present unamortized debt issuance costs associated with line of credit arrangements as an asset. These pronouncements became effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Fund adopted the accounting guidance in first quarter 2016, resulting in a one-time reclassification of $0.7 million of unamortized debt discounts and deferred financing costs from "Other assets" to "Long-term borrowings" on the balance sheet as of December 31, 2015. The adoption of these pronouncements did not impact the Fund's results of operations or cash flows.

In May 2014, the FASB issued accounting guidance on revenue recognition, which provides for a single five-step model to be applied to all revenue contracts with customers. In July 2015, the FASB issued a deferral of the effective date of the guidance to 2018, with early adoption permitted in 2017. In March 2016, the FASB issued accounting guidance, which clarifies the implementation guidance on principal versus agent considerations in the new revenue recognition standard. In April 2016, the FASB issued guidance on identifying performance obligations and licensing and in May 2016, the FASB issued final amendments which provided narrow scope improvements and practical expedients related to the implementation of the guidance. The accounting guidance may be applied either retrospectively or through the use of a modified-retrospective method. Based on the Fund's initial assessment of the accounting guidance, the Fund currently does not expect it will have a material impact on its results of operations or cash flows in the period after adoption. Under the accounting guidance, revenue is recognized as control transfers to the customer, as such the Fund expects the application of the accounting guidance to its existing contracts to be generally consistent with its current revenue recognition model. The Fund will continue the evaluation of the provisions of this accounting guidance, as well as new or emerging interpretations, as it relates to new contracts the Fund receives and in particular as it relates to disclosure requirements through the date of adoption, which is currently expected to be January 1, 2018.

| Related Parties | 12 Months Ended Dec. 31, 2016 |
| --- | --- |

**Related Party Transactions [Abstract]**

Related Parties

**2. Related Parties**

Pursuant to the terms of the LLC Agreement, the Manager renders management, administrative and advisory services to the Fund. For such services, the Manager is entitled to an annual management fee, payable monthly, of 2.5% of total capital contributions, net of cumulative dry-hole and related well costs incurred by the Fund. In addition, pursuant to the terms of the LLC Agreement, the Manager is also permitted to waive the management fee at its own discretion. Such fee may be temporarily waived to accommodate the Fund's short-term capital commitments. Management fees during the years ended December 31, 2016 and 2015 were $1.3 million and $1.4 million, respectively.

The Manager is entitled to receive a 15% interest in cash distributions from operations made by the Fund. The Fund did not pay distributions during the year ended December 31, 2016. Distributions paid to the Manager during the year ended December 31, 2015 were $27 thousand.

None of the amounts paid to the Manager have been derived as a result of arm's length negotiations.

In May 2015, Beta Sales and Transport, LLC ("Beta S&T"), a wholly-owned subsidiary of the Manager, was formed to act as an aggregator to and as an accommodation for the Fund and other funds managed by the Manager (the "Ridgewood Beta Funds") to facilitate the transportation and sale of oil and gas produced from the Beta Project. On June 1, 2016, the Ridgewood Beta Funds entered into a master agreement with Beta S&T pursuant to which Beta S&T is obligated to purchase from Ridgewood Beta Funds all of their interests in oil and gas produced at the Beta Project and sell such volumes to unrelated third party purchasers.

In February 2015, DH Sales and Transport, LLC ("DH S&T"), a wholly-owned subsidiary of the Manager, was formed to act as an aggregator to and as an accommodation for the Fund and other funds managed by the Manager (the "Ridgewood Delta House Funds") to facilitate the transportation and sale of oil and gas produced from the Diller and Marmalard projects. On April 11, 2016, the Ridgewood Delta House Funds entered into a master agreement with DH S&T pursuant to which DH S&T is obligated to purchase from Ridgewood Delta House Funds all of their interests in oil and gas produced at the Diller and Marmalard projects and sell such volumes to unrelated third party purchasers.

Pursuant to the master agreements, Beta S&T and DH S&T are pass-through entities such that they receive no benefit or compensation for the services provided under the master agreements or under any other agreements they enter into with regard to the oil and gas purchased from the Ridgewood Beta Funds and Ridgewood Delta House Funds. Ridgewood Beta Funds and Ridgewood Delta House Funds have agreed to indemnify, defend and hold harmless Beta S&T and DH S&T from and against all claims, liabilities, losses, causes of action, costs and expenses asserted against them as a result of or arising from any act or omission, breach and claims for losses or damages arising out of their dealing with third parties with respect to the transportation, processing or sale of oil and gas from the Beta, Diller and Marmalard projects. The revenues and expenses from the sale of oil and natural gas to third party purchasers are recorded as oil and gas revenue and operating expenses in the Fund's statements of operations. These revenues and operating expenses allocable to the Fund are based on the Fund's working interest ownership in the Beta, Diller and Marmalard projects.

At times, short-term payables and receivables, which do not bear interest, arise from transactions with affiliates in the ordinary course of business.

The Fund has working interest ownership in certain projects to acquire and develop oil and natural gas projects with other entities that are likewise managed by the Manager.

