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, 2017** Commission File No. **0-22750**

ROYALE ENERGY FUNDS, INC.
(Name of registrant in its charter)

California	**33-0224120**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1870 Cordell Court
El Cajon, CA 92020
(Address of principal executive offices)

Issuer's telephone number: **619-383-6600**

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

Securities to be registered pursuant to Section 12(g) of the Act:
Common Stock, no par value per share
(Title of Class)

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 during the past 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 disclosure of delinquent filers pursuant to Item 405 of Regulation S-B is not contained herein, and will not be contained, to the best or 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 large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See definition of "large accelerated filer," accelerated filer" "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act:

Large accelerated filer ☐	Accelerated filer ☐
Non-accelerated filer ☐	Smaller Reporting Company ☒
Emerging growth company ☐	

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

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

At June 30, 2017, the end of the registrant's most recently completed second fiscal quarter; the aggregate market value of common equity held by non-affiliates was $7,161,166.

At February 27, 2018, 21,850,185 shares of registrant's Common Stock were outstanding.

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ROYALE ENERGY FUNDS, INC.

PART I

Item 1 Description of Business

Royale Energy Funds, Inc. ("Royale" or the "Company") is an independent oil and natural gas producer incorporated under the laws of California. Royale's principal lines of business are the production and sale of natural gas, acquisition of oil and gas lease interests and proved reserves, drilling of both exploratory and development wells, and sales of fractional working interests in wells to be drilled by Royale. Royale was incorporated in California in 1986 and began operations in 1988. On December 31, 2017, Royale had 11 full time employees.

Merger with Matrix Oil Management Corporation

On March 7, 2018, Royale Energy Holdings, Inc. ("New Royale"), Royale, and Matrix Oil Management Corporation ("Matrix") and its affiliates were notified by the California Secretary of State of the filing and acceptance of agreements of merger by the California Secretary of State, to complete the previously announced merger between the companies (the "Merger"). In the Merger, Royale was merged into a newly formed subsidiary of New Royale, and Matrix was merged into a second newly formed subsidiary of New Royale pursuant to the Amended and Restated Agreement and Plan of Merger among Royale, New Royale, Royale Merger Sub, Inc., ("Royale Merger Sub"), Matrix Merger Sub, Inc., ("Matrix Merger Sub") and Matrix (the "Merger Agreement"). Additionally, in connection with the merger, all limited partnership interest of two limited partnership affiliates of Matrix (Matrix Permian Investments, LP, and Matrix Las Cienegas Limited Partnership), were exchanged for New Royale common stock using conversion ratios according to the relative values of each partnership. All Class A limited partnership interests of another Matrix affiliate, Matrix Investments, LP ("Matrix Investments") were exchanged for New Royale Common stock using conversion ratios according to the relative value of the Class A limited partnership interests, and $20,124,000 of Matrix Investments preferred limited partnership interests were converted into 2,012,400 shares of Series B Convertible Preferred Stock of New Royale. Another Matrix affiliate, Matrix Oil Corporation ("Matrix Operator"), was acquired by New Royale by exchanging New Royale common stock for the outstanding common stock of Matrix Oil Corporation using a conversion ratio according to the relative value of the Matrix Oil Corporation common stock. Matrix, Matrix Oil Corporation and the three limited partnership affiliates of Matrix called the "Matrix Entities."

The Merger had been previously approved by the respective holders of all outstanding capital stock of Royale, Matrix, New Royale, Matrix Merger Sub and Royale Merger Sub on November 16, 2017, as previously reported in our Current Report on Form 8-K dated November 16, 2017. The Merger and related transactions are described in detail in our Current Report on Form 8-K dated March 7, 2018, and in New Royale's Current Report on Form 8-K dated March 7, 2018 (SEC File No. 000-55912).

As a result of the Merger, Royale became a wholly owned subsidiary of New Royale, and each outstanding share common stock of Royale at the time of the Merger was converted into one share of common stock of New Royale. The common stock of New Royale is traded on the Over-The-Counter QB (OTCQB) Market System (symbol ROYL).

In this Annual Report, "Royale" and the "Company" refer to Royale Energy Funds, Inc., the California corporation formerly known as Royale Energy, Inc. In connection with the Merger, the California Articles of Incorporation of Royale Energy, Inc., was amended to change the name of the Company to Royale Energy Funds, Inc. This Annual Report describes the business and affairs of Royale, prior to the Merger, for the year ended December 31, 2017.

Royale Energy Funds, Inc.

Royale owns wells and leases located mainly in the Sacramento Basin and San Joaquin Basin in California as well as in Utah, Texas, Oklahoma, and Louisiana. Royale usually sells a portion of the working interest in each well it drills or participates in to third party investors and retains a portion of the prospect for its own account. Selling part of the working interest to others allows Royale to reduce its drilling risk by owning a diversified inventory of properties with less of its own funds invested in each drilling prospect, than if Royale owned all the working interest and paid all drilling and development costs of each prospect itself. Royale generally sells working interests in its prospects to accredited investors in exempt securities offerings. The prospects are bundled into multi-well investments, which permit the third party investors to diversify their investments by investing in several wells at once instead of investing in single well prospects.

During its fiscal year ended December 31, 2017, Royale continued to explore and develop natural gas properties with a concentration in California. Additionally, we own proved developed producing and non-producing reserves of oil and natural gas in Utah, Texas, Oklahoma and Louisiana, as well as holding an overriding royalty interest in a discovery in Alaska. In 2017, Royale drilled three natural gas wells in northern California, two of which were commercially productive, and participated in the drilling of an additional oil well in the Sansinena field in Los Angeles County, which was commercially productive. Royale's estimated total reserves were approximately 2.1 and 2.1 BCFE (billion cubic feet equivalent) at December 31, 2017 and 2016, respectively. According to the reserve reports furnished by Netherland, Sewell & Associates, Inc., Royale's independent petroleum engineers, the undiscounted net reserve value of its proved developed and undeveloped reserves was approximately $3.4 million at December 31, 2017, based on the natural gas average PG&E city-gate spot price of $3.26 per MCF. Netherland, Sewell & Associates, Inc. supplied reserve value estimates for the Company's California, Texas, Oklahoma, Utah and Louisiana properties.

Of course, net reserve value does not represent the fair market value of our reserves on that date, and we cannot be sure what return we will eventually receive on our reserves. Net reserve value of proved developed and undeveloped reserves was calculated by subtracting estimated future development costs, future production costs and other operating expenses from estimated net future cash flows from our developed and undeveloped reserves.

Our standardized measure of discounted future net cash flows at December 31, 2017, was estimated to be $1,644,688. This figure was calculated by subtracting our estimated future income tax expense from the net reserve value of proved developed and undeveloped reserves, and by further applying a 10% annual discount for estimated timing of cash flows. A detailed calculation of our standardized measure of discounted future net cash flow is contained in Supplemental Information about Oil and Gas Producing Activities – Changes in Standardized Measure of Discounted Future Net Cash Flow from Proved Reserve Quantities, page F-24.

Royale reported a gain on turnkey drilling in connection with the drilling of wells on a "turnkey contract" basis in the amount of $1,487,824 and $460,210 for the years ended December 31, 2017 and 2016, respectively.

In addition to Royale's own staff, Royale hires independent contractors to drill, test, complete and equip the wells that it drills. Approximately 55.0% of Royale's total revenue for the year ended December 31, 2017, came from sales of oil and natural gas from production of its wells in the amount of $554,235. In 2016, this amount was $538,631, which represented 44.4% of Royale's total revenues.

Plan of Business

Royale acquires interests in oil and natural gas reserves and sponsors private joint ventures. Royale believes that its stockholders are better served by diversification of its investments among individual drilling prospects. Through its sale of joint ventures, Royale can acquire interests and develop oil and natural gas properties with greater diversification of risk and still receive an interest in the revenues and reserves produced from these properties. By selling some of its working interest in most projects, Royale decreases the amount of its investment in the projects and diversifies its oil and gas property holdings, to reduce the risk of concentrating a large amount of its capital in a few projects that may not be successful.

After acquiring the leases or lease participation, Royale drills or participates in the drilling of development and exploratory oil and natural gas wells on its property. Royale pays its proportionate share of the actual cost of drilling, testing, and completing the project to the extent that it retains all or any portion of the working interest.

Royale also may sell fractional working interests in undeveloped wells to finance part of the drilling cost. A drilling contract that calls for a company to drill a well, for a fixed price, to a specified depth or geological formation is called a "turnkey contract." When Royale sells fractional working interests in unproved property to raise capital to drill oil and natural gas wells, generally it agrees to drill these wells on a turnkey contract basis, so that the holders of the fractional interests prepay a fixed amount for the drilling and completion of a specified number of wells. Under a turnkey contract, Royale may record a gain if total funds received to drill a well were more than the actual cost to drill those wells including costs incurred on behalf of the participants and costs incurred for its own account.

Although Royale's operating agreements do not usually address whether investors have a right to participate in subsequent wells in the same area of interest as a proposed well, it is the Company's policy to offer to investors in a successful well the right to participate in subsequent wells at the same percentage level as their working interest investment in the prior successful well.

Our policy for turnkey drilling agreements is to recognize a gain on turnkey drilling programs after our obligations have been fulfilled, and a gain is only recorded when funds received from participants are in excess of all costs Royale incurs during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for its own account. See Note 1 to our Financial Statements, at page F-8.

Once drilling has commenced, it is generally completed within 10-30 days. See Note 1 to Royale's Financial Statements, at page F-8. Royale maintains internal records of the expenditure of each investor's funds for drilling projects.

Royale generally operates the wells it completes. As operator, it receives fees set by industry standards from the owners of fractional interests in the wells and from expense reimbursements. For the year ended December 31, 2017, Royale earned gross revenues from operation of the wells in the amount of $197,020 representing 19.6% of its total revenues for the year. In 2016, the amount was $406,560, which represented about 33.5% of total revenues. At December 31, 2017, Royale operated 24 natural gas wells in California. Royale also has non-operating interests in seven oil and gas wells in California, three natural gas wells in Utah, four oil and gas wells in Texas, two in Oklahoma and one in Louisiana.

Royale currently sells most of its California natural gas production through PG&E pipelines to independent customers on a monthly contract basis, while some gas is delivered through privately owned pipelines to independent customers. Since many users are willing to make such purchase arrangements, the loss of any one customer would not affect our overall sales operations.

All oil and natural gas properties are depleting assets in which production naturally decreases over time as the finite amount of existing reserves are produced and sold. It is Royale's business as an oil and natural gas exploration and production company to continually search for new development properties. The Company's success will ultimately depend on its ability to continue locating and developing new oil and natural gas resources. Natural gas demand and the prices paid for gas are seasonal. In recent years, natural gas demand and prices in Northern California have fluctuated unpredictably throughout the year.

In 2017, Royale had one wholly owned subsidiary, Royale DWI Investors, LLC, a California limited liability company, to hold legal title to certain oil and gas working interests which Royale owns for the benefit of its working interest investors.

Competition, Markets and Regulation

Competition

The exploration and production of oil and natural gas is an intensely competitive industry. The sale of interests in oil and gas projects, like those Royale sells, is also very competitive. Royale encounters competition from other oil and natural gas producers, as well as from other entities that invest in oil and gas for their own account or for others, and many of these companies are substantially larger than Royale.

Markets

Market factors affect the quantities of oil and natural gas production and the price Royale can obtain for the production from its oil and natural gas properties. Such factors include: the extent of domestic production; the level of imports of foreign oil and natural gas; the general level of market demand on a regional, national and worldwide basis; domestic and foreign economic conditions that determine levels of industrial production; political events in foreign oil-producing regions; and variations in governmental regulations including environmental, energy conservation, and tax laws or the imposition of new regulatory requirements upon the oil and natural gas industry.

Regulation

Federal and state laws and regulations affect, to some degree, the production, transportation, and sale of oil and natural gas from Royale's operations. States in which Royale operates have statutory provisions regulating the production and sale of oil and natural gas, including provisions regarding deliverability. These statutes, along with the regulations interpreting the statutes, generally are intended to prevent waste of oil and natural gas, and to protect correlative rights to produce oil and natural gas by assigning allowable rates of production to each well or proration unit.

The exploration, development, production and processing of oil and natural gas are subject to various federal and state laws and regulations to protect the environment. Various federal and state agencies are considering, and some have adopted, other laws and regulations regarding environmental controls that could increase the cost of doing business. These laws and regulations may require: the acquisition of permits by operators before drilling commences; the prohibition of drilling activities on certain lands lying within wilderness areas or where pollution arises; and the imposition of substantial liabilities for pollution resulting from drilling operations, particularly operations in offshore waters or on submerged lands. The cost of oil and natural gas development and production also may increase because of the cost of compliance with such legislation and regulations, together with any penalties resulting from failing to comply with the legislation and regulations. Ultimately, Royale may bear some of these costs.

Presently, Royale does not anticipate that compliance with federal, state and local environmental regulations will have a material adverse effect on capital expenditures, earnings, or its competitive position in the oil and natural gas industry; however, changes in the laws, rules or regulations, or the interpretation thereof, could have a materially adverse effect on Royale's financial condition or results of operation.

Royale has filed quarterly, yearly and other reports with the Securities Exchange Commission, and New Royale will continue filing these reports as Royale's successor in interest. You may obtain a copy of any materials filed by Royale with the SEC at 100 F Street, N.W., Washington, D.C. 20549, by calling 1-800-SEC-0300. The SEC also maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Royale also provides access to its SEC reports and other public announcements on its website, http://www.royl.com.

Item 2 Description of Property

Since 1993, Royale has concentrated on development of properties in the Sacramento Basin and the San Joaquin Basin of Northern and Central California. In 2017, Royale drilled three developmental natural gas wells in northern California, and participated in the drilling of a developmental oil well in Los Angeles County, California.

Following industry standards, Royale generally acquires oil and natural gas acreage without warranty of title except as to claims made by, though, or under the transferor. In these cases, Royale attempts to conduct due diligence as to title before the acquisition, but it cannot assure that there will be no losses resulting from title defects or from defects in the assignment of leasehold rights. Title to property most often carries encumbrances, such as royalties, overriding royalties, carried and other similar interests, and contractual obligations, all of which are customary within the oil and natural gas industry.

Following is a discussion of Royale's significant oil and natural gas properties. Reserves at December 31, 2017, for each property discussed below, have been determined by Netherland, Sewell & Associates, Inc., registered professional petroleum engineers, in accordance with reports submitted to Royale on February 14, 2018.

Northern California

Royale owns lease interests in nine gas fields with locations ranging from Glenn County in the north to Madera County in the south, in the Sacramento Basin in California. At December 31, 2017, Royale operated 24 wells in California with estimated total proven, developed, and undeveloped reserves at approximately 2.1 BCF, according to Royale's independently prepared reserve report as of December 31, 2017.

Developed and Undeveloped Leasehold Acreage

As of December 31, 2017, Royale owned leasehold interests in the following developed and undeveloped properties in both gross and net acreage.

	Developed		Undeveloped	
	Gross Acres	Net Acres	Gross Acres	Net Acres
California	5,092.76	3,778.97	11,432.00	3,308.42
All Other States	2,947.89	1,600.78	7,121.00	6,609.00
Total	8,040.65	5,379.74	18,553.00	9,917.42

Gross and Net Productive Wells

As of December 31, 2017, Royale owned interests in the following oil and gas wells in both gross and net acreage:

	Gross Wells	Net Wells
Natural Gas	36.00	15.36
Oil	5.00	.26
Total	41.00	15.62

Drilling Activities

The following table sets forth Royale's drilling activities during the years ended December 31, 2016 and 2017. All wells are located in the Continental U.S., in California, Texas, Louisiana and Utah.

Year	Type of Well(a)	Total	Gross Wells(b) Producing(c)	Gross Wells(b) Dry(d)	Net Wells(e) Producing(c)	Net Wells(e) Dry(d)
2016	Exploratory	2	2	-	0.3613	-
	Developmental	1	1	-	0.2097	-
2017	Exploratory	-	-	-	-	-
	Developmental	4	3	1	0.0028	0.0000

a) An exploratory well is one that is drilled in search of new oil and natural gas reservoirs, or to test the boundary limits of a previously discovered reservoir. A developmental well is one drilled on a previously known productive area of an oil and natural gas reservoir with the objective of completing that reservoir.

b) Gross wells represent the number of actual wells in which Royale owns an interest. Royale's interest in these wells may range from 1% to 100%.

c) A producing well is one that produces oil and/or natural gas that is being purchased on the market.

d) A dry well is a well that is not deemed capable of producing hydrocarbons in paying quantities.

e) One "net well" is deemed to exist when the sum of fractional ownership working interests in gross wells or acres equals one. The number of net wells is the sum of the fractional working interests owned in gross wells expressed as a whole number or a fraction.