| Credit Agreement - Beta Project Financing | 12 Months Ended Dec. 31, 2016 |
|---|---|
| **Debt Disclosure [Abstract]** | |
| Credit Agreement - Beta Project Financing | **3. Credit Agreement – Beta Project Financing**<br><br>In November 2012, the Fund entered into a credit agreement (as amended on September 30, 2016, the "Credit Agreement") with Rahr Energy Investments LLC, as Administrative Agent and Lender (and any other banks or financial institutions that may in the future become a party thereto, collectively "Lenders") that provides for an aggregate loan commitment to the Fund of approximately $24.1 million ("Loan"), to provide capital toward the funding of the Fund's share of development costs on the Beta Project. Except in cases of fraud and breach of certain representations, the Loan is non-recourse to the Fund's other assets and secured solely by the Fund's interests in the Beta Project. Certain other funds managed by Ridgewood ("Ridgewood Funds", and when used with the Fund the "Ridgewood Participating Funds") have also executed the Credit Agreement. Pursuant to the Credit Agreement, each Ridgewood Participating Fund has a separate loan commitment from the Lenders and amounts borrowed are not joint and several obligations. Each of the Ridgewood Participating Funds' borrowings is secured solely by its separate interest in the Beta Project. Therefore, the Fund is liable for the repayment of its Loan and is not liable to the Lenders to repay any loan made to any other Ridgewood Funds. The Manager serves as the manager for each of the Ridgewood Participating Funds. As of December 31, 2016, in accordance with the terms of the Credit Agreement, there will be no additional borrowings available to the Ridgewood Participating Funds.<br><br>As of December 31, 2016 and 2015, the Fund had borrowings of $24.1 million and $22.8 million, respectively, under the Credit Agreement. The Loan bears interest at 8% compounded annually. Principal and interest are repaid at the lesser of (i) a monthly rate of 1.25% of the Fund's total principal outstanding as of July 31, 2016 for the first seven months beginning October 2016, and increases to a monthly rate of 4.5% thereafter until the Loan is repaid in full, and (ii) debt service amount as defined in the Credit Agreement, in no event later than December 31, 2020. The Loan may be prepaid by the Fund without premium or penalty.<br><br>The unamortized debt discounts and deferred financing costs of $0.4 million as of December 31, 2016 and $0.7 million as of December 31, 2015 are presented as a reduction of "Long-term borrowings" on the balance sheets (see Note 1. "Organization and Summary of Significant Accounting Policies - Recent Accounting Pronouncements"). Amortization expense of $0.2 million and $0.4 million during the years ended December 31, 2016 and 2015, respectively, were capitalized and included on the balance sheet within "Oil and gas properties". As a result of the Beta Project's commencement of production in third quarter 2016, amortization expense during the year ended December 31, 2016 of $0.2 million was expensed and is included on the statement of operations within "Interest (expense) income, net".<br><br>As of December 31, 2016 and 2015, interest costs of $2.2 million and $1.3 million, respectively, were capitalized and included on the balance sheet within "Oil and gas properties". Such amounts were accrued on the balance sheet within "Accrued expenses" as of December 31, 2016 and "Accrued expenses" and "Other liabilities" as of December 31, 2015. As a result of the Beta Project's commencement of production in third quarter 2016, interest costs during the year ended December 31, 2016 of $1.0 million were expensed and are included on the statement of operations within "Interest (expense) income, net". Such amounts are accrued on the balance sheet within "Accrued expenses". Interest payments on the Loan of $0.3 million as of December 31, 2016 related to capitalized interest costs. Such amounts are included within cash flows from investing activities on the statements of cash flows.<br><br>As additional consideration to the Lenders, the Fund has agreed to convey an overriding royalty interest ("ORRI") in its working interest in the Beta Project to the Lenders. The Fund's share of the Lender's aggregate ORRI is directly proportionate to its level of borrowing as a percentage of total borrowings of all Ridgewood Participating Funds. Such ORRI will not accrue or become |

payable to the Lenders until after the Loan is repaid in full. The Credit Agreement contains customary covenants, with which the Fund was in compliance as of December 31, 2016 and 2015.

| Commitments and Contingencies | 12 Months Ended Dec. 31, 2016 |
|---|---|
| **Commitments and Contingencies Disclosure [Abstract]** | |
| Commitments and Contingencies | **4. Commitments and Contingencies**<br><br>***Capital Commitments***<br>The Fund has entered into multiple agreements for the acquisition, drilling and development of its oil and gas properties. The estimated capital expenditures associated with these agreements vary depending on the stage of development on a property-by-property basis.<br><br>As of December 31, 2016, the Fund's estimated capital commitments related to its oil and gas properties were $15.7 million (which include asset retirement obligations for the Fund's projects of $5.9 million), of which $5.5 million is expected to be spent during the year ending December 31, 2017, which is primarily related to complete the final phase of the Beta Project. As a result of the continued development of the Beta Project, the Fund has experienced negative cash flows for year ended December 31, 2016. Additionally, current liabilities exceeded current assets as of December 31, 2016. Future results of operations and cash flows are dependent on the continued successful development and the related production of oil and gas revenues from the Beta Project. Based upon its current cash position and its current reserve estimates, the Fund expects cash flow from operations to be sufficient to cover its commitments, borrowing repayments, as well as ongoing operations. Reserve estimates are projections based on engineering data that cannot be measured with precision, require substantial judgment, and are subject to frequent revision. However, if cash flow from operations is not sufficient to meet the Fund's capital commitments, the Manager will temporarily waive all or a portion of the management fee as well as provide short-term financing to accommodate the Fund's short-term capital commitments if needed.<br><br>***Environmental Considerations***<br>The exploration for and development of oil and natural gas involves the extraction, production and transportation of materials which, under certain conditions, can be hazardous or cause environmental pollution problems. The Manager and operators of the Fund's properties are continually taking action they believe appropriate to satisfy applicable federal, state and local environmental regulations and do not currently anticipate that compliance with federal, state and local environmental regulations will have a material adverse effect upon capital expenditures, results of operations or the competitive position of the Fund in the oil and gas industry. However, due to the significant public and governmental interest in environmental matters related to those activities, the Manager cannot predict the effects of possible future legislation, rule changes, or governmental or private claims. As of December 31, 2016 and 2015, there were no known environmental contingencies that required adjustment to, or disclosure in, the Fund's financial statements.<br><br>During the past several years, the United States Congress, as well as certain regulatory agencies with jurisdiction over the Fund's business, have considered or proposed legislation or regulation relating to the upstream oil and gas industry both onshore and offshore. If any such proposals were to be enacted or adopted they could potentially materially impact the Fund's operations. It is not possible at this time to predict whether such legislation or regulation, if proposed, will be adopted as initially written, if at all, or how legislation or new regulation that may be adopted would impact the Fund's business. Any such future laws and regulations could result in increased compliance costs or additional operating restrictions, which could have a material adverse effect on the Fund's operating results and cash flows.<br><br>***BOEM Notice to Lessees on Supplemental Bonding***<br>On July 14, 2016, the Bureau of Ocean Energy Management ("BOEM") issued a Notice to Lessees ("NTL") that discontinued and materially replaced existing policies and procedures regarding |