Production

The following table summarizes, for the periods indicated, Royale's net share of oil and natural gas production, average sales price per barrel (BBL), per thousand cubic feet (MCF) of natural gas, and the MCF equivalent (MCFE) for the barrels of oil based on a 6 to 1 ratio of the price per barrel of oil to the price per MCF of natural gas. "Net" production is production that Royale owns either directly or indirectly through partnership or joint venture interests produced to its interest after deducting royalty, limited partner or other similar interests. Royale generally sells its oil and natural gas at prices then prevailing on the "spot market" and does not have any material long term contracts for the sale of natural gas at a fixed price.

	2017	2016
Net volume		
Oil (BBL)	102	193
Gas (MCF)	190,111	232,539
MCFE	190,723	233,697
Average sales price		
Oil (BBL)	$ 46.07	$ 12.11
Gas (MCF)	$ 2.89	$ 2.31
Net production costs and taxes	$ 435,637	$ 594,241
Lifting costs (per MCFE)	$ 2.28	$ 2.54

Net Proved Oil and Natural Gas Reserves

As of December 31, 2017, Royale had proved developed reserves of 1,799 MMCF and total proved reserves of 2,132 MMCF of natural gas on all of the properties Royale leases. For the same period, Royale also had proved developed oil and natural gas liquid combined reserves of 0.2 MBBL and total proved oil and natural gas liquid combined reserves of 0.2 MBBL.

Oil and gas reserve estimates and the discounted present value estimates associated with the reserve estimates are based on numerous engineering, geological and operational assumptions that generally are derived from limited data.

Item 3 Defaults Upon Senior Securities

On August 2, 2016, the Company issued two unsecured convertible promissory notes for a total principal amount of $1,580,000 to two investors. *See Capital Resources and Liquidity, page 12.* On August 2, 2017, the notes became due and payable and remained due and payable on December 31, 2017. On February 28, 2018, one of the notes, for $300,000, was converted to 750,000 shares of common stock immediately prior to the Merger (a conversion price of $0.40 per share). Also on February 28, 2018, Royale reached a settlement of a dispute with the second investor regarding his advance of $1.28 million. In the settlement, Royale has agreed to pay $1.9 million to the investor, who in turn did not receive shares of the Company's common stock on conversion of this investment. In the settlement, Royale also cancelled a two year warrant issued to the second investor to purchase 1,066,667 of Royale common stock at $0.80 per share.

Item 4 Mine Safety Disclosures

Not Applicable

PART II

Item 5 Market for Common Equity and Related Stockholder Matters

Royale's Common Stock is traded under the symbol "ROYL". Since January 21, 2016, Royale's Common Stock has been traded on the OTC QB Market. Prior to that, Royale's Common Stock was traded on the Nasdaq Stock Market. As of December 31, 2017, 21,850,185 shares of Royale's Common Stock were held by approximately 4,928 stockholders. The following table reflects the high and low quarterly closing sales prices on the Nasdaq Stock Market and OTC QB Market from January 2016 through December 2017.

	1st Qtr		2nd Qtr		3rd Qtr		4th Qtr	
	High	Low	High	Low	High	Low	High	Low
2016	0.57	0.07	0.47	0.34	0.80	0.43	0.74	0.58
2017	0.65	0.50	0.50	0.32	0.44	0.33	0.45	0.34

Dividends

The Board of Directors did not issue cash or stock dividends in 2017 or 2016.

Recent Sales of Unregistered Securities

None.

Item 6 Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with Royale's Financial Statements and Notes thereto and other financial information relating to Royale included elsewhere in this document.

Since 1993, Royale has primarily acquired and developed producing and non-producing natural gas properties in California. In 2004, Royale began developing leases in Utah and in 2012 began acquiring leases in Alaska. The most significant factors affecting the results of operations are (i) the change in commodities price of natural gas and oil reserves owned by Royale, (ii) changes in oil and natural gas production levels and reserves, and (iii) turnkey drilling activities and (iv) the impairment of our Alaska leases.

Merger with Matrix Oil Management Corporation

On March 7, 2018, New Royale, Royale, and Matrix and its affiliates were notified by the California Secretary of State of the filing and acceptance of agreements of merger by the California Secretary of State, to complete the previously announced merger between the companies (the "Merger"), as described in *Item 1 – Description of Business – Merger with Matrix Oil Management Corporation*.

Critical Accounting Policies

<u>Revenue Recognition</u>

Royale's primary business is oil and gas production. Natural gas flows from the wells into gathering line systems, which are equipped occasionally with compressor systems, which in turn flow into metered transportation and customer pipelines. Monthly, price data and daily production are used to invoice customers for amounts due to Royale and other working interest owners. Royale operates most of its own wells and receives industry standard operator fees.

Royale generally sells crude oil and natural gas under short-term agreements at prevailing market prices. Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured.

Revenues from the production of oil and natural gas properties in which the Royale has an interest with other producers are recognized on the basis of Royale's net working interest. Differences between actual production and net working interest volumes are not significant.

Royale's financial statements include its *pro rata* ownership of wells. Royale usually sells a portion of the working interest in each well it drills or participates in to third party investors and retains a portion of the prospect for its own account. Royale generally retains about a 50% working interest. All results, successful or not, are included at its pro rata ownership amounts: revenue, expenses, assets, and liabilities as defined in FASB ASC 932-323-25 and 932-360.

Oil and Gas Property and Equipment

Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Interest costs, to the extent they are incurred to finance expenditures during the construction phase, are included in property, plant and equipment and are depreciated over the service life of the related assets.

Royale uses the “successful efforts” method to account for its exploration and production activities. Under this method, Royale accumulates its proportionate share of costs on a well-by-well basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred, and capitalizes expenditures for productive wells. Royale amortizes the costs of productive wells under the unit-of-production method.

Royale carries, as an asset, exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where Royale is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain Royale’s wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity. Proved oil and gas properties held and used by Royale are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

Royale estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated evaluation assumptions for crude oil commodity prices. Annual volumes are based on field production profiles, which are also updated annually. Prices for natural gas and other products are based on assumptions developed annually for evaluation purposes.

Impairment analyses are generally based on proved reserves. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value. During 2017 and 2016, impairment losses of $289,775 and $2,071,849, respectively, were recorded on various capitalized lease and land costs where the carrying value exceeded the fair value or where the leases were no longer viable.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that Royale expects to hold the properties. The valuation allowances are reviewed at least annually.

Upon the sale or retirement of a complete field of a proved property, Royale eliminates the cost from its books, and the resultant gain or loss is recorded to Royale’s Statement of Operations. Upon the sale of an entire interest in an unproved property where the property has been assessed for impairment individually, a gain or loss is recognized in Royale’s Statement of Operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a recovery of the cost in the interest retained with any excess funds recognized as a gain. Should Royale’s turnkey drilling agreements include unproved property, total drilling costs incurred to satisfy its obligations are recovered by the total funds received under the agreements. Any excess funds are recorded as a Gain on Turnkey Drilling Programs, and any costs not recovered are capitalized and accounted for under the “successful efforts” method.

Royale sponsors turnkey drilling agreement arrangements in unproved properties as a pooling of assets in a joint undertaking, whereby proceeds from participants are reported as Deferred Drilling Obligations, and then reduced as costs to complete its obligations are incurred with any excess booked against its property account to reduce any basis in its own interest. Gains on Turnkey Drilling Programs represent funds received from turnkey drilling participants in excess of all costs Royale incurs during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for its own account; and are recognized only upon making this determination after Royale's obligations have been fulfilled.

The contracts require the participants pay Royale the full contract price upon execution of the agreement. Royale completes the drilling activities typically between 10 and 30 days after drilling begins. The participant retains an undivided or proportional beneficial interest in the property, and is also responsible for its proportionate share of operating costs. Royale retains legal title to the lease. The participants purchase a working interest directly in the well bore.

In these working interest arrangements, the participants are responsible for sharing in the risk of development, but also sharing in a proportional interest in rights to revenues and proportional liability for the cost of operations after drilling is completed.

Since the participant's interest in the prospect is limited to the well, and not the lease, the investor does not have a legal right to participate in additional wells drilled within the same lease. However, it is the Company's policy to offer to participants in a successful well the right to participate in subsequent wells at the same percentage level as their working interest investment in the prior successful well with similar turnkey drilling agreement terms.

A certain portion of the turnkey drilling participant's funds received are non-refundable. The company records a liability for all funds invested as deferred drilling obligations until each individual well is complete. Occasionally, drilling is delayed for various reasons such as weather, permitting, drilling rig availability and/or contractual obligations. At December 31, 2017 and 2016, Royale had deferred drilling obligations of $5,891,898 and $7,894,001 respectively.

If Royale is unable to drill the wells, and a suitable replacement well is not found, Royale would retain the non-refundable portion of the contract and return the remaining funds to the participant. Included in cash and cash equivalents are amounts for use in completion of turnkey drilling programs in progress.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil, plant products and gas reserve volumes and the future development costs. Actual results could differ from those estimates.

Deferred Income Taxes

Deferred income taxes reflect the net tax effects, calculated at currently enacted rates, of (a) future deductible/taxable amounts attributable to events that have been recognized on a cumulative basis in the financial statements or income tax returns, and (b) operating loss and tax credit carry forwards. All available evidence, both positive and negative, must be considered to determine whether, based on the weight of that evidence, a valuation allowance for deferred tax assets is needed. The Company uses information about the Company's financial position and its results of operations for the current and preceding years.

The Company must use its judgment in considering the relative impact of negative and positive evidence. The weight given to the potential effect of negative and positive evidence is commensurate with the extent to which it can be objectively verified. The more negative evidence that exists, the more positive evidence is necessary and the more difficult it is to support a conclusion that a valuation allowance is not needed for some portion or all of the deferred tax asset. A cumulative loss in recent years is a significant piece of negative evidence that is difficult to overcome.

Future realization of a tax benefit sometimes will be expected for a portion, but not all, of a deferred tax asset, and the dividing line between the two portions may be unclear. In those circumstances, application of judgment based on a careful assessment of all available evidence is required to determine the portion of a deferred tax asset for which it is more likely than not a tax benefit will not be realized.

Going Concern

At December 31, 2017, the Company has an accumulated deficit of $48,205,690, a working capital deficiency of $7,752,695 and a stockholders' deficit of $6,940,241. As a result, our financial statements include a "going concern qualification" reflecting substantial doubt as to our ability to continue as a going concern. *See Note 1 to our audited financial statements*. We have merged with Matrix to increase efficiency and reduce costs to both companies, thereby allowing a return to positive cash flow. We are exploring commitments to provide additional financing, but there is no guarantee that we will be able to secure additional financing on acceptable terms, or at all, if needed to fully fund our 2018 drilling budget and to support future operations.

Results of Operations for the Twelve Months Ended December 31, 2017, as Compared to the Twelve Months Ended December 31, 2016

For the year ended December 31, 2017, we recorded a net loss of $2,427,169, compared to net loss of $4,144,462 during 2016. Total revenues from operations in 2017 were $1,007,379, a decrease of $206,460, or 17.0% from the total revenues of $1,213,839 in 2016, due to lower lease operating overhead receipts due mainly to the sale of our Victor Ranch field interests in 2016. Total expenses for operations in 2017 were $4,836,429, a decrease of $1,669,287, or 25.7%, from the total expenses of $6,505,716 in 2016, mainly due to the impairment loss in 2016 due to termination of our remaining Alaska leases.

In 2017, revenues from oil and gas production increased by 2.9% to $554,235 from $538,631 in 2016. This increase was due to higher natural gas commodity prices received in 2017. The net sales volume of natural gas for the year ended December 31, 2017, was approximately 190,111 MCF with an average price of $2.89 per MCF, versus 232,539 MCF with an average price of $2.31 per MCF for 2016. This represents a decrease in net sales volume of 42,428 MCF or 18.2%. This decrease in production volume was mainly due to the natural declines in our wells, and the sale of our Victor Ranch field interests which had an effective date of September 1, 2016. Additionally in 2017, our operated wells were temporarily offline in November and December 2017 due to new pipeline equipment requirements by Pacific Gas & Electric. The net sales volume for oil and condensate (natural gas liquids) production was approximately 102 barrels with an average price of $46.07 per barrel for the year ended December 31, 2017, compared to 193 barrels at an average price of $12.11 per barrel, which was lower due to the inclusion of oil byproducts in the barrel count, for the year in 2016. This represents a decrease in net sales volume of 91 barrels, or 47.2%, also due to the natural declines on existing oil and condensate wells. Northern and central California accounted for approximately 91% of the Company's successful natural gas production in 2017.

Oil and natural gas lease operating expenses decreased by $158,604, or 26.7% to $435,637 for the year ended December 31, 2017, from $594,241 for the year in 2016. This decrease was due to the sale of our Victor Ranch field interests in 2016 which reduced overhead, pumping and compression costs during 2017. When measuring lease operating costs on a production or lifting cost basis, in 2017, the $435,637 equates to a $2.28 per MCFE lifting cost versus a $2.54 per MCFE lifting cost in 2016, a 10.2% decrease, due to lower production volumes in 2017.

At December 31, 2017, Royale had a deferred drilling obligation of $5,891,898. During 2017, we disposed of $5,934,604 of obligations relating to 2016, upon completing the drilling of three developmental natural gas wells and participating in the drilling of an additional developmental oil well, while incurring expenses of $4,446,780. This resulted in a gain of $1,487,824. During 2016, we disposed of $4,502,026 of obligations relating to 2015, upon completing the drilling of three wells, two exploratory and one developmental, while incurring expenses of $4,041,816, resulting in a gain of $460,210. Royale expects to dispose of approximately $2.3 million of its deferred drilling obligation in the first six months of 2018 with $2.1 million of its deferred drilling obligation disposed of by the end of 2018.

During the years ended December 31, 2017 and 2016, we recorded gains of $73,325 and $341,751, respectively, on the settlement of accounts payable. During the years in 2017 and 2016, we also recorded write downs of $16,375 and $19,151, respectively, on certain oil and gas well equipment that were either no longer useable or written down to their current market value. During 2016, we recorded a gain of $284,419 on the sale of interests in our Victor Ranch field wells and leases. During 2016, we also recorded a gain of $198,975 on the sale of our Company owned office building located in El Cajon, California. In 2016, we recorded a loss on disposal of assets of $23,781, on fixed assets that were no longer viable.

Impairment losses of $289,775 and $2,071,849 were recorded in 2017 and 2016, respectively. We periodically review our proved properties for impairment on a field-by-field basis and charge impairments of value to the expense. In 2017, the impairments were on various capitalized leases that were no longer viable. In 2016, $2,025,546 of the impairment loss was due to termination of our remaining Alaska leases which were not renewed due to nonpayment of the delay rental payments. Also in 2016, $46,303 of the impairment loss was due to capitalized lease and land costs on a Texas lease that was no longer viable.

Bad debt expense for 2017 and 2016 were $164,145 and $0, respectively. The expenses in 2017 arose from identified uncollectable receivables relating to our oil and natural gas properties either plugged and abandoned or scheduled for plugging and abandonment and our year-end oil and natural gas reserve values. We periodically review our accounts receivable from working interest owners to determine whether collection of any of these charges appears doubtful. By contract, the Company may not collect some charges from its Direct Working Interest owners for certain wells that ceased production or had been sold during the year, to the extent that these charges exceed production revenue.

The aggregate of supervisory fees and other income was $453,144 for the year ended December 31, 2017, a decrease of $222,064 or 32.9% from $675,208 during the year in 2016. This decrease was due to lower operations and drilling overhead and pipeline fees due to lower production volumes during the period in 2017 mainly due to the sale of our Victor Ranch field interests in 2016. Supervisory fees are charged in accordance with the Council for Petroleum Accountants Societies (COPAS) policy for reimbursement of expenses associated with the joint accounting for billing, revenue disbursement, and payment of taxes and royalties. These charges are reevaluated each year and adjusted up or down as deemed appropriate by a published report to the industry by Ernst & Young, LLP, Certified Public Accountants. Supervisory fees decreased $209,540 or 51.5%, to $197,020 in 2017 from $406,560 in 2016.

Depreciation, depletion and amortization expense decreased to $116,017 from $283,874 a decrease of $167,857 or 59.1% for the year ended December 31, 2017, as compared to 2016. The depletion rate is calculated using production as a percentage of reserves. This decrease in depreciation expense was due to a lower depletion rate as reserve volumes were higher at the end of 2017 and a lower asset base due to the sale of our Victor Ranch field interests and our office building in 2016.

General and administrative expenses decreased by $608,872 or 23.3%, to $2,005,630 for the year ended December 31, 2017, from $2,614,502 for the year in 2016. This decrease was primarily due to reductions in outside consulting services in 2017. Legal and accounting expense increased to $1,540,190 for the year, compared to $627,577 for 2016, a $912,613 or 145.4% increase. The increase in 2017 was mainly due to legal and accounting expenses related to the Matrix merger and the legal settlement discussed previously in Item 3.

Marketing expense for the year ended December 31, 2017, decreased $25,862 or 8.8%, to $268,660, compared to $294,522 for the year in 2016. Marketing expense varies from period to period according to the number of marketing events attended by personnel and their associated costs.

During 2017, interest expense increased to $159,268 from $114,159 in 2016, a $45,109 or 39.5% increase. This increase resulted from interest accrued on its convertible promissory notes issued in August 2016. Further details concerning Royale's notes payable can be found in *Capital Resources and Liquidity*, below.

In 2017 and 2016, we did not have an income tax expense due to the use of a percentage depletion carryover valuation allowance created from the current and past operations resulting in an effective tax rate less than the normal federal rate of 34% plus the relevant state rates (mostly California, 8.8%).

Capital Resources and Liquidity

At December 31, 2017, Royale had current assets totaling $4,358,082 and current liabilities totaling $12,110,777, a $7,752,695 working capital deficit. We had cash and cash equivalents at December 31, 2017 of $3,338,693 compared to $4,994,598 at December 31, 2016.

Ordinarily, we fund our operations and cash needs from our available credit and cash flows generated from operations. We believe that consummation of the Merger will enable the combined companies to meet their liquidity demands. However, because the Merger results in different liquidity needs than Royale had before the Merger, there is doubt as to the ability to meet liquidity demands through cash flow or ongoing operations. In that event, the Company will seek alternative capital sources through additional sales of equity or debt securities, or the sale of property.

At December 31, 2017, our other receivables, which consist of receivables from direct working interest investors and industry partners, totaled $764,015, compared to $676,647 at December 31, 2016, a $87,368 or 12.9% increase. This increase was mainly due to receivables from investors for workovers on a non-operated well. Royale's revenue receivable at the end of 2017 was $106,007, a decrease of $197,521 or 65.1%, compared to $303,528 at the end of 2016, due to lower oil and gas production volumes when compared to year end 2016 due to our operated wells being offline in November and December 2017. At December 31, 2017, our accounts payable and accrued expenses totaled $4,638,879, an increase of $2,169,634 or 87.9% over the accounts payable at the end of 2016 of $2,469,245, mainly due to year end drilling activities, merger related trade accounts payable and non-operated workover costs.

In July 2016, we received a cash investment of $1,580,000 from two investors to purchase convertible promissory notes with principal amounts of $1,280,000 and $300,000, with a conversion price of $0.40 per share, with warrants to purchase one share of common stock for every three shares of common stock issuable upon conversion of the notes. The notes originally matured on August 2, 2017, one year from the date of issuance, and carried a 10% interest rate, with a default rate of 25%. Shortly before completion of the Merger, the $300,000 note was converted into 750,000 shares of Royale common stock, and Royale agreed to a cash settlement with the holder of the $1,280,000 note for $1,900,000. *See Item 3, Defaults upon Senior Securities.*

In December of 2013, Royale purchased an office building for $2,000,000, of which $500,000 was paid in cash on the date of purchase, and $1,500,000 was borrowed from AmericanWest Bank, with a note secured by the property being purchased. The note carried an interest rate of 5.75% until paid in full. In February 2016, Royale entered into a purchase and sale agreement for the sale of the office building for $2.5 million. In June 2016, the sale of the building was completed which resulted in a gain of $198,975 and the related principal and interest payments were paid in full.

We have not engaged in hedging activities or use derivative instruments to manage market risks.

The following schedule summarizes our known contractual cash obligations at December 31, 2017, and the effect such obligations are expected to have on our liquidity and cash flow in future periods.

	Total Obligations	2018	2019-2020	2021	Beyond
Office Lease	$ 515,296	$ 119,286	$ 250,606	$ 131,602	$ 13,802

Operating Activities. For the years ended December 31, 2017 and 2016, cash used by operating activities totaled $1,199,439 and $3,271,631, respectively. This $2,072,192 or 63.3% decrease in cash used was mainly due to higher accounts payable and accrued expenses mainly related to both drilling activities at year end 2017 and merger related costs during 2017. During the year in 2016, executive management and directors received 2,335,461 compensatory shares of the Company’s common stock valued at $645,986.

Investing Activities. Net cash used by investing activities totaled $456,466 for the year ended December 31, 2017. Net cash provided by investing activities totaled $3,208,378 for the nine months ended September 30, 2016. This $3,664,844 difference in net cash can be attributed to the sale of our office building and the proceeds received of approximately $936,000, along with $350,000 received from the sale of our interests in the Victor Ranch leases Additionally, our turnkey drilling expenditures were higher in 2017, where we drilled three natural gas wells and participated in the drilling of an additional oil well, while in 2016 we drilled three natural gas wells.

Financing Activities. No net cash was provided or used in financing activities during the year in 2017. Net cash provided by financing activities totaled $1,294,032 in 2016. During the year in 2016, $1,580,000 was provided by the Cash Advances from Pending Transactions, mentioned earlier and $1,446,853 was used for principal payments on the Company’s note payable in the sale of its office building. Also in 2016, we issued 3,027,070 restricted common shares and 789,658 additional warrants and received cash proceeds of $1,160,885 under private placement stock sales. In 2016, cash used from financing activities were added to working capital and used for ordinary operating expenses.

Changes in Reserve Estimates

During 2017, our overall proved developed and undeveloped reserves increased by 4% and our previously estimated proved developed and undeveloped reserve quantities were revised upward by approximately .31 million cubic feet of natural gas. This upward revision reflected higher than previously estimated proved producing and non-producing natural gas reserves at eight California wells and one Utah well. See Supplemental Information about Oil and Gas Producing Activities (Unaudited), page F-23.

During 2016, our overall proved developed and undeveloped reserves decreased by 19% and our previously estimated proved developed and undeveloped reserve quantities were revised upward by approximately .07 million cubic feet of natural gas. This upward revision reflected higher than previously estimated proved producing and non-producing natural gas reserves at eight California wells and one Louisiana well. See Supplemental Information about Oil and Gas Producing Activities (Unaudited), page F-23.

Item 7 **Qualitative and Quantitative Disclosures About Market Risk**

Royale is exposed to market risk from changes in commodity prices and in interest rates. In 2017, we sold a majority of our natural gas at the daily market rate through the Pacific Gas & Electric pipeline. In 2017, our natural gas revenues were approximately $550,000 with an average price of $2.89 per MCF. At current production levels, a 10% per MCF increase or decrease in our average price received could potentially increase or decrease our natural gas revenues by approximately $55,000. We currently do not sell any of our natural gas or oil through hedging contracts.

Item 8 **Financial Statements and Supplementary Data**

See pages F-1, et seq., included herein.

Item 9 **Changes in and Disagreements with Accountants on Accounting and Financial Disclosure**

None

Item 9A **Controls and Procedures**

Disclosure Controls

Disclosure controls are controls and other procedures that are designed to ensure that information required to be disclosed by us in reports that we file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Our disclosure controls and procedures are designed to insure that the information required to be filed is accumulated and communicated to our management in a manner designed to enable them to make timely decisions regarding required disclosure.

Our executive officers, Jonathan Gregory, Chief Executive Officer, Donald H. Hosmer, President of Business Development and Stephen M. Hosmer, President and Chief Financial Officer, evaluated the effectiveness or our disclosure controls and procedures as of the end of the 2017 fiscal year. Based on their evaluation, they concluded that our disclosure controls are effective as of December 31, 2017.

Management Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company, (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Company's assets that could have a material effect on the financial statements. Management assessed our internal control over financial reporting as of December 31, 2016, which was the end of our fiscal year. Management based its assessment on criteria established in the SEC Commission Guidance Regarding Management's Report on Internal Control Over Financial Reporting Under Section 13(a) or 15(d) of the Securities Exchange Act of 1934. The guidance sets forth an approach by which management can conduct a top-down, risk-based evaluation of internal control over financial reporting. Management's assessment included an evaluation of risks to reliable financial reporting, whether controls exist to address those risks and evaluated evidence about the operation of the controls included in the evaluation based on its assessment of risk.

A material weakness is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis. Management identified an internal control deficiency that represents a material weakness in or internal control over financial reporting as of December 31, 2016, in that, certain legal documents, such as debt and equity financing transactions, during the fiscal year were not supported by fully executed agreements.

The control deficiency that gave rise to the material weakness did not result in a material misstatement of our financial statements for the fiscal year ending December 31, 2016.

Because of the material weakness described above, our management was unable to conclude that our internal control over financial reporting was effective as of the end of the fiscal year to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with generally accepted accounting principles. Management is seeking written acknowledgement of the note transactions from the note holders in order to remediate the material weakness described above and will require written acknowledgement from counterparties of all similar future transactions.

Except for the actions described above that were taken to address the material weaknesses, there were no changes in our internal controls during the fiscal year ended December 31, 2017 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting. We reviewed the results of management’s assessment with the Audit Committee of our Board of Directors.

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

Changes in Internal Control over Financial Reporting

No changes in our internal control over financial reporting occurred during the last fiscal quarter of 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Limitations on Effectiveness of Controls

Our management, including our CEO and CFO, does not expect that our disclosure controls or internal controls over financial reporting will prevent all error or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, but not absolute, assurance that the objectives of a control system are met. Any control system contains limitations imposed by resources and relevant cost considerations. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues have been addressed. These inherent limitations include the realities that judgments can be faulty and that breakdowns can occur because of simple error or mistake. In addition, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of a control. Our control system design is also based on assumptions about the likelihood of future events, and we cannot be sure that we have considered all possible future circumstances and events.

PART III

Item 10 **Directors and Executive Officers of the Registrant**

All of our directors serve one year terms from the time of their election to the time their successor is elected and qualified. The following information is furnished with respect to each director and executive officer who served as such during the fiscal year ended December 31, 2017:

Name	Age	First Became Director or Executive Officer	Positions Held
Harry E. Hosmer	87	1986	Chairman of the Board
Donald H. Hosmer	63	1986	President of Business Development and Director
Stephen M. Hosmer	51	1996	President, Chief Financial Officer, Secretary, and Director
Ronald B Verdier (1) (3)	76	2015	Director
Jonathan Gregory	53	2014	Chief Executive Officer and Director
Gary Grinsfelder (1) (2) (3)	68	2007	Director
Ronald Buck (1) (2) (3)	82	2015	Director

(1) Member of the audit committee.
(2) Member of the compensation committee.
(3) Member of the nominations committee.

The board has determined that directors Gary Grinsfelder, Ronald Buck, and Ronald Verdier qualify as independent directors.

The following summarizes the business experience of each director and executive officer for the past six years.

Harry E. Hosmer – Chairman of the Board

Harry E. Hosmer has served as chairman since Royale began in 1986, and from inception in 1986 until June 1995, he also served as president and chief executive officer.

Jonathan Gregory – Chief Executive Officer and Director

Mr. Gregory was appointed Royale's chief executive officer on September 10, 2015. Mr. Gregory has previously served as chief financial officer for private independent exploration and production companies, where he was actively engaged in multiple debt and equity financings, and overseeing acquisition and development activities. Mr. Gregory has over 20 years of oil and gas reserve based lending experience. Mr. Gregory is a member of Houston Energy Finance Group; and ADAM Houston Energy Network. He is also a Co-Founder of Bread of Life, Inc., a non-profit organization committed to empowering homeless Houstonians; and a past director of Small Steps Nurturing Center, a non-profit Christian organization that provides early childhood education for economically at-risk children in the inner-city of Houston, Texas. Mr. Gregory graduated from Lamar University in 1986 with a Bachelors degree in Finance.

Donald H. Hosmer – President of Business Development and Director

Donald H. Hosmer has served as an executive officer and director of Royale since its inception in 1986. In June 1995 he became president and chief executive officer. In October 2008, he became co-president and co-chief executive officer, with primary responsibility for marketing and investor/shareholder relations for the company. Donald H. Hosmer is the son of Harry E. Hosmer and brother of Stephen M. Hosmer.

Stephen M. Hosmer – President, Chief Financial Officer, Secretary, and Director

Stephen M. Hosmer joined Royale as the management information systems manager in May 1988, responsible for developing and maintaining Royale's computer software. Mr. Hosmer developed programs and software systems used by Royale. From 1991 to 1995, he served as president of Royale Operating Company, Royale's operating subsidiary. In 1995, he became chief financial officer of Royale. In 1996, he was elected to the board of directors of Royale. In 2003, he was elected executive vice president. In October 2008, he became co-president and co-chief executive officer with primary responsibility for oil and gas exploration operations. Mr. Hosmer served three years on the board of directors of Exile International, a charitable organization based in Nashville, Tennessee. Mr. Hosmer served seven years on the board of directors of Youth for Christ, a charitable organization in San Diego, California. He currently serves on the board of Venture Expeditions (www.ventureexpeditions.org), a charitable organization based in Minneapolis MN. Stephen M. Hosmer is the son of Harry E. Hosmer and brother of Donald H. Hosmer. Mr. Hosmer holds a Bachelor of Science degree in Business Administration from Oral Roberts University in Tulsa, Oklahoma, as well as earning his MBA degree via the prestigious President/Key Executive program at Pepperdine University in Malibu, California.

Gary Grinsfelder – Director

Mr. Grinsfelder is a geologist and manager with 38 years' experience in oil and gas exploration, exploitation and property evaluation. Currently Mr. Grinsfelder is an independent industry consultant. Previously, Mr. Grinsfelder was Vice President of Exploration at LeFrak Energy and President of TXCO Resources. He has also served in geologic and management roles for Output Exploration, LLC, Araxas Exploration, Inc., Triad Energy Corporation, Spartan Petroleum Corporation, American Petrofina Company of Texas, Union Oil Company of California and Degolyer and MacNaughton. He received a Bachelor of Science degree in 1972 from Southern Methodist University and has performed graduate studies at the University of Puerto Rico Department of Marine Science and University of Houston Department of Geology.

Ronald B Verdier

Mr. Verdier was appointed to the board in 2015 following the resignation of Tony Hall. Mr. Verdier is a retired banker who began his career in banking in 1968. He served as an employee and officer of Mercantile Trust & Savings Bank, Quincy, Illinois, for thirty-three years, ending as Senior Vice President. In 2002, Mr. Verdier retired from Mercantile Trust & Savings Bank and became President of Hannibal National Bank, Hannibal Missouri, where he served until his retirement in 2012. Mr. Verdier is a graduate of the School of Banking at the University of Wisconsin, Madison, and of the School of Banking at the University of Oklahoma. Based on his qualifications, the board of directors has designated Mr. Verdier as an audit committee financial expert.

Ronald L. Buck

Mr. Buck was elected to the board in 2015. Mr. Buck received a Bachelor of Science degree in Marketing and a Minor in Geology and Economics from Northwestern University. After building his business into a large scale distribution company, he sold the company to his two sons in 1992. Since 1992 he has been in finance and managing family assets including oil and gas wells and oil gathering pipeline investments. In this capacity, he also travels extensively to financial meetings and is a member of the National Association of Financial Advisors.

Audit Committee

The board has appointed an audit committee to assist the board of directors in carrying out its responsibility as to the independence and competence of the Company's independent public accountants. All members of the audit committee are independent members of the board of directors. The audit committee operates pursuant to an audit committee charger, which has been adopted by the board of directors to define the committee's responsibilities. A copy of the audit committee charter is posted on our website, www.royl.com The board has determined that Ronald Verdier qualifies as an "audit committee financial expert" as defined in Item 407(d)(5) of the Securities and Exchange Commission.

At the end of 2017, the members of the audit committee were Ronald Verdier, chair, Ronald Buck and Gary Grinsfelder.

Code of Business Conduct and Ethics

We have adopted a code of business conduct and ethics for our directors and executive officers. The code is posted on our website, www.royl.com.