financial security (i.e. supplemental bonding) for decommissioning obligations of lessees of federal oil and gas leases and owners of pipeline rights-of-way, rights-of use and easements on the Outer Continental Shelf ("Lessees"). Generally, the new NTL (i) ended the practice of excusing Lessees from providing such additional security where co-lessees had sufficient financial strength to meet such decommissioning obligations, (ii) established new criteria for determining financial strength and additional security requirements of such Lessees, (iii) provided acceptable forms of such additional security and (iv) replaced the waiver system with one of self-insurance. The new rule became effective as of September 12, 2016; however on January 6, 2017, the BOEM announced that it was suspending the implementation timeline for six months in certain circumstances. The Fund, as well as other industry participants, are working with the BOEM, its operators and working interest partners to determine and agree upon the correct level of decommissioning obligations to which they may be liable and the manner in which such obligations will be secured. The impact of the NTL, if enforced without change or amendment, may require the Fund to fully secure all of its potential abandonment liabilities to the BOEM satisfaction using one or more of the enumerated methods for doing so. Potentially this could increase costs to the Fund if the Fund is required to obtain additional supplemental bonding, fund escrow accounts or obtain letters of credit.

***Insurance Coverage***

The Fund is subject to all risks inherent in the exploration for and development of oil and natural gas. Insurance coverage as is customary for entities engaged in similar operations is maintained, but losses may occur from uninsurable risks or amounts in excess of existing insurance coverage. The occurrence of an event that is not insured or not fully insured could have a material adverse impact upon earnings and financial position. Moreover, insurance is obtained as a package covering all of the funds managed by the Manager. Depending on the extent, nature and payment of claims made by the Fund or other funds managed by the Manager, yearly insurance coverage may be exhausted and become insufficient to cover a claim by the Fund in a given year.

| Information about Oil and Gas Producing Activities | 12 Months Ended Dec. 31, 2016 |
|---|---|
| **Information About Oil And Gas Producing Activities [Abstract]** | |
| Information about Oil and Gas Producing Activities | |

**Ridgewood Energy O Fund, LLC**
**Supplementary Financial Information**
**Information about Oil and Gas Producing Activities - Unaudited**

In accordance with the FASB guidance on disclosures of oil and gas producing activities, this section provides supplementary information on oil and gas exploration and producing activities of the Fund. The Fund is engaged solely in oil and gas activities, all of which are located in the United States offshore waters of Louisiana in the Gulf of Mexico.

**Table I - Capitalized Costs Relating to Oil and Gas Producing Activities**

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Proved properties | $ 64,348 | $ 58,004 |
| Total oil and gas properties | 64,348 | 58,004 |
| Accumulated depletion and amortization | (22,242) | (18,310) |
| Oil and gas properties, net | $ 42,106 | $ 39,694 |

**Table II - Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development**

| | Year ended December 31, 2016 | Year ended December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Exploration costs | $ 64 | $ 14 |
| Development costs | 6,163 | 14,719 |
| | $ 6,227 | $ 14,733 |

**Table III - Reserve Quantity Information**

Oil and gas reserves of the Fund have been estimated by independent petroleum engineers, Netherland, Sewell & Associates, Inc. at December 31, 2016 and 2015. These reserve disclosures have been prepared in compliance with the Securities and Exchange Commission rules. Due to inherent uncertainties and the limited nature of recovery data, estimates of reserve information are subject to change as additional information becomes available.

| | December 31, 2016 | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | United States | | | | | |
| | Oil (BBLS) | NGL (BBLS) | Gas (MCF) | Oil (BBLS) | NGL (BBLS) | Gas (MCF) |
| **Proved developed and undeveloped reserves:** | | | | | | |
| Beginning of year | 1,284,623 | 109,756 | 1,940,204 | 1,214,454 | 34,268 | 2,303,413 |
| Revisions of previous estimates (a) | (254,807) | 86,972 | 84,834 | 139,275 | 89,265 | (163,848) |
| Production | (142,016) | (13,898) | (279,288) | (69,106) | (13,777) | (199,361) |
| End of year | 887,800 | 182,830 | 1,745,750 | 1,284,623 | 109,756 | 1,940,204 |
| **Proved developed reserves:** | | | | | | |
| Beginning of year | 382,074 | 64,613 | 970,446 | 40,373 | 34,268 | 608,088 |
| End of year | 726,811 | 115,780 | 1,229,330 | 382,074 | 64,613 | 970,446 |
| **Proved undeveloped reserves:** | | | | | | |
| Beginning of year | 902,549 | 45,143 | 969,758 | 1,174,081 | - | 1,695,325 |
| End of year | 160,989 | 67,050 | 516,420 | 902,549 | 45,143 | 969,758 |

(a) Revisions of previous estimates were attributable to well performance.

**Table IV - Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

Summarized in the following table is information for the Fund with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows were determined based on average first-of-the-month pricing for the prior twelve month period. Future production and development costs are derived based on current costs assuming continuation of existing economic conditions.