Compliance with Section 16(a) of the Exchange Act

Section 16(a) of the Securities Exchange Act of 1934 and Securities and Exchange Commission regulations require that Royale's directors, certain officers, and greater than 10 percent shareholders file reports of ownership and changes in ownership with the SEC and the NASD and furnish Royale with copies of all such reports they file. Based solely upon a review of the copies of the forms furnished to Royale, or representations from certain reporting persons that no reports were required, Royale believes that no persons failed to file required reports on a timely basis for 2017.

Item 11 Executive Compensation

The following table summarizes the compensation of the chief executive officer, chief financial officer and the one other most highly non-executive employees (the "named executives and employees") of Royale and its subsidiaries during the past year. No stock options, stock awards or other plan based compensation awards were made during 2017.

Name and Principal Position	Year	Salary (4)	Bonus	Option Awards (1)	All Other Compensation (2)	Total
Jonathan Gregory, CEO (3) (4)	2017	$ 242,469	$ -		$ -	$ 242,469
	2016	$ 242,469	$ -		$ -	$ 242,469
	2015	$ 70,823	$ -		$ -	$ 70,823
Donald H. Hosmer	2017	$ 236,331	$ -		$ 19,090	$ 255,421
President	2016	$ 282,533	$ -		$ 18,339	$ 300,872
	2015	$ 177,084	$ -		$ 18,063	$ 195,147
Stephen M. Hosmer (4)	2017	$ 230,192	$ -		$ 18,906	$ 249,098
President, & CFO	2016	$ 207,693	$ -		$ 18,231	$ 225,924
	2015	$ 230,192	$ -		$ 17,968	$ 248,160

(1) October 2014, Donald Hosmer and Stephen Hosmer (together with the other members of the board of directors) were each granted 20,000 options to purchase common stock at an exercise or base price of $5.00 per shares, which vested during 2015. These options were granted for a period of 3 years and will expire on December 31, 2017. At December 29, 2017, Royale's stock price, $0.36, was less than the weighted average exercise price, and as such the outstanding and exercisable stock options had no intrinsic value.

(2) All other compensation consists of matching contributions to the Company's simple IRA plan, except for Donald H. Hosmer and Stephen M. Hosmer, who also received a $12,000 car allowance.

(3) During 2016 and 2015, Jonathan Gregory, Donald and Stephen Hosmer received a portion of their compensation in shares of common stock, valued at the closing market price on the date of grant, instead of cash. In 2016, of the $242,469 paid to Jonathan Gregory, $141,814 was paid in cash and 386,178 shares of common stock were issued, valued at $100,655. Of the $282,533 paid to Donald Hosmer, $190,595 was paid in cash and 609,702 shares of common stock were issued, valued at $91,938. Of the $207,693 paid to Stephen Hosmer, $165,742 was paid in cash and 101,630 shares of common stock were issued, valued at $41,951. In 2015, of the $70,823 paid to Jonathan Gregory, $21,581 was paid in cash and 108,644 shares of common stock were issued, valued at $49,242. Of the $230,192 paid to Stephen Hosmer, $173,945 was paid in cash and 200,564 shares of common stock were issued, valued at $56,247.

(4) Mr. Gregory was appointed CEO (principal executive officer) in 2015.

Stock Options and Equity Compensation; Outstanding Equity Awards at Fiscal Year End

The following table presents the number of unexercised options at the 2017 year end for each named executive officer. No unvested stock awards were outstanding at the end of 2017.

	Options			
Name	Number of securities underlying unexercised options (#) exercisable	Number of securities underlying unexercised options (#) unexercisable	Option exercise price ($)	Option expiration date
Jonathan Gregory	20,000(1)	-	$ 5.00	12/31/2017
Donald H. Hosmer	20,000(1)	-	$ 5.00	12/31/2017
Stephen M. Hosmer	20,000(1)	-	$ 5.00	12/31/2017

(1)
At the October 10, 2014 Board of Directors meeting, directors of Royale were granted 20,000 options each to purchase common stock at an exercise price of $5.00 per share. These options expired on December 31, 2017.

Compensation Committee Report

Our executive compensation committee has reviewed and discussed the following Compensation Discussion and Analysis with management and, based on its discussion and review, has recommended that the Compensation Discussion and Analysis be included in this proxy statement.

Members of the Compensation Committee:

Ronald Buck and Gary Grinsfelder

All members of the compensation committee are independent members of the board of directors.

Compensation Discussion and Analysis

Our executive compensation policy is designed to motivate, reward and retain the key executive talent necessary to achieve our business objectives and contribute to our long-term success. Our compensation policy for our executive officers focuses primarily on determining appropriate salary levels and performance-based cash bonuses.

The elements of executive compensation at Royale consist mainly of cash salary and, if appropriate, a cash bonus at year end. The compensation committee makes recommendations to the board of directors annually on the compensation of the three top executives: Jonathan Gregory, Chief Executive Officer, Donald H. Hosmer, President of Business Development and Stephen M. Hosmer, President and Chief Financial Officer. We do not have employment contracts with either of our executive officers.

Royale also does not provide extensive personal benefits to its executives beyond those benefits, such as health insurance, that are provided to all employees. Donald Hosmer and Stephen Hosmer each receive an annual car allowance.

Policy

The compensation committee's primary responsibility is making recommendations to the board of directors relating to compensation of our officers. The committee also makes recommendations to the board of directors regarding employee benefits, our defined benefit plans, defined contribution plans, and stock based plans.

Determination

To determine executive compensation, the committee, in December each year, meets with our officers to review our compensation programs, discuss the performance of the company, the duties and responsibilities of each of the officers pay levels and business results compared to others similarly situated within the industry. The committee then makes recommendations to the board of directors for any adjustment to the officers' compensation levels. The committee does not employ compensation consultants to make recommendations on executive compensation.

Compensation Elements

Base. Base salaries for our executive officers are established based on the scope of their responsibilities, taking into account competitive market compensation paid by our peers. Base salaries are reviewed annually. The salaries we paid to our most highly paid executive officers for the last three years are set forth in the Summary Compensation Table included under *Executive Compensation*.

Bonus. The compensation committee meets annually to determine the quantity, if any, of the cash bonuses of executive officers. The amount granted is based, subjectively, upon the company's stock price performance, earnings, revenue, reserves and production. The committee does not use quantifiable metrics for these criteria; but rather uses each in balance to assess the strength of the company's performance. The committee believes that formulaic approaches to cash incentives can foster an unhealthy balance between short-term and long-term goals. No bonuses were paid to executive officers in 2017 or 2016.

Compensation of Directors

In 2017, board members or committee member accrued or received fees for attendance at board meetings or committee meetings during the year. In addition to cash payments, common stock was issued in lieu of compensation or reimbursements. Royale also reimbursed directors for the expenses incurred for their services.

The following table describes the compensation paid to our directors who are not also named executives for their services in 2017.

Name	Fees earned or paid in cash or Common Stock ($)	Stock awards ($)	Option awards ($)	All Other Compensation ($)	Total ($)
Harry E. Hosmer	$ 25,000	$ -	$ -	$ -	$ 25,000
Gary Grinsfelder	$ 25,000	$ -	$ -	-	$ 25,000
Ronald Buck	$ 25,000	$ -	$ -	-	$ 25,000
Ronald Verdier	$ 25,000	$ -	$ -	-	$ 25,000

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

Common Stock

On February 27, 2018 (prior to the Merger), 21,850,185 shares of Royale's common stock were outstanding.

The following table contains information regarding the ownership of Royale's common stock as February 27, 2018, by:

i) each person who is known by Royale to own beneficially more than 5% of the outstanding shares of each class of equity securities;

ii) each director and executive officer of Royale, and

iii) all directors and officers of Royale as a group. Except pursuant to applicable community property laws and except as otherwise indicated, each shareholder identified in the table possesses sole voting and investment power with respect to its or his shares. The holdings reported are based on reports filed with the Securities and Exchange Commission and the Company by the officers, directors and 5% shareholders pursuant to Section 16 of the Securities Exchange Act of 1934.

Stockholder (1)	Number	Percent
Harry E. Hosmer, (2) (3)	1,549,319	7.09%
Donald H. Hosmer, (2)	1,475,864	6.75%
Stephen M. Hosmer, (2) (4)	1,358,229	6.22%
Ronald L. Buck (5)	84,688	*
Jonathan Gregory (6),	440,267	2.01%
Gary Grinsfelder, (7)	126,093	*
Ronald Verdier	51,257	*
All officers and directors as a group	5,085,717	22.26%
* Less than 1%		

(1) The mailing address of each listed stockholder is 1870 Cordell Court, Suite 210, El Cajon, California 92020.

(2) Donald H. Hosmer and Stephen M. Hosmer are sons of Harry E. Hosmer, chairman of the board.

(3) Shares are owned by family trust.

(4) Includes 12,000 shares owned by Stephen M. Hosmer's minor children.

(5) Includes 83,688 shares owned by a retirement trust.

(6) Includes 35,000 shares owned by Mr. Gregory's son.

(7) Includes 49,257 shares owned by a retirement trust.

Item 13 Certain Relationships and Related Transactions

In 1989, the board of directors adopted a policy (the "1989 policy") that permits each director and officer of Royale to purchase from Royale, at its cost, up to one percent (1%) fractional interest in any well to be drilled by Royale. When an officer or director elects to make such a purchase, the amount charged per each percentage working interest is equal to Royale's actual pro rata cost of drilling and completion, rather than the higher amount that Royale charges to working interest holders for the purchase of a percentage working interest in a well. Of the current officers and directors, Donald Hosmer, Stephen Hosmer and Harry E. Hosmer at various times have elected under the 1989 policy to purchase interests in certain wells Royale has drilled.

Under the 1989 policy, officers and directors may elect to participate in wells at any time up until drilling of the prospect begins. Participants are required to pay all direct costs and expenses through completion of a well, whether or not the well drilling and completion expenses exceed Royale's cost estimates, instead of paying a set, turnkey price (as do outside investors who purchase undivided working interests from Royale). Thus, they participate on terms similar to other oil and gas industry participants or joint venturers. Participants are invoiced in advance for their share of estimated direct costs of drilling and completion and later actual costs are reconciled, as Royale incurs expenses and participants make further payments as necessary.

Officer and director participants under this program do not pay some expenses paid by outside, retail investors in working interests, such as sales commissions, if any, or marketing expenses. The outside, turnkey drilling agreement investors, on the other hand, are not obligated to pay additional costs if a drilling project experiences cost overruns or unanticipated expenses in the drilling and completion stage. Accordingly, Royale's management believes that its officers and directors who participate in wells under the board of directors' policy do so on terms the same as could be obtained by unaffiliated oil and gas industry participants in arms-length transactions, albeit those terms are different than the turnkey agreement under which outside investors purchase fractional undivided working interests from Royale.

Donald and Stephen Hosmer each have participated individually in 179 wells each under the 1989 policy. The Hosmer Trust, a trust for the benefit of family members of Harry E. Hosmer, has participated in 178 wells.

Investments in wells under the 1989 policy for the three years ended December 31, 2017, 2016, and 2015 are as follows:

	Year	# of fractional interests	Amount
Donald Hosmer	2017	-	$ -
	2016	1	$ 1,556
	2015	2	$ 3,143
Stephen Hosmer	2017	-	$ -
	2016	1	$ 1,556
	2015	4	$ 4,389
Hosmer Trust	2017	-	$ -
	2016	1	$ 1,556
	2015	4	$ 5,633

Prior to July 2016, Royale's chairman of the board and former president, Harry E. Hosmer, rendered management consulting services to Royale. Royale compensated Mr. Hosmer $96,635 and $165,660 for his consulting services in 2016 and 2015, respectively, and paid his medical insurance costs. Mr. Hosmer's still serves on the board of directors, for which he receives reimbursement of expenses to attend meetings.

Item 14 Principal Accountant Fees and Services

SingerLewak LLP served as the independent auditors to audit the Company's financial statements for the fiscal year ended December 31, 2017 and 2016. This is the fourth annual audit performed by SingerLewak LLP. The aggregate fees billed by SingerLewak LLP for the years ended December 31, 2017 and 2016 are as follows, respectively:

	2017	2016
Audit fees (1)	$ 184,352	$ 139,413
Tax fees (2)	$ -	$ -
All other fees (3)	$ 113,387	$ 18,638
Total	$ 297,739	$ 158,051

(1) Audit fees are fees for professional services rendered for the audit of Royale Energy's annual financial statements, reviews of financial statements included in the company's Forms 10-Q, and reviews of documents filed with the U.S. Securities and Exchange Commission.

(2) Tax fees consist of tax planning, consulting and tax return reviews.

(3) Other fees consist of work on registration statements under the Securities Act of 1933.

The audit committee of Royale Energy has adopted policies for the pre-approval of all audit and non-audit services provided by the company's independent auditor. The policy requires pre-approval by the audit committee of specifically defined audit and non-audit services. Unless the specific service has been previously pre-approved with respect to that year, the audit committee must approve the permitted service before the independent auditor is engaged to perform it.

No representatives of SingerLewak LLP are expected to be present at the annual meeting. Although the audit committee has the sole responsibility to appoint the auditors as required under the Securities Exchange Act of 1934, the committee welcomes any comments from shareholders on auditor selection or performance. Comments may be sent to the audit committee chair, Ronald Verdier, care of Royale Energy's executive office, 1870 Cordell Court, Suite 210, El Cajon, California 92020.

PART IV

Item 15 Exhibits and Financial Statement Schedules

The agreements included as exhibits to this report are included to provide information about their terms and not to provide any other factual or disclosure information about Royale or the other parties to the agreements. The agreements contain representations and warranties by each of the parties to the applicable agreement that were made solely for the benefit of the other agreement parties and:

- should not be treated as categorical statements of fact, but rather as a way of allocating the risk among the parties if those statements prove to be inaccurate;

- have been qualified by disclosures that were made to the other party in connection with the negotiation of the applicable agreement, which disclosures are not necessarily reflected in the agreement;

- may apply standards of materiality in a way that is different from the way investors may view materiality; and

- were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

1. Financial Statements. See Index to Financial Statements, page F-1

2. Schedules. Supplemental Information About Oil and Gas Producing Activities (Unaudited) begins on page F-23.

3. Exhibits. Certain of the exhibits listed in the following index are incorporated by reference.

2.1	Amended and Restated Agreement and Plan of Merger among Royale Energy, Inc., Royale Energy Holdings, Inc. Royale Merger Sub, Inc., Matrix Merger Sub, Inc., and Matrix Oil Management Corporation, filed as Exhibit 2.1, Annex A to the Form S-4/A of Royale Energy Holdings, Inc., filed July 21, 2017
2.2	Amendment No. 7 to the Amended and Restated Agreement and Plan of Merger among Royale Energy, Inc., the Company, Royale Merger Sub, Inc., Matrix Merger Sub, Inc., and Matrix Oil Management Corporation, filed as Exhibit 2.2 to the Form 8-A of Royale Energy Holdings, Inc. (Commission File No. 000-55912), filed March 8, 2018
2.3	Joint Waiver of Closing Conditions between Matrix Oil Management Corporation, on behalf of itself and as general partner of Matrix Investments, L.P., Matrix Permian Investments, LP, , Matrix Las Cienegas Limited Partnership, Matrix Oil Corporation, and all of the holders of preferred limited partnership interests of Matrix Investments (February 28, 2018), filed as Exhibit 2.6 to the Form 8-A of Royale Energy Holdings, Inc. (Commission File No. 000-55912), filed March 8, 2018
3.1	Restated Articles of Incorporation of Royale Energy, Inc., incorporated by reference to Exhibit 3.1 of Royale Energy's Form 10-Q filed August 14, 2009.
3.2	Amended and Restated Bylaws of Royale Energy, Inc., incorporated by reference to Exhibit 3.3 of Royale Energy's Form 10-K filed March 27, 2009.
3.3	Amendment to the Certificate of Incorporation of Royale Energy, Inc., a California corporation (March 7, 2018), filed as Exhibit 3.2 to the Company's Current Report on Form 8-K dated March 7, 2018, filed March 12, 2018
10.1	Consent To Merger, Joinder, Waiver And Fourth Amendment To Term Loan Agreement between Matrix Oil Corporation, Matrix Pipeline LP, Matrix Oil Management Corporation, Matrix Las Cienegas Limited Partnership, Matrix Investments, L.P., Matrix Permian Investments, LP, Matrix Royalty, LP, Royale Energy Holdings, Inc., Royale Energy, Inc., Arena Limited SPV, LLC, Arena Limited SPV, LLC, , and Cargill Incorporated (February 28, 2018), filed as Exhibit 10.6 to the Company's Current Report on Form 8-K dated March 7, 2018, filed March 12, 2018
10.2	Pledge Agreement by Royale Energy, Inc., in favor of Arena Limited SPV, LLC (February 28, 2018)), filed as Exhibit 10.7 to the Company's Current Report on Form 8-K dated March 7, 2018, filed March 12, 2018
21.1	Subsidiaries, filed herewith.
23.1	Consent of SingerLewak L.L.P., filed herewith.
31.1	Rule 13a-14(a), 115d-14(a) Certification, filed herewith.
31.2	Rule 13a-14(a), 115d-14(a) Certification, filed herewith.
31.3	Rule 13a-14(a), 115d-14(a) Certification, filed herewith.
32.1	Section 1350 Certification, filed herewith.
32.2	Section 1350 Certification, filed herewith.
32.3	Section 1350 Certification, filed herewith.
99.1	Report of Netherland Sewell & Associates, Inc., filed herewith.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

* Pursuant to Rule 406T of Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability.

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.

Royale Energy Funds, Inc.

Date: March 23, 2018	*/s/ Jonathan Gregory* Jonathan Gregory Chief Executive Officer

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

Date: March 23, 2018	*/s/ Harry E. Hosmer* Harry E. Hosmer Chairman of the Board of Directors
Date: March 23, 2018	*/s/ Donald H. Hosmer* Donald H. Hosmer Director, and President of Business Development
Date: March 23, 2018	*/s/ Stephen M. Hosmer* Stephen M. Hosmer Director, President, Chief Financial Officer and Secretary
Date: March 23, 2018	*/s/ Ronald Buck* Ronald Buck Director
Date: March 23, 2018	*/s/ Ronald Verdier* Ronald Verdier Director
Date: March 23, 2018	*/s/ Gary Grinsfelder* Gary Grinsfelder Director
Date: March 23, 2018	*/s/ Jonathan Gregory* Jonathan Gregory Director, Chief Executive Officer

ROYALE ENERGY FUNDS, INC.
(Formerly known as Royale Energy, Inc.)
INDEX TO FINANCIAL STATEMENTS
AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Royale Energy Funds, Inc.

Opinion on the Financial Statements

We have audited the accompanying balance sheets of Royale Energy Funds, Inc. (the "Company") as of December 31, 2016 and 2017, the related statements of comprehensive loss, stockholders' deficit, and cash flows for the years then ended, and the related notes to the financial statements (collectively, the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2016 and 2017, 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.

Going Concern

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 1 to the financial statements, the Company has suffered recurring losses from operations, its total liabilities exceed its total assets, and it has an accumulated stockholders' deficit. This raises substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters also are described in Note 1. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Board of Directors and Stockholders
Royale Energy Funds, Inc.
Page Two

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

SingerLewak LLP
We have served as the Company's auditor since 2014.

Los Angeles, California
March 23, 2018

ROYALE ENERGY FUNDS, INC.
BALANCE SHEETS
DECEMBER 31, 2017 AND 2016

	2017	2016
ASSETS		
Current Assets:		
Cash	$ 3,338,693	$ 4,994,598
Other Receivables, net	764,015	676,647
Revenue Receivables	106,007	303,528
Prepaid Expenses	149,367	63,308
Total Current Assets	4,358,082	6,038,081
Other Assets	511,120	610,779
Oil And Gas Properties (Successful Efforts Basis), Real Property and Equipment and Fixtures, net	1,302,242	1,733,424
Total Assets	$ 6,171,444	$ 8,382,284

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

ROYALE ENERGY FUNDS, INC.
BALANCE SHEETS
DECEMBER 31, 2017 AND 2016

	2017	2016
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current Liabilities:		
Accounts Payable and Accrued Expenses	$ 4,638,879	$ 2,469,245
Cash Advances on Pending Transactions	1,580,000	1,580,000
Current Portion of Long-Term Debt	-	-
Deferred Drilling Obligations	5,891,898	7,894,001
Total Current Liabilities	12,110,777	11,943,246
Noncurrent Liabilities:		
Asset Retirement Obligation	1,000,908	952,110
Note Payable, less current portion	-	-
Total Noncurrent Liabilities	1,000,908	952,110
Total Liabilities	13,111,685	12,895,356
Stockholders' Deficit:		
Common Stock, No Par Value, 30,000,000 Shares Authorized; 21,850,185 and 21,836,033 Shares Issued and Outstanding, at December 31, 2017 and 2016, respectively	41,265,449	41,265,449
Accumulated Deficit	(48,205,690)	(45,778,521)
Total Stockholders' Deficit	(6,940,241)	(4,513,072)
Total Liabilities and Stockholders' Deficit	$ 6,171,444	$ 8,382,284

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

ROYALE ENERGY FUNDS, INC.
STATEMENTS OF COMPREHENSIVE LOSS
FOR THE YEARS ENDED DECEMBER 31, 2017, AND 2016

	2017	2016
Revenues:		
Sale of Oil and Gas	$ 554,235	$ 538,631
Supervisory Fees and Other	453,144	675,208
Total Revenues	1,007,379	1,213,839
Costs and Expenses:		
Lease Operating	435,637	594,241
Lease Impairment	289,775	2,071,849
Well Equipment Write Down	16,375	19,151
Bad Debt Expense	164,145	-
General and Administrative	2,005,630	2,614,502
Legal and Accounting	1,540,190	627,577
Marketing	268,660	294,522
Depreciation, Depletion and Amortization	116,017	283,874
Total Costs and Expenses	4,836,429	6,505,716
Gain on Turnkey Drilling Programs	1,487,824	460,210
Loss from Operations	(2,341,226)	(4,831,667)
Other Income (Expense):		
Interest Expense	(159,268)	(114,159)
Gain on Sale of Assets	-	483,394
Gain on Settlement of Accounts Payable	73,325	341,751
Loss on Disposal of Assets	-	(23,781)
Loss Before Income Tax Expense	(2,427,169)	(4,144,462)
Provision for Income Taxes	-	-
Net Loss	(2,427,169)	(4,144,462)
Basic Loss Per Share	(0.11)	(0.22)
Diluted Loss Per Share	(0.11)	(0.22)
Other Comprehensive Income (Loss)		
Unrealized Loss on Equity Securities	-	-
Less: Reclassification Adjustment for Losses Included in Net Income	-	-
Other Comprehensive Gain (Loss) before tax	-	-
Other Comprehensive Gain (Loss), net of tax	-	-
Comprehensive Loss	(2,427,169)	(4,144,462)

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

ROYALE ENERGY FUNDS, INC.
STATEMENTS OF STOCKHOLDERS' DEFICIT
FOR THE YEARS ENDED DECEMBER 31, 2017 and 2016

	Common Stock		Preferred Stock Series AA				
	Number of Shares Issued and Outstanding	Amount	Number of Shares Issued and Outstanding	Amount	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total
Balance, December 31, 2015	16,396,579	$ 39,272,429	46,662	$ 136,149	$ (41,634,959)	$ -	$ (2,225,481)
Common Stock Private Placement Sale	3,027,070	$ 1,160,885					1,160,885
Issuance of Common Stock in Settlement of AP	76,923	50,000					50,000
Common Stock RDO Private Placement Sale							
Common Stock Issued to Executives in lieu of Compensation	2,335,461	645,986					645,986
Preferred Series AA Converted to Common Stock	-	136,149	(46,662)	(136,149)			-
Net Loss					(4,144,462)		(4,144,462)
Balance, December 31, 2016	21,836,033	$ 41,265,449	-	$ -	$ (45,778,521)	$ -	$ (4,513,072)
Common Stock Private Placement Sale	-	-					-
Common Stock Issued to Executives in lieu of Compensation	52,613	25,000					25,000
Issuance of Common Stock in Settlement of AP - Adjustment	(38,461)	(25,000)					(25,000)
Preferred Series AA Converted to Common Stock	-	-					-
Net Loss					(2,427,169)		(2,427,169)
Balance, December 31, 2017	21,850,185	$ 41,265,449	-	$ -	$ (48,205,690)	$ -	$ (6,940,241)

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

ROYALE ENERGY FUNDS, INC.
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2017 and 2016

	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net (Loss)	$ (2,427,169)	$ (4,144,462)
Adjustments to Reconcile Net Loss to Net Cash Used by Operating Activities:		
Depreciation, Depletion, and Amortization	116,017	283,874
Lease Impairment	289,775	2,071,849
Gain on Sale of Assets	-	(483,394)
Gain on Turnkey Drilling Programs	(1,487,824)	(460,210)
Gain on Settlement of Accounts Payable	(73,325)	(341,751)
Loss on Disposal of Assets	-	23,781
Bad Debt Expense	164,145	-
Stock-Based Compensation	-	645,986
Realized Loss on Equity Securities	-	-
Well Equipment and Other Assets Write Down	16,375	19,151
(Increase) Decrease in:		
Other & Revenue Receivables	(53,992)	(451,047)
Prepaid Expenses and Other Assets	13,600	151,642
Increase (Decrease) in:		
Accounts Payable and Accrued Expenses	2,242,959	(587,050)
Net Cash Used by Operating Activities	(1,199,439)	(3,271,631)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Expenditures for Oil And Gas Properties	(4,388,967)	(2,058,357)
Proceeds from Turnkey Drilling Programs	3,932,501	3,980,499
Proceeds from Sale of Assets	-	1,286,236
Net Cash Provided by (Used In) Investing Activities	(456,466)	3,208,378
CASH FLOWS FROM FINANCING ACTIVITIES:		
Cash Advances From Investors	-	1,580,000
Principal Payments on Long-Term Debt	-	(1,446,853)
Proceeds from Issuance of Common Stock	-	1,160,885
Net Cash Provided by Financing Activities	-	1,294,032
Net Increase (Decrease) in Cash	(1,655,905)	1,230,779
Cash at Beginning of Year	4,994,598	3,763,819
Cash at End of Year	$ 3,338,693	$ 4,994,598
Cash Paid for Interest	$ 1,268	48,325
Cash Paid for Taxes	$ 1,539	2,100
Supplemental Schedule of Non-Cash Investing and Financing Transactions:		
Conversion of Series AA Stock to Common Stock	$ -	$ 136,149
Asset Retirement Obligation Addition	$ 65,461	$ -
Issuance of Common Stock for Accrued Compensation Expense	$ 25,000	-
Warrants Issued with Common Stock	$ -	$ 156,205

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

ROYALE ENERGY FUNDS, INC.
NOTES TO FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This summary of significant accounting policies of Royale Energy Funds, Inc. (formerly known as Royale Energy, Inc., and in these notes sometimes called "Royale Energy," "Royale," or the "Company") is presented to assist in understanding Royale Energy's financial statements. The financial statements and notes are representations of Royale Energy's management, which is responsible for their integrity and objectivity. These accounting policies conform to accounting principles generally accepted in the United States of America and have been consistently applied in the preparation of the financial statements.

Description of Business

Royale Energy is an independent oil and gas producer which also has operations in the area of turnkey drilling. Royale Energy owns wells and leases in major geological basins located primarily in California, Texas, Oklahoma and Utah. Royale Energy offers fractional working interests and seeks to minimize the risks of oil and gas drilling by selling multiple well drilling projects which do not include the use of debt financing.

Use of Estimates

The accompanying financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America and requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. As reflected in the accompanying financial statements, the Company has negative working capital, losses from operations and negative cash flows from operations.

Material estimates that are particularly susceptible to significant change relate to the estimate of Company oil and gas reserves prepared by an independent engineering consultant. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proven reserves. Estimated reserves are used in the calculation of depletion, depreciation and amortization, unevaluated property costs, impairment of oil and natural gas properties, estimated future net cash flows, taxes, and contingencies.

Liquidity and going concern

The primary sources of liquidity have historically been issuances of common stock and operations. We believe that the completion of the contemplated merger with will enable us to return to positive cash flow. There is some doubt about the company's ability to meet liquidity demands, and we anticipate that our primary sources of liquidity will be from the issuance of debt and/or equity, and the sale of oil and natural gas property participation interest.

The Company's consolidated financial statements reflect an accumulated deficit of $48,205,690, a working capital deficiency of $7,752,695 and a stockholders' deficit of $6,940,241. These factors raise substantial doubt about our ability to continue as a going concern. The accompanying consolidated financial statements do not include any adjustments that might be necessary if the Company is unable to continue as a going concern.

Management's plans to alleviate the going concern include the proposed merger with Matrix and additional financing through issuances of common stock and the reduction of overhead costs. There is no assurance that additional financing will be available when needed or that management will be able to obtain financing on terms acceptable to the Company and whether the Company will become profitable and generate positive operating cash flow. If the Company is unable to raise sufficient additional funds, it will have to develop and implement a plan to further extend payables, attempt to extend note repayments, and reduce overhead until sufficient additional capital is raised to support further operations. There can be no assurance that such a plan will be successful.

Revenue Recognition

Royale's primary business is oil and gas production. Natural gas flows from the wells into gathering line systems, which are equipped occasionally with compressor systems, which in turn flow into metered transportation and customer pipelines. Monthly, price data and daily production are used to invoice customers for amounts due to Royale Energy and other working interest owners. Royale Energy operates virtually all of its own wells and receives industry standard operator fees.

Royale Energy generally sells crude oil and natural gas under short-term agreements at prevailing market prices. Revenues are recognized when the products are delivered, which occurs when the customer has taken title and has assumed the risks and rewards of ownership, prices are fixed or determinable and collectability is reasonably assured.

Revenues from the production of oil and natural gas properties in which the Royale Energy has an interest with other producers are recognized on the basis of Royale Energy's net working interest. Differences between actual production and net working interest volumes are not significant.

Royale Energy's financial statements include its *pro rata* ownership of wells. Royale Energy usually sells a portion of the working interest in each well it drills or participates in to third party investors and retains a portion of the prospect for its own account. Royale Energy generally retains about a 50% working interest. All results, successful or not, are included at its pro rata ownership amounts: revenue, expenses, assets, and liabilities as defined in FASB ASC 932-323-25 and 932-360.

Oil and Gas Property and Equipment

Depreciation, depletion and amortization, based on cost less estimated salvage value of the asset, are primarily determined under either the unit-of-production method or the straight-line method, which is based on estimated asset service life taking obsolescence into consideration. Maintenance and repairs, including planned major maintenance, are expensed as incurred. Major renewals and improvements are capitalized and the assets replaced are retired.

The project construction phase commences with the development of the detailed engineering design and ends when the constructed assets are ready for their intended use. Interest costs, to the extent they are incurred to finance expenditures during the construction phase, are included in property, plant and equipment and are depreciated over the service life of the related assets.

Royale Energy uses the "successful efforts" method to account for its exploration and production activities. Under this method, Royale Energy accumulates its proportionate share of costs on a well-by-well basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred, and capitalizes expenditures for productive wells. Royale Energy amortizes the costs of productive wells under the unit-of-production method.

Royale Energy carries, as an asset, exploratory well costs when the well has found a sufficient quantity of reserves to justify its completion as a producing well and where Royale Energy is making sufficient progress assessing the reserves and the economic and operating viability of the project. Exploratory well costs not meeting these criteria are charged to expense. Other exploratory expenditures, including geophysical costs and annual lease rentals, are expensed as incurred.

Acquisition costs of proved properties are amortized using a unit-of-production method, computed on the basis of total proved oil and gas reserves.

Capitalized exploratory drilling and development costs associated with productive depletable extractive properties are amortized using unit-of-production rates based on the amount of proved developed reserves of oil and gas that are estimated to be recoverable from existing facilities using current operating methods. Under the unit-of-production method, oil and gas volumes are considered produced once they have been measured through meters at custody transfer or sales transaction points at the outlet valve on the lease or field storage tank.

Production costs are expensed as incurred. Production involves lifting the oil and gas to the surface and gathering, treating, field processing and field storage of the oil and gas. The production function normally terminates at the outlet valve on the lease or field production storage tank. Production costs are those incurred to operate and maintain Royale Energy's wells and related equipment and facilities. They become part of the cost of oil and gas produced. These costs, sometimes referred to as lifting costs, include such items as labor costs to operate the wells and related equipment; repair and maintenance costs on the wells and equipment; materials, supplies and energy costs required to operate the wells and related equipment; and administrative expenses related to the production activity.

Proved oil and gas properties held and used by Royale Energy are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable.