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Future cash inflows | $ 38,457 | $ 66,145 |
| Future production costs | (13,555) | (16,390) |
| Future development costs | (9,218) | (20,044) |
| Future net cash flows | 15,684 | 29,711 |
| 10% annual discount for estimated timing of cash flows | (1,172) | (8,381) |
| Standardized measure of discounted future net cash flows | $ 14,512 | $ 21,330 |

**Table V - Changes in the Standardized Measure for Discounted Cash Flows**

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production volumes and costs.

| | Year ended December 31, 2016 | Year ended December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Net change in sales and transfer prices and in production costs related to future production | $ (13,465) | $ (37,873) |
| Sales and transfers of oil and gas produced during the period | (3,323) | (1,594) |
| Changes in estimated future development costs | 10,826 | 6,070 |
| Net change due to revisions in quantities estimates | (2,601) | 4,185 |
| Accretion of discount | 2,133 | 5,079 |
| Other | (388) | (5,322) |
| Aggregate change in the standardized measure of discounted future net cash flows for the year | $ (6,818) | $ (29,455) |

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from or current value of, existing proved reserves as the computations are based on a number of estimates. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates and governmental control. Actual future prices and costs are likely to be substantially different from the current price and cost estimates utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitation inherent therein.

| Organization and Summary of Significant Accounting Policies (Policy) | 12 Months Ended Dec. 31, 2016 |
|---|---|
| Organization, Consolidation and Presentation of Financial Statements [Abstract] | |
| Use of Estimates | ***Use of Estimates***<br>The preparation of financial statements in accordance with accounting principles generally accepted in the United States of America ("GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenue and expense during the reporting period. On an ongoing basis, the Manager reviews its estimates, including those related to the fair value of financial instruments, depletion and amortization, determination of proved reserves, impairment of long-lived assets and asset retirement obligations. Actual results may differ from those estimates. |
| Fair Value Measurements | ***Fair Value Measurements***<br>The fair value measurement guidance provides a hierarchy that prioritizes and defines the types of inputs used to measure fair value. The fair value hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 inputs are unobservable inputs and include situations where there is little, if any, market activity for the instrument; hence, these inputs have the lowest priority. |
| Cash and Cash Equivalents | ***Cash and Cash Equivalents***<br>All highly liquid investments with maturities, when purchased, of three months or less, are considered cash equivalents. These balances, as well as cash on hand, are included in "Cash and cash equivalents" on the balance sheet. As of December 31, 2016, the Fund had no cash equivalents. At times, deposits may be in excess of federally insured limits, which are $250 thousand per insured financial institution. As of December 31, 2016, the Fund's bank balances were maintained in uninsured bank accounts at Wells Fargo Bank, N.A. |
| Salvage Fund | ***Salvage Fund***<br>The Fund deposits in a separate interest-bearing account, or salvage fund, cash to provide for the dismantling and removal of production platforms and facilities and plugging and abandoning its wells at the end of their useful lives in accordance with applicable federal and state laws and regulations. Interest earned on the account will become part of the salvage fund. There are no restrictions on withdrawals from the salvage fund. |
| Debt Discounts and Deferred Financing Costs | ***Debt Discounts and Deferred Financing Costs***<br>Debt discounts and deferred financing costs include lender fees and other costs of acquiring debt (see Note 3. "Credit Agreement – Beta Project Financing") such as the conveyance of override royalty interests related to the Beta Project. These costs are deferred and amortized over the term of the debt period or until the redemption of the debt. Unamortized debt discounts and deferred financing costs are presented as a reduction of "Long-term borrowings" on the balance sheets (see Note 1. "Organization and Summary of Significant Accounting Policies - Recent Accounting Pronouncements").<br><br>During the period of asset construction, amortization expense, as a component of interest, is capitalized and included on the balance sheet within "Oil and gas properties" (see Note 3. "Credit Agreement – Beta Project Financing"). |
| Investment in Delta House | ***Investment in Delta House***<br>The Fund has investments in Delta House Oil and Gas Lateral, LLC and Delta House FPS, LLC (collectively "Delta House"), legal entities that own interests in a deepwater floating production system operated by LLOG Exploration Company. The Fund accounts for its investment in Delta House using the cost method of accounting for investments as it does not have the ability to exercise significant influence over such investment. Under the cost method, the Fund recognizes an investment in the equity of an investee at cost. The Fund recognizes as income dividends |

received that are distributed from net accumulated earnings of the investee since the date of acquisition by the Fund. Dividends received in excess of earnings subsequent to the date of investment are considered a return of investment and are recorded as reductions of cost of the investment. The Fund reviews its cost method investment for impairment at each reporting period and when an event or change in circumstances has occurred that may have a significant adverse effect on the fair value of the investment. Losses on cost method investments including impairments that are deemed to be other than temporary are classified as non-operating losses in the Fund's statements of operations.

As of December 31, 2016, the Fund invested a total of $0.6 million in Delta House and has received cash from its investment totaling $0.6 million, of which $0.3 million relates to dividends received and $0.3 million relates to cash proceeds from the sale of approximately 74% of its investment, pursuant to a unit purchase agreement with D-Day Offshore Holdings, LLC dated October 31, 2016. Certain other funds managed by the Manager were also parties to this unit purchase agreement. The Fund adjusted the carrying value of its investment in Delta House in third quarter 2016 to fair value, which was determined based on the third party sale and recorded a loss on investment during the year ended December 31, 2016 of $0.1 million. The loss was included on the Fund's statement of operations within "Loss on investment in Delta House". Inputs used to estimate fair value of the investment in Delta House are categorized as Level 3 in the fair value hierarchy. As of December 31, 2016, the Fund's remaining carrying value for the investment in Delta House was $0.1 million.

Oil and Gas Properties

***Oil and Gas Properties***

The Fund invests in oil and gas properties, which are operated by unaffiliated entities that are responsible for drilling, administering and producing activities pursuant to the terms of the applicable operating agreements with working interest owners. The Fund's portion of exploration, drilling, operating and capital equipment expenditures is billed by operators.