Royale Energy estimates the future undiscounted cash flows of the affected properties to judge the recoverability of carrying amounts. Cash flows used in impairment evaluations are developed using annually updated evaluation assumptions for crude oil commodity prices. Annual volumes are based on field production profiles, which are also updated annually. Prices for natural gas and other products are based on assumptions developed annually for evaluation purposes.

Impairment analyses are generally based on proved reserves. An asset group would be impaired if the undiscounted cash flows were less than its carrying value. Impairments are measured by the amount the carrying value exceeds fair value. During 2017 and 2016, impairment losses of $289,775 and $2,071,849, respectively, were recorded on various capitalized lease and land costs that were no longer viable.

Significant unproved properties are assessed for impairment individually, and valuation allowances against the capitalized costs are recorded based on the estimated economic chance of success and the length of time that Royale Energy expects to hold the properties. The valuation allowances are reviewed at least annually.

Upon the sale or retirement of a complete field of a proved property, Royale Energy eliminates the cost from its books, and the resultant gain or loss is recorded to Royale Energy's Statement of Operations. Upon the sale of an entire interest in an unproved property where the property has been assessed for impairment individually, a gain or loss is recognized in Royale Energy's Statement of Operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a recovery of the cost in the interest retained with any excess funds recognized as a gain. Should Royale Energy's turnkey drilling agreements include unproved property, total drilling costs incurred to satisfy its obligations are recovered by the total funds received under the agreements. Any excess funds are recorded as a Gain on Turnkey Drilling Programs, and any costs not recovered are capitalized and accounted for under the "successful efforts" method.

Royale Energy sponsors turnkey drilling agreement arrangements in unproved properties as a pooling of assets in a joint undertaking, whereby proceeds from participants are reported as Deferred Drilling Obligations, and then reduced as costs to complete its obligations are incurred with any excess booked against its property account to reduce any basis in its own interest. Gains on Turnkey Drilling Programs represent funds received from turnkey drilling participants in excess of all costs Royale incurs during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for its own account; and are recognized only upon making this determination after Royale's obligations have been fulfilled.

The contracts require the participants pay Royale Energy the full contract price upon execution of the agreement. Royale Energy completes the drilling activities typically between 10 and 30 days after drilling begins. The participant retains an undivided or proportional beneficial interest in the property, and is also responsible for its proportionate share of operating costs. Royale Energy retains legal title to the lease. The participants purchase a working interest directly in the well bore.

In these working interest arrangements, the participants are responsible for sharing in the risk of development, but also sharing in a proportional interest in rights to revenues and proportional liability for the cost of operations after drilling is completed and the interest is conveyed to the participant.

A certain portion of the turnkey drilling participant's funds received are non-refundable. The company holds all funds invested as Deferred Drilling Obligations until drilling is complete. Occasionally, drilling is delayed for various reasons such as weather, permitting, drilling rig availability and/or contractual obligations. At December 31, 2017 and 2016, Royale Energy had Deferred Drilling Obligations of $5,891,898 and $7,894,001, respectively.

If Royale Energy is unable to drill the wells, and a suitable replacement well is not found, Royale would retain the non-refundable portion of the contact and return the remaining funds to the participant. Included in cash and cash equivalents are amounts for use in completion of turnkey drilling programs in progress.

Losses on properties sold are recognized when incurred or when the properties are held for sale and the fair value of the properties is less than the carrying value.

Other Receivables

Our other receivables consists of receivables from direct working interest investors and industry partners. We provide for uncollectible accounts receivable using the allowance method of accounting for bad debts. Under this method of accounting, a provision for uncollectible accounts is charged directly to bad debt expense when it becomes probable the receivable will not be collected. The allowance account is increased or decreased based on past collection history and management's evaluation of accounts receivable. All amounts considered uncollectible are charged against the allowance account and recoveries of previously charged off accounts are added to the allowance. At December 31, 2017 and 2016, the Company established an allowance for uncollectable accounts of $1,975,660 and $2,270,773, respectively, for receivables from direct working interest investors whose expenses on non-producing wells were unlikely to be collected from revenue.

Revenue Receivables

Our revenue receivables consists of receivables related to the sale of our natural gas and oil. Once a production month is completed we receive payment approximately 15 to 30 days later.

Equipment and Fixtures

Equipment and fixtures are stated at cost and depreciated over the estimated useful lives of the assets, which range from three to seven years, using the straight-line method. Repairs and maintenance are charged to expense as incurred. When assets are sold or retired, the cost and related accumulated depreciation are removed from the accounts and any resulting gain or loss is included in income. Maintenance and repairs, which neither materially add to the value of the property nor appreciably prolong its life, are charged to expense as incurred. Gains or losses on dispositions of property and equipment, other than oil and gas, are reflected in operations.

Income (Loss) Per Share

Basic and diluted losses per share are calculated as follows:

	For the Year Ended December 31, 2017		
	Loss (Numerator)	**Shares (Denominator)**	**Per-Share Amount**
Basic Loss Per Share:			
Net loss available to common stock	$ (2,427,169)	21,836,975	$ (0.11)
Loss Per Share:			
Effect of dilutive securities and stock options		-	$ -
Net loss available to common stock	$ (2,427,169)	21,836,975	$ (0.11)

	For the Year Ended December 31, 2016		
	Loss (Numerator)	**Shares (Denominator)**	**Per-Share Amount**
Basic Loss Per Share:			
Net income available to common stock	$ (4,144,462)	19,185,896	$ (0.22)
Loss Per Share:			
Effect of dilutive securities and stock options		-	$ -
Net loss available to common stock	$ (4,144,462)	19,185,896	$ (0.22)

Stock Based Compensation

Royale Energy has a stock-based employee compensation plan, which is more fully described in Note 11. Effective January 1, 2006, the Company adopted the Compensation – Stock Compensation Topic of the FASB Accounting Standards Codification, which addresses the accounting for stock-based payment transactions in which an enterprise receives employee services in exchange for (a) equity instruments of the enterprise or (b) liabilities that are based on the fair value of the enterprise's equity instruments or that may be settled by the issuance of such equity instruments. The Company uses the Black-Scholes option-pricing model to determine the fair value of stock-based awards.

Income Taxes

Royale utilizes the asset and liability approach to measure deferred tax assets and liabilities based on temporary differences existing at each balance sheet date using currently enacted tax rates in accordance with the Income Taxes Topic of the FASB Accounting Standards Codification. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. Under the Topic, deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

The provision for income taxes is based on pretax financial accounting income. Deferred tax assets and liabilities are recognized for the expected tax consequences of temporary differences between the tax basis of assets and liabilities and their reported net amounts.

Fair Value Measurements

According to Fair Value Measurements and Disclosures Topic of the FASB Accounting Standards Codification, assets and liabilities that are measured at fair value on a recurring and nonrecurring basis in period subsequent to initial recognition, the reporting entity shall disclose information that enable users of its financial statements to assess the inputs used to develop those measurements and for recurring fair value measurements using significant unobservable inputs, the effect of the measurements on earnings for the period.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. In determining fair value, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible as well as considers counterparty credit risk in its assessment of fair value. Carrying amounts of the Company's financial instruments, including cash equivalents, accounts receivable, accounts payable and accrued liabilities, approximate their fair values as of the balance sheet dates because of their generally short maturities.

The fair value hierarchy distinguishes between (1) market participant assumptions developed based on market data obtained from independent sources (observable inputs) and (2) an entity's own assumptions about market participant assumptions developed based on the best information available in the circumstances (unobservable inputs). The fair value hierarchy consists of three broad levels, which gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). The three levels of the fair value hierarchy are described below:

Level 1: Quoted prices (unadjusted) in active markets that are accessible at the measurement date for assets or liabilities.

> Level 2: Directly or indirectly observable inputs as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.
>
> Level 3: Unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions

At December 31, 2017 and 2016, Royale Energy does not have any financial assets measured and recognized at fair value on a recurring basis. The Company estimates asset retirement obligations pursuant to the provisions of FASB ASC Topic 410, "*Asset Retirement and Environmental Obligations*" ("FASB ASC 410"). The initial measurement of asset retirement obligations at fair value is calculated using discounted cash flow techniques and based on internal estimates of future retirement costs associated with oil and gas properties. Given the unobservable nature of the inputs, including plugging costs and reserve lives, the initial measurement of the asset retirement obligation liability is deemed to use Level 3 inputs. See Note 3 for further discussion of the Company's asset retirement obligations.

Accounts Payable and Accrued Expenses

At December 31, 2017, the components of accounts payable and accrued expenses consisted of $2,392,755 in trade accounts payable due to various vendors, $688,002 in payables and accruals related to direct working interest investors revenues and operating costs, $483,734 in accrued expenses related to current drilling efforts, $438,667 in legal settlement payables related to Cash Advances on Pending Transactions, $266,110 for accrued liabilities for amounts set aside mainly for the plugging and abandonment of certain wells, $93,619 for employee related taxes and accruals, $223,833 related to interest payable on cash advances on pending transactions, $35,036 in deferred rent and $17,123 in federal and state income taxes payable. At December 31, 2016, the components of accounts payable and accrued expenses consisted of $1,205,740 in trade accounts payable due to various vendors, $699,068 in payables and accruals related to direct working interest investors revenues and operating costs, $98,172 in accrued expenses related to current drilling efforts, $266,110 for accrued liabilities for amounts set aside mainly for the plugging and abandonment of certain wells, $103,212 for employee related taxes and accruals, $65,833 related to interest payable on cash advances on pending transactions, $12,446 in deferred rent and $18,662 in federal and state income taxes payable.

Cash Advances on Pending Transactions

In July 2016, we received a cash investment of $1,580,000 from two investors to purchase convertible promissory notes of $1,280,000 and $300,000, with a conversion price of $0.40 per share, with warrants to purchase one share of common stock for every three shares of common stock issuable upon conversion of the notes. The funds from these transactions were used to continue drilling activities, fund expenses incurred in connection with the completion of Royale Energy's merger with Matrix Oil Corporation and for general corporate purposes. The notes originally matured on August 2, 2017, one year from the date of issuance, and carried a 10% interest rate, with a default rate of 25%. Shortly before completion of the Merger, the $300,000 note was converted into 750,000 shares of Royale common stock, and Royale agreed to a cash settlement with the holder of the $1,280,000 note for $1,900,000.

Recently Issued Accounting Pronouncements

The Company has reviewed the updates issued by the Financial Accounting Standards Board (FASB) during the year ended December 31, 2017.

ASU 2017-09: Compensation - Stock Compensation (Topic 718) – Scope of Modification Accounting - In May 2017, the FASB issued ASU 2017-09, which provides guidance about which changes to the terms or conditions of a share-based payment awarded require an entity to apply modification accounting. ASU 2017-09 is effective for interim and annual reporting periods beginning after December 15, 2017, with early adoption permitted. The amendments in ASU 2017-09 are to be applied prospectively to an award modified on or after the adoption date, consequently the impact will be dependent on the modification of any share-based payment awards and the nature of such modifications. The Company is currently evaluating the impact of the adoption of ASU 2017-09 on the Company's financial statements.

ASU 2017-01: Business Combinations (Topic 805) – Clarifying the Definition of a Business - In January 2017, FASB issued ASU 2017-01. The objective of ASU 2017-01 is to clarify the definition of a business by adding guidance on how entities should evaluate whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. The definition of a business affects many areas of accounting including acquisitions, disposals, goodwill, and consolidation. ASU 2017-01 will be effective for public business entities for fiscal years beginning after December 15, 2017, including interim periods in the year of adoption. Early adoption is permitted for any interim or annual period. The Company is in the process of determining the impact that the implementation of ASU 2017-01 will have on the Company's financial statements.

ASU 2016-09: Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting - In March 2016, FASB issued ASU 2016-09 which amends several aspects of the accounting for share-based payment transactions including the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those fiscal years. Early adoption is permitted. If early adopted, an entity must adopt all of the amendments in the same period. The adoption of this guidance has no impact on our results of operations or cash flows.

ASU 2015-17: Income Taxes (Topic740) Balance Sheet Classification of Deferred Taxes – In November 2015, FASB issued ASU 2015-17 which eliminates the requirement to present deferred tax assets and liabilities as current and noncurrent amounts in a classified balance sheet. The new standard requires deferred tax assets and liabilities to be classified as noncurrent. The amendments in this update are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier application is permitted for all entities as of the beginning of an interim or annual reporting period and may be applied either prospectively or retrospectively to all periods presented. In 2016, the Company adopted Accounting Standards Update (ASU) 2015-17 and has classified all of its deferred tax assets and liabilities as noncurrent on its balance sheet. The adoption of this guidance has no impact on our results of operations or cash flows.

ASU 2016-01: Financial Instruments – Overall – Recognition and Measurement of Financial Assets and Financial Liabilities (Subtopic 825-10) In January 2016, FASB issued ASU 2016-01 which requires an entity to: (i) measure equity investments at fair value through net income, with certain exceptions; (ii) present in Other Comprehensive Income the changes in instrument-specific credit risk for financial liabilities measured using the fair value option; (iii) present financial assets and financial liabilities by measurement category and form of financial asset; (iv) calculate the fair value of financial instruments for disclosure purposes based on an exit price and; (v) assess a valuation allowance on deferred tax assets related to unrealized losses of AFS debt securities in combination with other deferred tax assets. The Update provides an election to subsequently measure certain nonmarketable equity investments at cost less any impairment and adjusted for certain observable price changes. The Update also requires a qualitative impairment assessment of such equity investments and amends certain fair value disclosure requirements. The new standard becomes effective for fiscal years beginning after December 15, 2017. Early adoption is only permitted for the provision related to instrument-specific credit risk and the fair value disclosure exemption provided to nonpublic entities. The Company is currently evaluating the effects of adopting ASU 2016-01 on its consolidated financial statements but the adoption is not expected to have a significant impact on the Company's consolidated financial statements.

ASU No. 2016-02: Leases (Topic 842). In February 2016, FASB issued ASU 2016-02 which aims to increase transparency and comparability among organizations by recognizing lease assets and lease liabilities on the balance sheet and requiring disclosure of key information about leasing agreements. Entities are required to recognize and measure leases at the beginning of the earliest period presented using a modified retrospective approach. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. Early adoption is permitted. The Company is currently evaluating the effects of adopting ASU 2016-02 on its consolidated financial statements, but the adoption is not expected to have a significant impact on the Company's financial statements.

NOTE 2 - OIL AND GAS PROPERTIES, EQUIPMENT AND FIXTURES

Oil and gas properties, equipment and fixtures consist of the following at December 31:

	2017	2016
Oil and Gas		
Producing properties, including intangible drilling costs	$ 3,755,705	$ 3,755,705
Undeveloped properties	1,435	307,158
Lease and well equipment	4,119,802	4,128,178
	7,876,942	8,191,041
Accumulated depletion, depreciation and amortization	(6,582,648)	(6,468,279)
	$ 1,294,294	$ 1,722,762
Commercial and Other	2017	2016
Real estate, including furniture and fixtures	$ -	$ -
Vehicles	40,061	40,061
Furniture and equipment	1,092,926	1,089,648
	1,132,987	1,129,709
Accumulated depreciation	(1,125,039)	(1,119,047)
	7,948	10,662
	$ 1,302,242	$ 1,733,424

The following sets forth costs incurred for oil and gas property acquisition and development activities, whether capitalized or expensed:

		2017	2016
Acquisition - Proved	$	-	-
Acquisition- Unproved	$	-	-
Development	$	4,525,452	1,210,261
Exploration	$	-	2,603,209

The guidance set forth in the Continued Capitalization of Exploratory Well Costs paragraph of the Extractive Activities Topic of the FASB Accounting Standards Codification requires that we evaluate all existing capitalized exploratory well costs and disclose the extent to which any such capitalized costs have become impaired and are expensed or reclassified during a fiscal period. We did not make any additions to capitalized exploratory well costs pending a determination of proved reserves during 2017 or 2016. We did not charge any previously capitalized exploratory well costs to expense upon adoption of Topic. Undeveloped properties are not subject to depletion, depreciation or amortization.

	12 Months Ended December 31,			
		2017		2016
Beginning balance at January 1	$	-	$	-
Additions to capitalized exploratory well costs pending the determination of proved reserves	$	-	$	-
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	$	-	$	-
Ending balance at December 31	$	-	$	-

Results of Operations from Oil and Gas Producing and Exploration Activities

The results of operations from oil and gas producing and exploration activities (excluding corporate overhead and interest costs) for the two years ended December 31, are as follows:

		2017	2016
Oil and gas sales	$	554,235	538,631
Production related costs		(435,637)	(594,241)
Lease Impairment		(289,775)	(2,071,849)
Depreciation, depletion and amortization		(116,017)	(283,874)
Results of operations from producing and exploration activities	$	(287,194)	(2,411,333)
Income Taxes (Benefit)		-	-
Net Results	$	(287,194)	(2,411,333)

NOTE 3 - ASSET RETIREMENT OBLIGATION

The Asset Retirement and Environmental Obligations Topic of the FASB Accounting Standards Codification requires that an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset be recognized as a liability in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset. The ARO is recorded at fair value, and accretion expense will be recognized over time as the discounted liability is accreted to its expected settlement value. The fair value of the ARO is measured using expected future cash outflows discounted at the Company's credit-adjusted risk-free interest rate. The provisions of this Topic apply to legal obligations associated with the retirement of long-lived assets that result from the acquisition, development, and operation of a long-lived asset.

	2017	2016
Asset retirement obligation, Beginning of the year	$ 952,110	$ 1,096,179
Liabilities incurred during the period	53,142	90,000
Settlements	-	(10,498)
Sales	-	(229,465)
Accretion expense	(4,344)	5,894
Asset retirement obligation, End of year	$ 1,000,908	$ 952,110

NOTE 4 - TURNKEY DRILLING OBLIGATION

Royale Energy receives funds under turnkey drilling contracts, which require Royale Energy to drill oil and gas wells within a reasonable time period from the date of receipt of the funds. As of December 31, 2017 and 2016, Royale Energy had recorded deferred turnkey drilling associated with undrilled wells of $5,891,898 and $7,894,001, respectively, as a current liability.

NOTE 5 - LONG-TERM DEBT

	2017	2016
	$ -	$ -
Total Long Term Debt	$ -	$ -
Less Current Maturity	-	$ -
Long Term Debt Less Current Portion	$ -	$ -

NOTE 6 - INCOME TAXES

Deferred tax assets and liabilities reflect the net tax effect of temporary differences between the carrying amount of assets and liabilities for financial reporting purposes and amounts used for income tax purposes. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. Deferred tax assets and liabilities are adjusted for the effects of changes in tax laws and rates on the date of enactment. In 2016, the Company adopted Accounting Standards Update (ASU) 2015-17 and has classified all of its deferred tax assets and liabilities as noncurrent on its balance sheet.

On December 22, 2017, the U.S. enacted significant changes to U.S. tax law following the passage and signing of H.R.1, "An Act to Provide for Reconciliation Pursuant to Titles II and V of the Concurrent Resolution on the Budget for Fiscal Year 2018 (the "Tax Act"). The Tax Act permanently reduces the U.S. federal corporate tax rate from a maximum 35% to 21%, eliminated corporate Alternative Minimum Tax, modified rules for expensing capital investment, and limits the deduction of interest expense for certain companies. Accounting Standard Codification ("ASC") 740 requires filers to record the effect of tax law changes in the period enacted. However, the SEC issued Staff Accounting Bulletin No. 118 ("SAB 118"), that permits filers to record provisional amounts during a measurement period ending no later than one year from the date of enactment. For the period ending December 31, 2017, the Company re-measured the applicable deferred tax assets based on the rates at which they are expected to reverse. The gross deferred tax assets and liabilities have been adjusted and a corresponding offset has been recorded to the full valuation allowance against the Company's net deferred tax assets, which resulted in no net effect to its provision for income taxes and effective tax rate. No other provisional adjustments have been made as a result of the Act.

Significant components of the Company's deferred assets and liabilities at December 31, 2017 and 2016, respectively, are as follows:

	2017	2016
Deferred Tax Assets (Liabilities):		
Statutory Depletion Carry Forward	$ 369,591	$ 474,250
Net Operating Loss	3,130,841	5,392,208
Other	1,013,329	1,255,372
Share-Based Compensation	69,609	104,388
Capital Loss / AMT Credit Carry Forward	18,915	18,915
Charitable Contributions Carry Forward	10,025	13,102
Allowance for Doubtful Accounts	514,067	886,056
Oil and Gas Properties and Fixed Assets	4,839,823	5,922,031
	$ 9,966,200	$ 14,066,322
Valuation Allowance	(9,966,200)	(14,066,322)
Net Deferred Tax Asset	$ -	$ -

At the end of 2016, management reviewed the realizability of the Company's net deferred tax assets. Due to the Company's cumulative losses in recent years, Royale and its management concluded that it is not "more-likely-than-not" its deferred tax assets will be realized. As a result, the Company recorded a full valuation allowance against the net deferred tax assets in 2016. At the end of 2017, management reviewed the reliability of the Company's net deferred tax assets, and due to the Company's continued cumulative losses in recent years, Royale and its management concluded it is not "more-likely-than-not" its deferred tax assets will be realized. As a result, the Company will continue to record a full valuation allowance against the deferred tax assets in 2017. The Company will assess the realizability of the deferred tax assets at least yearly and make appropriate updates as needed. The Company had statutory percentage depletion carry forwards of approximately $1.4 million at December 31, 2017. The depletion has no expiration date. The Company also has a net operating loss carry forward of approximately $12.0 million at December 31, 2017, which will begin to expire in 2027.

A reconciliation of Royale Energy's provision for income taxes and the amount computed by applying the statutory income tax rates at December 31, 2017 and 2016, respectively, to pretax income is as follows:

	2017	2016
Tax (benefit) computed at statutory rate of 34%	$ (825,237)	$ (1,400,617)
Increase (decrease) in taxes resulting from:		
State tax / percentage depletion / other	990	937
Other non-deductible expenses	403	624
Change in valuation allowance	823,844	1,399,056
Provision (benefit)	$ -	$ -

The components of the Company’s tax provision are as follows:

		2017	2016
Current tax provision (benefit) – federal	$	-	-
Current tax provision (benefit) – state		-	-
Deferred tax provision (benefit) – federal		-	-
Deferred tax provision (benefit) – state		-	-
Total provision (benefit)	$	-	-

In January 2007, Royale adopted additional provisions from the Income Taxes Topic of the FASB Accounting Standards Codification, which clarified the accounting for uncertainty in income taxes recognized in an entity’s financial statements and prescribes a recognition threshold and measurement attribute for financial statement disclosure of tax positions taken or expected to be taken on a tax return. As a result of our implementation of the Topic at the time of adoption and at December 31, 2017, the Company did not recognize a liability for uncertain tax positions. Currently, the only differences between our financial statements and our income tax returns relate to normal timing differences such as depreciation, depletion and amortization, which are recorded as deferred taxes on our balance sheets. We do not expect our unrecognized tax benefits to change significantly over the next 12 months. The tax years 2012 through 2016 remain open to examination by the taxing jurisdictions in which we file income tax returns.

NOTE 7 - SERIES AA PREFERRED STOCK

In April 1992, Royale Energy’s Board of Directors authorized the sale of 147,500 shares of Series AA Convertible Preferred Stock. The resolution authorizing the Series AA Convertible Preferred Stock provided for a stated value of $4 per share. The Series AA Convertible Preferred Stock is convertible at the option of the security holder at the rate of one share of common stock for two shares of Series AA Convertible Preferred Stock. The Series AA Preferred Stock has never been registered under the Securities Exchange Act of 1934, and no market exists for the shares. No shares of Series AA Preferred Stock have been issued since the original shares were issued in 1992.

As of September 30, 2016, Royale Energy’s transfer records reflected that certificates representing 46,662 shares of Series AA Preferred stock remained outstanding, but Royale Energy has lost contact with the registered holders of the Series AA Preferred Stock and does not have a means to communicate with them concerning the status of their shares.

In November 2016, Royale entered into a securities purchase agreement with one vendor for the settlement an outstanding accounts payable of $25,000. Under the terms of the agreement, Royale issued 76,923 shares of its Series AA convertible preferred stock at $0.325 per share. On the basis of a resolution by the Board of Directors’, these Series AA shares were immediately converted to common stock on a one to one basis.

In late 2016, Royale Energy learned that the records of the Secretary of State of California do not reflect that a certificate of determination, amendment to the company’s articles of incorporation, or any other document had ever been filed with the Secretary of State authorizing the issuance of the Series AA Preferred Stock. Royale Energy has reserved 23,331 shares of its common stock (the amount of common stock into which the Series AA Preferred shares would be convertible) for issuance to holders of the outstanding certificates for Series AA Preferred Stock at such time as Royale Energy is able to make contact with the Series AA Preferred shareholders.

NOTE 8 - COMMON STOCK

In April 2016, Royale entered in a securities purchase agreement and related agreements with one investor. Under the terms of the agreement, the investor purchased 622,316 shares of Royale’s common stock at $0.3214 per share, and received warrants to purchase up to 311,158 shares (the “Warrants’) of stock at $0.5356 per share for three (3) years, for a total of $200,000 in gross proceeds. In July 2016, Royale entered in securities purchase agreements and related agreements with three investors. Under the terms of the agreement, the investors purchased 2,392,500 shares of Royale’s common stock at $0.40 per share, and received warrants to purchase up to 478,500 shares (the “Warrants’) of stock at $0.80 per share for two (2) years, for a total of $957,000 in gross proceeds.

On November 25, 2015, Royale Energy entered into a securities purchase agreement and related agreements with a group of individual investors pursuant to a registered direct offering. Under the terms of the agreements, the investors purchased 497,948 shares of Royale's common stock at $0.408 per share, and received warrants to purchase up to 248,973 shares (the "Warrants') of stock at $1.00 per share for three (3) years, for a total of $203,165 in gross proceeds, Each Warrant becomes exercisable one year from the date of issuance. Each Warrant contains customary adjustments for corporate events such as reorganizations, splits, and dividends. The fair value of each warrant was estimated on the grant date using the Black-Scholes option-pricing model. This model incorporates certain assumptions for inputs including a risk-free market interest rate, expected dividend yield of the underlying common stock, expected warrant life and expected volatility in the market value of the underlying common stock. For these warrants, the value was calculated with the following assumptions: expected volatility of 78.96%, risk-free market interest rate of 1.13%, an expected term of 1,460 days, and an exercise price of $1.00.

NOTE 9 - OPERATING LEASES

Royale Energy occupies office space through the use of two leases, one for their office in El Cajon, CA and one for an office and yard in Woodland, CA. The El Cajon lease is under a 62 month lease contract, with a yearly increase of 3.5%, which expires in January 2020. The El Cajon lease calls for monthly payments ranging from $6,148 to $10,801, and the Woodland lease calls for monthly payments of $500. Royale rents an office and yard in Woodland, CA on a month-to-month basis that currently calls for monthly payments of $500. Rental expense for the years ended December 31, 2017 and 2016 was $110,909 and $63,733 respectively.

Year Ended December 31,		
2018	$	119,286
2019	$	123,251
2020	$	127,355
2021	$	131,602
2022	$	13,802
Total	$	515,296

NOTE 10 - RELATED PARTY TRANSACTIONS

Significant Ownership Interests

Harry E. Hosmer, Royale Energy's chairman of the board of directors, is the father of Royale Energy executives Donald H. Hosmer, president of business development and director; and Stephen M. Hosmer, chief financial officer and director.

As of February 27, 2018, Donald H. Hosmer owned 6.75% of Royale Energy common stock (as calculated under SEC Rule 13d-3). Donald Hosmer has participated individually in 179 wells under the 1989 policy. During 2017, Donald did not participate in fractional interests and in 2016 participated in fractional interests of one well in the amount of $1,556. At December 31, 2017, Royale had a payable balance of $340 due to Donald Hosmer for normal drilling and lease operating expenses.

As of February 27, 2018, Stephen M. Hosmer owned 6.32% of Royale Energy common stock (as calculated under SEC Rule 13d-3). Stephen Hosmer has participated individually in 179 wells under the 1989 policy. During 2017, Stephen did not participate in fractional interests and in 2016 participated in fractional interests of one well in the amount of $1,556. At December 31, 2017, Royale had a receivable balance of $11,817 due from Stephen Hosmer for normal drilling and lease operating expenses.

As of February 27, 2018, Harry E. Hosmer owned 7.09% of Royale Energy common stock (as calculated under SEC Rule 13d-3). During 2017, Harry Hosmer did not participate in fractional interests and in 2016 participated in fractional interests of one well in the amount of $1,556. At December 31, 2017, Royale had a receivable balance of $3,999 due from Harry Hosmer for normal drilling and lease operating expenses.

NOTE 11 - <u>STOCK COMPENSATION PLAN</u>

A summary of the status of Royale Energy's stock option plan as of December 31, 2017 and 2016, and changes during the years ending on those dates is presented below:

	2017			2016		
	Shares		Weighted-Average Exercise Price	Shares		Weighted-Average Exercise Price
Options						
Outstanding and Exercisable at Beginning of Year	100,000	$	5.00	100,000	$	5.00
Granted or Vested	-		-	-		-
Exercised	-		-	-		-
Forfeited	(100,000)		-	-		-
Options Outstanding and Exercisable at Year End	-	$	-	100,000	$	5.00
Weighted-average Fair Value of Options Granted During the Year	-			-		

At December 31, 2016, Royale Energy's stock price, $0.62, was less than the weighted average exercise price, and as such the outstanding and exercisable stock options had no intrinsic value. The remaining outstanding stock options have a weighted-average remaining contractual term of one year as of December 31, 2016. There were no stock options granted during 2017.

A summary of the status of Royale Energy's non-vested stock options as of December 31, 2017 and 2016, and changes during the years ending on those dates is presented below:

	2017			2016		
	Shares		Weighted-Average Grant-Date Fair Value	Shares		Weighted-Average Grant-Date Fair Value
Non-vested Stock Options						
Non-vested at Beginning of Year	-	$	-	-	$	-
Granted	-		-	-		-
Reinstated	-		-	-		-
Vested	-		-	-		-
Expired or Forfeited	-		-	-		-
Non-vested at End of Year	-	$	-	-	$	-

During 2017 and 2016, we recognized $0 and $0, respectively, in compensation costs for the vested stock options. The company will incur no future expense related to these options.

NOTE 12 - <u>SIMPLE IRA PLAN</u>

In April 1998, the Company established a Simple IRA pension plan covering all employees. The Company will contribute a matching contribution to each eligible employee's Simple IRA equal to the employee's salary reduction contributions up to a limit of 3% of the employee's compensation for the year. The employer contribution for the years ending December 31, 2017 and 2016, were $28,967 and $29,011 respectively.

NOTE 13 - ENVIRONMENTAL MATTERS

Royale Energy has established procedures for the continuing evaluation of its operations to identify potential environmental exposures and assure compliance with regulatory policies and procedures. Management monitors these laws and regulations and periodically assesses the propriety of its operational and accounting policies related to environmental issues. The nature of Royale Energy's business requires routine day-to-day compliance with environmental laws and regulations. Royale Energy incurred no material environmental investigation, compliance and remediation costs in 2017 or 2016.

Royale Energy is unable to predict whether its future operations will be materially affected by these laws and regulations. It is believed that legislation and regulations relating to environmental protection will not materially affect the results of operations of Royale Energy.

NOTE 14 - CONCENTRATIONS OF CREDIT RISK

The Company bids its gas sales on a month to month basis and generally sells to a single customer without commitment to future gas sales to any particular customer. The Company normally sells approximately 32% of its monthly natural gas production to one customer on a month to month basis. Since we are able to sell our natural gas to other readily available customers, the loss of any one customer would not have an adverse effect on our overall sales operations.

The Company maintains cash in depository institutions that are guaranteed by the Federal Deposit Insurance Corporation (FDIC) up to $250,000 per institution for our interest bearing accounts in the years ended December 31, 2017, and 2016. At December 31, 2016, and 2015, the Company's non-interest bearing accounts were fully insured by the FDIC. At December 31, 2017 and 2016, cash in banks exceeded the FDIC limits by approximately $2.8 million and $4.5 million, respectively. The Company has not experienced any losses on deposits.

NOTE 15 - COMMITMENTS AND CONTINGENCIES

The Company may become involved from time to time in litigation on various matters, which are routine to the conduct of its business. The Company believes that none of these actions, individually or in the aggregate, will have a material adverse effect on its financial position or results of operations, though any adverse decision in these cases or the costs of defending or settling such claims could have a material effect on its business.

NOTE 16 - CHANGE IN ESTIMATE

During the year 2016, the Company changed the process by which it analyzed the collectability of its other receivables, mainly from direct working interest investors. S*ee Note 1, Other Receivables*. Prior to 2016, the Company estimated the collectability of its receivables on a well by well basis, based on its reserve report furnished by the Company's independent petroleum engineers. The reserve report provided an estimate of future revenues to be recovered from existing wells which was then compared to the receivables from those wells. An allowance for doubtful accounts was established if the receivables exceeded the future revenues. In 2016, the Company applied its reserve report values proportionally to its direct working interest investors to determine the potentially uncollectable amount on a per investor basis.