Acquisition, exploration and development costs are accounted for using the successful efforts method. Costs of acquiring unproved and proved oil and natural gas leasehold acreage, including lease bonuses, brokers' fees and other related costs are capitalized. Costs of drilling and equipping productive wells and related production facilities are capitalized. The costs of exploratory wells are capitalized pending determination of whether proved reserves have been found. If proved commercial reserves are not found, exploratory well costs are expensed as dry-hole costs. At times, the Fund receives adjustments to certain wells from their respective operators upon review and audit of the wells' costs. Interest costs related to the Credit Agreement (see Note 3. "Credit Agreement – Beta Project Financing") are capitalized during the period of asset construction. Annual lease rentals and exploration expenses are expensed as incurred. All costs related to production activity, transportation expense and workover efforts are expensed as incurred.

Once a well has been determined to be fully depleted or upon the sale, retirement or abandonment of a property, the cost and related accumulated depletion and amortization, if any, is eliminated from the property accounts, and the resultant gain or loss is recognized.

As of December 31, 2016 and 2015, amounts recorded in due to operators totaling $1.2 million and $0.5 million, respectively, related to capital expenditures for oil and gas properties.

Advances to Operators for Working Interests and Expenditures

***Advances to Operators for Working Interests and Expenditures***

The Fund may be required to advance its share of the estimated succeeding month's expenditures to the operator for its oil and gas properties. As the costs are incurred, the advances are reclassified to proved properties.

Asset Retirement Obligations

***Asset Retirement Obligations***

For oil and gas properties, there are obligations to perform removal and remediation activities when the properties are retired. Upon the determination that a property is either proved or dry, a retirement obligation is incurred. The Fund recognizes the fair value of a liability for an asset retirement obligation in the period incurred. Plug and abandonment costs associated with unsuccessful projects are expensed as dry-hole costs. At least bi-annually, or more frequently if an event occurs that would dictate a change in assumptions or estimates underlying the obligations, the Fund reassesses all of its asset retirement obligations to determine whether any revisions to the obligations are necessary. The following table presents changes in asset retirement obligations during the years ended December 31, 2016 and 2015.

| | 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Balance, beginning of year | $ 3,420 | $ 1,730 |
| Liabilities incurred | 5 | 1,046 |
| Accretion expense | 154 | 94 |
| Revision of estimates | (758) | 550 |
| Balance, end of year | $ 2,821 | $ 3,420 |

As indicated above, the Fund maintains a salvage fund to provide for the funding of future asset retirement obligations.

Syndication Costs

***Syndication Costs***

Syndication costs are direct costs incurred by the Fund in connection with the offering of the Fund's shares, including professional fees, selling expenses and administrative costs payable to the Manager, an affiliate of the Manager and unaffiliated broker-dealers, which are reflected on the Fund's balance sheet as a reduction of shareholders' capital.

Revenue Recognition and Imbalances

***Revenue Recognition and Imbalances***

Oil and gas revenues are recognized when oil and gas is sold to a purchaser at a fixed or determinable price, delivery has occurred and title has transferred, and collectability of the revenue is reasonably assured. The Fund uses the sales method of accounting for gas production imbalances. The volumes of gas sold may differ from the volumes to which the Fund is entitled based on its interests in the properties. These differences create imbalances that are recognized as a liability only when the properties' estimated remaining reserves net to the Fund will not be sufficient to enable the underproduced owner to recoup its entitled share through production. The Fund's recorded liability, if any, would be reflected in other liabilities. No receivables are recorded for those wells where the Fund has taken less than its share of production.

Impairment of Long-Lived Assets

***Impairment of Long-Lived Assets***

The Fund reviews the carrying value of its oil and gas properties annually and when management determines that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. Impairments are determined by comparing estimated future net undiscounted cash flows to the carrying value at the time of the review. If the carrying value exceeds the estimated future net undiscounted cash flows, the carrying value of the asset is written down to fair value, which is determined using estimated future net discounted cash flows from the asset. The fair value determinations require considerable judgment and are sensitive to change. Different pricing assumptions, reserve estimates or discount rates could result in a different calculated impairment. Given the volatility of oil and natural gas prices, it is reasonably possible that the Fund's estimate of discounted future net cash flows from proved oil and natural gas reserves could change in the near term.

Significant and consistent fluctuations in oil and natural gas prices since fourth quarter 2014 have impacted the fair value of the Fund's oil and gas properties. During the year ended December 31, 2016, the Fund recorded impairments of oil and gas properties of $13 thousand, which represented the carrying value of Eugene Island 346/347. The impairments were primarily attributable to declines in future oil and gas prices.

During the year ended December 31, 2015, the Fund recorded impairments of oil and gas properties of $0.3 million related to Eugene Island 346/347 and the Cobalt Project, which were attributable to both declines in future oil and gas prices and revisions to reserve estimates as provided by the Fund's independent petroleum engineers. The fair value of the impaired properties at the date of impairment was $0.1 million.

If oil and natural gas prices decline, even if only for a short period of time, it is possible that additional impairments of oil and gas properties will occur.

Depletion and Amortization

***Depletion and Amortization***

Depletion and amortization of the cost of proved oil and gas properties are calculated using the units-of-production method. Proved developed reserves are used as the base for depleting capitalized costs associated with successful exploratory well costs, development costs and related facilities, other than offshore platforms. The sum of proved developed and proved undeveloped reserves is used as the base for depleting or amortizing leasehold acquisition costs and costs to construct offshore platform and associated asset retirement costs. During the years ended December 31, 2016 and 2015, the Fund recorded $4 thousand and $0.2 million, respectively, of depletion expense related to adjustments to asset retirement obligations for fully depleted properties.

Income Taxes

***Income Taxes***

No provision is made for income taxes in the financial statements. The Fund is a limited liability company, and as such, the Fund's income or loss is passed through and included in the tax returns of the Fund's shareholders. The Fund files U.S. Federal and State tax returns and the 2013 through 2015 tax returns remain open for examination by tax authorities.