NOTE 17 - SUBSEQUENT EVENTS

On August 2, 2016, the Company issued two unsecured convertible promissory notes for a total principal amount of $1,580,000 to two investors. See Capital Resources and Liquidity, page 12. On August 2, 2017, the notes became due and payable and remained due and payable on December 31, 2017. On February 28, 2018, one of the notes, for $300,000, was converted to 750,000 shares of common stock immediately prior to the Merger (a conversion price of $0.40 per share). Also on February 28, 2018, Royale reached a settlement of a dispute with the second investor regarding his advance of $1.28 million. In the settlement, Royale has agreed to pay $1.9 million to the investor, who in turn did not receive shares of the Company's common stock on conversion of this investment. At December 31, 2017, Legal and Accounting expense includes a $438,667 litigation settlement, the difference between the $1.9 million settlement and the original note of $1.28 million and accrued interest of $181,333. In the settlement, Royale also cancelled a two year warrant issued to the second investor to purchase 1,066,667 of Royale common stock at $0.80 per share.

On March 7, 2018, New Royale, Royale, and Matrix and its affiliates were notified by the California Secretary of State of the filing and acceptance of agreements of merger by the California Secretary of State, to complete the previously announced merger between the companies (the "Merger"), as described in Item 1 – Description of Business – Merger with Matrix Oil Management Corporation.

NOTE 18 - SUPPLEMENTAL INFORMATION ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests owned by Royale Energy which are located solely in the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate to be reasonably certain to be recoverable in the future from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells, with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

Disclosures of oil and gas reserves, which follow, are based on estimates prepared by independent petroleum engineering consultant Netherland, Sewell & Associates, Inc., the net reserve value of its proved developed and undeveloped reserves was approximately $3.0 million at December 31, 2016, based on the average PG&E city-gate natural gas price spot price of $2.76 per MCF and for oil volumes, the average West Texas Intermediate price of $39.25 per barrel as applied on a field-by-field basis. Netherland, Sewell & Associates, Inc. provided reserve value information for the Company’s California, Texas, Oklahoma, Utah and Louisiana properties. Such estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. These estimates do not include probable or possible reserves.

The technical persons responsible for preparing the reserves estimates presented in the report of Netherland, Sewell & Associates, Inc., meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Netherland, Sewell & Associates, Inc. is a firm of independent petroleum engineers, geologists, geophysicists, and petrophysicists; and do not own an interest in our properties and are not employed on a contingent basis. All activities and reports performed and completed by Netherland, Sewell & Associates, Inc. with regards to our reserve valuation estimates are reviewed Royale’s management.

These estimates are furnished and calculated in accordance with requirements of the Financial Accounting Standards Board and the Securities and Exchange Commission (SEC). Because of unpredictable variances in expenses and capital forecasts, crude oil and natural gas price changes, largely influenced and controlled by U.S. and foreign government actions, and the fact that the bases for such estimates vary significantly, management believes the usefulness of these projections is limited. Estimates of future net cash flows presented do not represent management’s assessment of future profitability or future cash flows to Royale Energy. Management’s investment and operating decisions are based upon reserve estimates that include proved reserves prescribed by the SEC as well as probable reserves, and upon different price and cost assumptions from those used here.

It should be recognized that applying current costs and prices and a 10 percent standard discount rate does not convey absolute value. The discounted amounts arrived at are only one measure of the value of proved reserves.

Changes in Estimated Reserve Quantities

The net interest in estimated quantities of proved developed reserves of crude oil and natural gas at December 31, 2017 and 2016, and changes in such quantities during each of the years then ended, were as follows:

	2017		2016	
	Oil (BBL)	Gas (MCF)	Oil (BBL)	Gas (MCF)
Proved developed and undeveloped reserves:				
Beginning of period	5,853	2,014,921	3,600	2,510,700
Revisions of previous estimates	(5,549)	307,371	2,446	74,983
Production	(102)	(190,111)	(193)	(232,539)
Extensions, discoveries and improved recovery	-	40	-	112,265
Purchase of minerals in place	-	-	-	-
Sales of minerals in place	-	-	-	(450,488)
Proved reserves end of period	202	2,132,221	5,853	2,014,921

	2017		2016	
	Oil (BBL)	Gas (MCF)	Oil (BBL)	Gas (MCF)
Proved developed reserves:				
Beginning of period	5,823	1,699,997	-	2,174,100
End of period	202	1,798,697	5,823	1,699,997

	2017		2016	
	Oil (BBL)	Gas (MCF)	Oil (BBL)	Gas (MCF)
Proved undeveloped reserves:				
Beginning of period	-	314,925	3,600	336,600
End of period	-	333,524	-	314,925

For December 31, 2017, our previously estimated proved developed and undeveloped reserve quantities were revised upward by approximately 307,371 MCF of natural gas. This upward revision reflected higher than previously estimated proved producing and non-producing natural gas reserves at eight California wells and one Utah well. A location which had 63,350 MCF in proved developed reserves at December 31, 2016, was drilled and began in 2011, was revised upward 122,998 MCF at December 31, 2017. Two locations which had 128,165 MCF in proved developed reserves at December 31, 2016, were drilled and began producing prior to 2000, were revised upward 118,006 MCF at December 31, 2017. A location which was drilled and began producing in 2010, which had proved developed reserves of 618,709 was revised upward 15,227 MCF at December 31, 2017. A location in Utah which was drilled and began producing in 2006, was revised upward 14,688 MCF at December 31, 2017. A location which was drilled and began producing in 2012, had no proved developed reserves at December 31, 2016, was revised upward 10,994 MCF at December 31, 2017. A location which was drilled and began producing in 2008, had proved developed reserves of 13,878 at December 31, 2016, was revised upward 6,084 MCF at December 31, 2017. A location which had proved undeveloped reserves of 314,925 MCF at December 31, 2016, was revised upward 18,598 MCF at December 31, 2017.

For December 31, 2016, natural gas extensions, discoveries and improved recovery were 112,265 MCF which was added due to the drilling of two new exploratory wells and one new developmental well during 2016. The three new wells consisted of 99,762 MCF of proved developed producing reserves at year end. A location which had 187,500 MCF in proved developed reserves at December 31, 2015, was drilled and began producing prior to 2000, was revised downward 150,609 MCF at December 31, 2016. A location which was drilled and began producing in 2009, which had proved developed reserves of 400,400 was revised upward 71,607 MCF at December 31, 2016. A location which was drilled and began producing in 2015, was revised downward 44,600 MCF at December 31, 2016. A location which was drilled and began producing in 2010, had proved developed reserves of 592,700 at December 31, 2015, was revised upward 31,843 MCF at December 31, 2016. A location which was drilled and began producing in 2015, which had proved undeveloped reserves of 16,900, was revised upward 20,099 MCF at December 31, 2016. Four locations which were drilled prior to 2015, had a total of 249,500 MCF of proved developed reserves at December 31, 2015, were revised upward 37,181 MCF at December 31, 2016. Additionally in 2016, two locations which were drilled prior to 2009, were revised upward 44,175 MCF at December 31, 2016.

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

The standardized measure of discounted future net cash flows is presented below for the two years ended December 31, 2017.

The future net cash inflows are developed as follows:

- Estimates are made of quantities of proved reserves and the future periods during which they are expected to be produced based on year-end economic conditions.
- The estimated future production of proved reserves is priced on the basis of year-end prices.
- The resulting future gross revenue streams are reduced by estimated future costs to develop and to produce proved reserves, based on year-end estimates. Estimated future development costs by year are as follows:

2018	$	103,300
2019		342,700
2020		-
Thereafter		134,800
Total	$	580,800

The resulting future net revenue streams are reduced to present value amounts by applying a ten percent discount.

Disclosure of principal components of the standardized measure of discounted future net cash flows provides information concerning the factors involved in making the calculation. In addition, the disclosure of both undiscounted and discounted net cash flows provides a measure of comparing proved oil and gas reserves both with and without an estimate of production timing. The standardized measure of discounted future net cash flow relating to proved reserves reflects estimated income taxes.

<u>Changes in standardized measure of discounted future net cash flow from proved reserve quantities</u>

This statement discloses the sources of changes in the standardized measure from year to year. The amount reported as "Net changes in prices and production costs" represents the present value of changes in prices and production costs multiplied by estimates of proved reserves as of the beginning of the year. The "accretion of discount" was computed by multiplying the ten percent discount factor by the standardized measure on a pretax basis as of the beginning of the year. The "Sales of oil and gas produced, net of production costs" are expressed in actual dollar amounts. "Revisions of previous quantity estimates" is expressed at year-end prices. The "Net change in income taxes" is computed as the change in present value of future income taxes.

		2017	**2016**
Future cash inflows	$	6,065,500	5,270,400
Future production costs		(2,117,900)	(1,744,200)
Future development costs		(580,800)	(556,500)
Future income tax expense		(1,010,040)	(890,910)
Future net cash flows		2,356,760	2,078,790
10% annual discount for estimated timing of cash flows		(712,072)	(595,518)
Standardized measure of discounted future net cash flows	$	1,644,688	1,483,272
Sales of oil and gas produced, net of production costs	$	(161,139)	(55,272)
Revisions of previous quantity estimates		87,956	120,833
Net changes in prices and production costs		106,303	(253,313)
Sales of minerals in place		-	(402,900)
Purchases of minerals in place		-	-
Extensions, discoveries and improved recovery		74	184,476
Accretion of discount		197,400	296,970
Net change in income tax		(69,178)	32,762
Net increase (decrease)	$	161,416	(76,444)

Future Development Costs

In order to realize future revenues from our proved reserves estimated in our reserve report, it will be necessary to incur future costs to develop and produce the proved reserves. The following table estimates the costs to develop and produce our proved reserves in the years 2018 through 2020.

Future development cost of:	2018	2019	2020
Proved developed reserves	$ -	$ -	$ -
Proved non-producing reserves	103,300	-	-
Proved undeveloped reserves	-	342,700	-
Total	$ 103,300	$ 342,700	$ -

Common assumptions include such matters as the real extent and average thickness of a particular reservoir, the average porosity and permeability of the reservoir, the anticipated future production from existing and future wells, future development and production costs and the ultimate hydrocarbon recovery percentage. As a result, oil and gas reserve estimates and discounted present value estimates are frequently revised in subsequent periods to reflect production data obtained after the date of the original estimate. If the reserve estimates are inaccurate, production rates may decline more rapidly than anticipated, and future production revenues may be less than estimated.

Additional data relating to Royale Energy's oil and natural gas properties is disclosed in Supplemental Information About Oil and Gas Producing Activities (Unaudited), attached to Royale Energy's Financial Statements, beginning on page F-1.

Historic Development Costs for Proved Reserves

In each year we expend funds to drill and develop some of our proved undeveloped reserves. The following table summarizes our historic costs incurred in each of the past three fiscal years to drill and develop reserves that were classified as proved undeveloped reserves as of December 31 of the immediately preceding year:

2017	$ -
2016	$ 243,583
2015	$ -

Exhibit 21.1

ROYALE ENERGY, INC.
SUBSIDIARIES
December 31, 2017

Royale DWI Investors, LLC, a California limited liability company.

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in this Registration Statement on Form S-3 of Royale Energy Funds, Inc. of our report dated March 23, 2018, relating to the financial statements, appearing in the Annual Report on Form 10-K of Royale Energy, Inc. for the year ended December 31, 2017, and incorporated by reference in Registration Statement on Form S-3.

SingerLewak LLP

Los Angeles, California
March 23, 2018

Exhibit 31.1

I, Jonathan Gregory, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy Funds, Inc.;

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 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.

Date: March 23, 2018

/s/ Jonathan Gregory

Jonathan Gregory, Chief Executive Officer

Exhibit 31.2

I, Donald H. Hosmer, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy Funds, Inc.;

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 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.

Date: March 23, 2018

/s/ Donald H. Hosmer

Donald H. Hosmer, President of Business Development

Exhibit 31.3

I, Stephen M. Hosmer, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy Funds, Inc.;

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 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.

Date: March 23, 2018

/s/ Stephen M. Hosmer
Stephen M. Hosmer, President and Chief Financial Officer

Exhibit 32.1

Certification Pursuant to 18 U.S.C. § 1350

The undersigned, Jonathan Gregory, Chief Executive Officer of Royale Energy Funds, Inc., a California corporation (the "Company"), pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, hereby certifies that:

(1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) 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 Company.

Date: March 23, 2018

By: */s/ Jonathan Gregory*
Jonathan Gregory, Chief Executive Officer

Exhibit 32.2

Certification Pursuant to 18 U.S.C. § 1350

The undersigned, Donald H. Hosmer, Co-President and Co-Chief Executive Officer of Royale Energy Funds, Inc., a California corporation (the “Company”), pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, hereby certifies that:

(1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2017 (the “Report”) fully complies with the requirements of Section 13(a) 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 Company.

Date: March 23, 2018

By: */s/ Donald H. Hosmer*
Donald H. Hosmer, President of Business Development

Exhibit 32.3

Certification Pursuant to 18 U.S.C. § 1350

The undersigned, Stephen M. Hosmer, Co-President, Co-Chief Executive Officer and Chief Financial Officer of Royale Energy Funds, Inc., a California corporation (the "Company"), pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002, hereby certifies that:

(1) the Company's Annual Report on Form 10-K for the year ended December 31, 2017 (the "Report") fully complies with the requirements of Section 13(a) 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 Company.

Date: March 23, 2018

By: */s/ Stephen M. Hosmer*
Stephen M. Hosmer, President and Chief Financial Officer

February 14, 2018

Mr. Stephen M. Hosmer
Royale Energy, Inc.
1870 Cordell Court, Suite 210
El Cajon, California 92020

Dear Mr. Hosmer:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2017, to the Royale Energy, Inc. (Royale) interest in certain oil and gas properties located in California, Louisiana, Oklahoma, Texas, and Utah. 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 Royale. 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 Royale'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 Royale interest in these properties, as of December 31, 2017, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	0.2	193.0	122.3	109.0
Proved Developed Non-Producing	0.0	1,605.7	2,880.1	1,646.0
Proved Undeveloped	0.0	333.5	364.4	219.1
Total Proved	0.2	2,132.2	3,366.8	1,974.0

Totals may not add because of rounding.

The oil volumes shown include crude oil and condensate. Oil 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.

Reserves categorization conveys the relative degree of certainty; reserves subcategorization is based on development and production status. No study was made to determine whether probable or possible reserves might be established for these properties. The estimates of reserves and future revenue included herein have not been adjusted for risk. 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.

Gross revenue is Royale's share of the gross (100 percent) revenue from the properties prior to any deductions. Future net revenue is after deductions for Royale's share of production taxes, ad valorem taxes, capital 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 2017. For oil volumes, the average West Texas Intermediate posted price of $47.79 per barrel is adjusted by lease for quality, transportation fees, and market differentials. For gas volumes, the average PG&E city-gate spot price of $3.261 per MMBTU is adjusted by lease 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 $46.25 per barrel of oil and $2.840 per MCF of gas.

Operating costs used in this report are based on operating expense records of Royale. 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. Headquarters general and administrative overhead expenses of Royale are included to the extent that they are covered under joint operating agreements for the operated properties. Operating costs are not escalated for inflation.

Capital costs used in this report were provided by Royale and are based on authorizations for expenditure 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. Capital costs are not escalated for inflation. Our estimates do not include any salvage value for the lease and well equipment or the cost of abandoning the properties. It is our understanding that Royale has fully prefunded accounts that meet or exceed its estimates of abandonment costs for the properties, net of any salvage value.

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 Royale 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 Royale receiving its net revenue interest share of estimated future gross production. Additionally, we have made no investigation of any firm transportation contracts that may be in place for these properties; no adjustments have been made to our estimates of future revenue to account for such contracts.

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 Royale, 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, and analogy, 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 and undeveloped locations; 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 Royale, 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. Mr. C. Ashley Smith, a Licensed Professional Engineer in the State of Texas, has been practicing consulting petroleum engineering at NSAI since 2006 and has over 5 years of prior industry experience. Mr. 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

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

/s/ C. Ashley Smith
By:
C. Ashley Smith, P.E. 100560
Vice President

Date Signed: February 14, 2018

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

Date Signed: February 14, 2018

CAS:SMD

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.

(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.

(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

(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.

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.