Income and Expense Allocation

***Income and Expense Allocation***

Profits and losses are allocated to shareholders and the Manager in accordance with the LLC Agreement.

Distributions

***Distributions***

Distributions to shareholders are allocated in proportion to the number of shares held. The Manager determines whether available cash from operations, as defined in the LLC Agreement, will be distributed. Such distributions are allocated 85% to the shareholders and 15% to the Manager, as required by the LLC Agreement.

Available cash from dispositions, as defined in the LLC Agreement, will be paid 99% to shareholders and 1% to the Manager until the shareholders have received total distributions equal to their capital contributions. After shareholders have received distributions equal to their capital contributions, 85% of available cash from dispositions will be distributed to shareholders and 15% to the Manager.

Recent Accounting Pronouncements

***Recent Accounting Pronouncements***

In January 2016, the Financial Accounting Standards Board ("FASB") issued accounting guidance that requires, among other things, companies to measure investments in other entities, except those accounted for under the equity method, at fair value and recognize any changes in fair value in net income unless an election is made to record the investment at cost, less impairment and plus or minus subsequent adjustments for observable price changes with change in basis reported in current earnings. This pronouncement is effective for fiscal years beginning after December 15, 2017 and interim periods within those fiscal years, with early adoption not permitted. The Fund is currently evaluating the impact of this guidance on its financial statements.

In April 2015, the FASB issued accounting guidance related to the presentation of debt issuance costs on the balance sheet as a direct reduction from the carrying amount of the debt liability, consistent with debt discounts, rather than as an asset. Amortization of debt issuance costs will continue to be reported as interest expense. In August 2015, the FASB issued accounting guidance related to the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements which clarifies that companies may continue to present unamortized debt issuance costs associated with line of credit arrangements as an asset. These pronouncements became effective for fiscal years, and interim periods within those years, beginning after December 15, 2015. The Fund adopted the accounting guidance in first quarter 2016, resulting in a one-time reclassification of $0.7 million of unamortized debt discounts and deferred financing costs from "Other assets" to "Long-term borrowings" on the balance sheet as of December 31, 2015. The adoption of these pronouncements did not impact the Fund's results of operations or cash flows.

In May 2014, the FASB issued accounting guidance on revenue recognition, which provides for a single five-step model to be applied to all revenue contracts with customers. In July 2015, the FASB issued a deferral of the effective date of the guidance to 2018, with early adoption permitted in 2017. In March 2016, the FASB issued accounting guidance, which clarifies the implementation guidance on principal versus agent considerations in the new revenue recognition standard. In April 2016, the FASB issued guidance on identifying performance obligations and licensing and in May 2016, the FASB issued final amendments which provided narrow scope improvements and practical expedients related to the implementation of the guidance. The accounting guidance may be applied either retrospectively or through the use of a modified-retrospective method. Based on the Fund's initial assessment of the accounting guidance, the Fund currently does not expect it will have a material impact on its results of operations or cash flows in the period after adoption. Under the accounting guidance, revenue is recognized as control transfers to the customer, as such the Fund expects the application of the accounting guidance to its existing contracts to be generally consistent with its current revenue recognition model. The Fund will continue the evaluation of the provisions of this accounting guidance, as well as new or emerging interpretations, as it relates to new contracts the Fund receives and in particular as it relates to disclosure requirements through the date of adoption, which is currently expected to be January 1, 2018.

| Organization and Summary of Significant Accounting Policies (Tables) | 12 Months Ended Dec. 31, 2016 |
|---|---|
| **Organization, Consolidation and Presentation of Financial Statements [Abstract]** | |
| Schedule of Changes in Asset Retirement Obligations | |

| | 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Balance, beginning of year | $ 3,420 | $ 1,730 |
| Liabilities incurred | 5 | 1,046 |
| Accretion expense | 154 | 94 |
| Revision of estimates | (758) | 550 |
| Balance, end of year | $ 2,821 | $ 3,420 |

| Information about Oil and Gas Producing Activities (Tables) | 12 Months Ended Dec. 31, 2016 |
|---|---|
| **Information About Oil And Gas Producing Activities [Abstract]** | |
| Schedule of Capitalized Costs Relating to Oil and Gas Producing Activities | **Table I - Capitalized Costs Relating to Oil and Gas Producing Activities** |

| | December 31, 2016 | December 31, 2015 |
|---|---|---|
| | (in thousands) | |
| Proved properties | $ 64,348 | $ 58,004 |
| Total oil and gas properties | 64,348 | 58,004 |
| Accumulated depletion and amortization | (22,242) | (18,310) |
| Oil and gas properties, net | $ 42,106 | $ 39,694 |

Schedule of Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development

**Table II - Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development**

| | Year ended December 31, 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Exploration costs | $ 64 | $ 14 |
| Development costs | 6,163 | 14,719 |
| | $ 6,227 | $ 14,733 |

Schedule of Reserve Quantity Information

**Table III - Reserve Quantity Information**

Oil and gas reserves of the Fund have been estimated by independent petroleum engineers, Netherland, Sewell & Associates, Inc. at December 31, 2016 and 2015. These reserve disclosures have been prepared in compliance with the Securities and Exchange Commission rules. Due to inherent uncertainties and the limited nature of recovery data, estimates of reserve information are subject to change as additional information becomes available.

| | December 31, 2016 | | | December 31, 2015 | | |
|---|---|---|---|---|---|---|
| | United States | | | | | |
| | Oil (BBLS) | NGL (BBLS) | Gas (MCF) | Oil (BBLS) | NGL (BBLS) | Gas (MCF) |
| **Proved developed and undeveloped reserves:** | | | | | | |
| Beginning of year | 1,284,623 | 109,756 | 1,940,204 | 1,214,454 | 34,268 | 2,303,413 |
| Revisions of previous estimates (a) | (254,807) | 86,972 | 84,834 | 139,275 | 89,265 | (163,848) |
| Production | (142,016) | (13,898) | (279,288) | (69,106) | (13,777) | (199,361) |
| End of year | 887,800 | 182,830 | 1,745,750 | 1,284,623 | 109,756 | 1,940,204 |
| **Proved developed reserves:** | | | | | | |
| Beginning of year | 382,074 | 64,613 | 970,446 | 40,373 | 34,268 | 608,088 |
| End of year | 726,811 | 115,780 | 1,229,330 | 382,074 | 64,613 | 970,446 |
| **Proved undeveloped reserves:** | | | | | | |
| Beginning of year | 902,549 | 45,143 | 969,758 | 1,174,081 | - | 1,695,325 |
| End of year | 160,989 | 67,050 | 516,420 | 902,549 | 45,143 | 969,758 |

(a) Revisions of previous estimates were attributable to well performance.

Schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

**Table IV - Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves**

Summarized in the following table is information for the Fund with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows were determined based on average first-of-the-month pricing for the prior twelve month period. Future production and development costs are derived based on current costs assuming continuation of existing economic conditions.

| | December 31, 2016 | 2015 |
|---|---|---|
| | (in thousands) | |

| | | |
|---|---|---|
| Future cash inflows | $ 38,457 | $ 66,145 |
| Future production costs | (13,555) | (16,390) |
| Future development costs | (9,218) | (20,044) |
| Future net cash flows | 15,684 | 29,711 |
| 10% annual discount for estimated timing of cash flows | (1,172) | (8,381) |
| Standardized measure of discounted future net cash flows | $ 14,512 | $ 21,330 |

Schedule of Changes in the Standardized Measure for Discounted Cash Flows

**Table V - Changes in the Standardized Measure for Discounted Cash Flows**

The changes in present values between years, which can be significant, reflect changes in estimated proved reserve quantities and prices and assumptions used in forecasting production volumes and costs.

| | Year ended December 31, 2016 | 2015 |
|---|---|---|
| | (in thousands) | |
| Net change in sales and transfer prices and in production costs related to future production | $ (13,465) | $ (37,873) |
| Sales and transfers of oil and gas produced during the period | (3,323) | (1,594) |
| Changes in estimated future development costs | 10,826 | 6,070 |
| Net change due to revisions in quantities estimates | (2,601) | 4,185 |
| Accretion of discount | 2,133 | 5,079 |
| Other | (388) | (5,322) |
| Aggregate change in the standardized measure of discounted future net cash flows for the year | $ (6,818) | $ (29,455) |

| Organization and Summary of Significant Accounting Policies (Narrative) (Details) - USD ($) $ in Thousands | 12 Months Ended | |
|---|---|---|
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Organization and Summary of Significant Accounting Policies [Abstract]** | | |
| Maximum cash balance federally insured per financial institution | $ 250 | |
| Cash proceeds from sale of investment in Delta House | 339 | |
| Loss on investment in Delta House | (114) | |
| Investment in Delta House | 119 | 572 |
| Value of capital expenditures for oil and gas properties owed to operators | 1,200 | 500 |
| Impairment of oil and gas properties | 13 | 266 |
| Depletion | $ 4 | 200 |
| Percentage of cash from operations allocated to shareholders | 85.00% | |
| Percentage of cash from operations allocated to fund manager | 15.00% | |
| Percentage of available cash from dispositions allocated to shareholders | 99.00% | |
| Percentage of available cash from dispositions allocated to fund manager | 1.00% | |
| Percentage of available cash from dispositions allocated to shareholders after distributions have equaled capital contributions | 85.00% | |
| Percentage of available cash from dispositions allocated to fund manager after distributions have equaled capital contributions | 15.00% | |
| Reclassification of unamortized debt discounts and deferred financing costs | $ 700 | |
| Eugene Island 346/347 [Member] | | |
| **Organization and Summary of Significant Accounting Policies [Abstract]** | | |
| Impairment of oil and gas properties | 13 | |
| Eugene Island 346/347 And Cobalt Project [Member] | | |
| **Organization and Summary of Significant Accounting Policies [Abstract]** | | |
| Impairment of oil and gas properties | | 266 |
| Oil and gas properties, fair value | | $ 100 |
| Delta House [Member] | | |
| **Organization and Summary of Significant Accounting Policies [Abstract]** | | |
| Total investment in Delta House | 600 | |
| Dividends on investment in Delta House | 300 | |
| Cash proceeds from sale of investment in Delta House | $ 339 | |
| Ownership percentage prior to sale | 74.00% | |

| Organization and Summary of Significant Accounting Policies (Schedule of Changes in Asset Retirement Obligations) (Details) - USD ($) $ in Thousands | 12 Months Ended | |
|---|---|---|
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Organization, Consolidation and Presentation of Financial Statements [Abstract]** | | |
| Balance, beginning of year | $ 3,420 | $ 1,730 |
| Liabilities incurred | 5 | 1,046 |
| Accretion expense | 154 | 94 |
| Revision of estimates | (758) | 550 |
| Balance, end of year | $ 2,821 | $ 3,420 |

| Related Parties (Details) - USD ($) $ in Thousands | 12 Months Ended | |
| --- | --- | --- |
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Related Party Transaction [Line Items]** | | |
| Annual management fee percentage rate | 2.50% | |
| Annual management fees paid to Fund Manager | $ 1,282 | $ 1,399 |
| Percentage of total distributions allocated to Fund Manager | 15.00% | |
| Distributions | | (177) |
| Manager [Member] | | |
| **Related Party Transaction [Line Items]** | | |
| Distributions | | $ (27) |

| Credit Agreement - Beta Project Financing (Details) - USD ($) $ in Thousands | 12 Months Ended | |
|---|---|---|
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Debt Disclosure [Abstract]** | | |
| Credit agreement, maximum borrowing capacity | $ 24,100 | |
| Long-term borrowings | $ 24,100 | $ 22,800 |
| Credit agreement, interest rate | 8.00% | |
| Credit agreement, contingency repayment rate, first seven months of production | 1.25% | |
| Credit agreement, contingency repayment rate, after first seven months of production | 4.50% | |
| Credit agreement, maturity date | Dec. 31, 2020 | |
| Unamortized debt discounts and deferred financing costs | $ 400 | 700 |
| Accumulated amortization | 200 | 400 |
| Amortization of financing costs | 200 | |
| Capitalized interest | 2,200 | $ 1,300 |
| Interest expense | 1,000 | |
| Interest paid | $ 300 | |

| Commitments and Contingencies (Details)<br>$ in Thousands | 12 Months Ended<br>Dec. 31, 2016<br>USD ($) |
|---|---|
| **Commitments and Contingencies Disclosure [Abstract]** | |
| Commitments for the drilling and development of investment properties | $ 15,700 |
| Commitments for asset retirement obligations included in estimated capital commitments | 5,900 |
| Commitments for the drilling and development of investment properties expected to be incurred in the next 12 months | $ 5,500 |

| Information about Oil and Gas Producing Activities (Schedule of Capitalized Costs Relating to Oil and Gas Producing Activities) (Details) - USD ($) $ in Thousands | Dec. 31, 2016 | Dec. 31, 2015 |
|---|---|---|
| **Information About Oil And Gas Producing Activities [Abstract]** | | |
| Proved properties | $ 64,348 | $ 58,004 |
| Total oil and gas properties | 64,348 | 58,004 |
| Accumulated depletion and amortization | (22,242) | (18,310) |
| Total oil and gas properties, net | $ 42,106 | $ 39,694 |

| Information about Oil and Gas Producing Activities (Schedule of Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development) (Details) - USD ($) $ in Thousands | 12 Months Ended | |
|---|---|---|
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Information About Oil And Gas Producing Activities [Abstract]** | | |
| Exploration costs | $ 64 | $ 14 |
| Development costs | 6,163 | 14,719 |
| Total costs | $ 6,227 | $ 14,733 |

| Information about Oil and Gas Producing Activities (Schedule of Reserve Quantity Information) (Details) | | 12 Months Ended | |
|---|---|---|---|
| | | Dec. 31, 2016 bbl Mcf | Dec. 31, 2015 bbl Mcf |
| Oil (BBLS) [Member] | | | |
| **Proved developed and undeveloped reserves:** | | | |
| Beginning of year | | 1,284,623 | 1,214,454 |
| Revisions of previous estimates | [1] | (254,807) | 139,275 |
| Production | | (142,016) | (69,106) |
| End of year | | 887,800 | 1,284,623 |
| **Proved developed reserves:** | | | |
| Beginning of year | | 382,074 | 40,373 |
| End of year | | 726,811 | 382,074 |
| **Proved undeveloped reserves:** | | | |
| Beginning of year | | 902,549 | 1,174,081 |
| End of year | | 160,989 | 902,549 |
| NGL (BBLS) [Member] | | | |
| **Proved developed and undeveloped reserves:** | | | |
| Beginning of year | | 109,756 | 34,268 |
| Revisions of previous estimates | [1] | 86,972 | 89,265 |
| Production | | (13,898) | (13,777) |
| End of year | | 182,830 | 109,756 |
| **Proved developed reserves:** | | | |
| Beginning of year | | 64,613 | 34,268 |
| End of year | | 115,780 | 64,613 |
| **Proved undeveloped reserves:** | | | |
| Beginning of year | | 45,143 | |
| End of year | | 67,050 | 45,143 |
| Gas (MCF) [Member] | | | |
| **Proved developed and undeveloped reserves:** | | | |
| Beginning of year \| Mcf | | 1,940,204 | 2,303,413 |
| Revisions of previous estimates \| Mcf | [1] | 84,834 | (163,848) |
| Production \| Mcf | | (279,288) | (199,361) |
| End of year \| Mcf | | 1,745,750 | 1,940,204 |
| **Proved developed reserves:** | | | |
| Beginning of year \| Mcf | | 970,446 | 608,088 |
| End of year \| Mcf | | 1,229,330 | 970,446 |
| **Proved undeveloped reserves:** | | | |
| Beginning of year \| Mcf | | 969,758 | 1,695,325 |
| End of year \| Mcf | | 516,420 | 969,758 |

[1] Revisions of previous estimates were attributable to well performance.

| Information about Oil and Gas Producing Activities (Schedule of Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves) (Details) - USD ($) $ in Thousands | Dec. 31, 2016 | Dec. 31, 2015 |
|---|---|---|
| **Information About Oil And Gas Producing Activities [Abstract]** | | |
| Future cash inflows | $ 38,457 | $ 66,145 |
| Future production costs | (13,555) | (16,390) |
| Future development costs | (9,218) | (20,044) |
| Future net cash flows | 15,684 | 29,711 |
| 10% annual discount for estimated timing of cash flows | (1,172) | (8,381) |
| Standardized measure of discounted future net cash flows | $ 14,512 | $ 21,330 |

| Information about Oil and Gas Producing Activities (Schedule of Changes in the Standardized Measure for Discounted Cash Flows) (Details) - USD ($) $ in Thousands | 12 Months Ended | |
|---|---|---|
| | Dec. 31, 2016 | Dec. 31, 2015 |
| **Information About Oil And Gas Producing Activities [Abstract]** | | |
| Net change in sales and transfer prices and in production costs related to future production | $ (13,465) | $ (37,873) |
| Sales and transfers of oil and gas produced during the period | (3,323) | (1,594) |
| Changes in estimated future development costs | 10,826 | 6,070 |
| Net change due to revisions in quantities estimates | (2,601) | 4,185 |
| Accretion of discount | 2,133 | 5,079 |
| Other | (388) | (5,322) |
| Aggregate change in the standardized measure of discounted future net cash flows for the year | $ (6,818) | $ (29,455) |