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, 2023** Commission File No. **000-055912**

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

Delaware	**81-4596368**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1530 Hilton Head Road #205
El Cajon, CA 92019
(Address of principal executive offices)

Registrant'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, 0.001 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 every Interactive Data File required to be submitted 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 such files). Yes ☒ No ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

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. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant’s executive officers during the relevant recovery period pursuant to § 240.10D-1(b). ☐

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, 2023, the end of the registrant’s most recently completed second fiscal quarter; the aggregate market value of Common Stock held by non-affiliates was $1,987,037.

At March 12, 2024, 71,863,829 shares of the registrant’s Common Stock were outstanding.

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ROYALE ENERGY, INC.

PART I

Item 1 Description of Business

Royale Energy, Inc. (“Royale” or the “Company”) is an independent oil and natural gas producer incorporated under the laws of Delaware. Royale’s principal lines of business are the production and sale of oil and 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 Delaware in 2017 and is the successor by merger (as described below) to Royale Energy Funds, Inc., a California corporation formed in 1983. On December 31, 2023, Royale and its consolidated subsidiaries had 10 full time employees.

Royale Business

Royale and its subsidiaries own wells, leases, and proved and non-proved reserves of oil and gas located mainly in Mitchell County and Ector County, Texas and in the Sacramento Basin and San Joaquin Basin in California, as well as in, Oklahoma. Royale also owns an overriding royalty interest in a discovery in Alaska. Royale usually sells a portion of the working interest in each well it drills or participates in to third-party participants 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 typically 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, 2023, Royale continued to explore and develop oil and natural gas properties with concentration in Texas. In 2023, Royale drilled and completed one well and participated in the drilling of three wells, two of which were commercially productive and one that was a dry hole. Royale’s estimated total reserves were approximately 1.8 and 3.4 BCFE (billion cubic feet equivalent) at December 31, 2023 and 2022, respectively. According to the reserve reports furnished by Netherland, Sewell & Associates, Inc., Royale’s independent petroleum engineers, the net reserve value of its proved developed and undeveloped reserves was approximately $10.7 million at December 31, 2023, based on the average Henry Hub natural gas price spot price of $2.637 per MCF and for oil volumes, the average West Texas Intermediate price of $78.21 per barrel as applied on a field-by-field basis. Netherland, Sewell & Associates, Inc. supplied reserve value estimates for the Company’s California, Texas, and Oklahoma properties.

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, 2023, was estimated to be $4,471,896. 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 Note 15 to our Financial Statements, Supplemental Information about Oil and Gas Producing Activities (Unaudited) – Changes in Standardized Measure of Discounted Future Net Cash Flow from Proved Reserve Quantities.

Royale reported a gain on turnkey drilling in connection with the drilling of wells on a “turnkey contract” basis in the amount of $2,107,500 for the year ended December 31, 2023. For the year ended December 31, 2022, Royale reported a gain on turnkey drilling in the amount of $1,726,414.

In addition to Royale’s own staff, Royale hires independent contractors to drill, test, complete and equip the wells that it drills. Approximately 98% of Royale’s total revenue for the year ended December 31, 2023, came from sales of oil and natural gas from production of its wells in the amount of $2,114,026. In 2022, this amount was $2,611,222, which represented 98.8% of Royale’s total revenues for the respective periods presented. See Note 2 to our Financial Statements.

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 private placement sale of working interest in certain oil and gas properties, 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 required 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 undeveloped 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 does 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 we incur 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 commenced, drilling is generally completed within 10-30 days. Royale maintains internal records of the expenditure of each investor’s funds for drilling projects.

Royale generally operates the wells it completes. As operator, we receive fees set by industry standards from the owners of fractional interests in the wells and from expense reimbursements. For the year ended December 31, 2023, Royale charged overhead from the operation of the wells in the amount of $401,233 for the year, which were an offset to general and administrative expenses. In 2022, the amount was $355,681. At December 31, 2023, Royale operated wells in California and Texas. Royale also has non-operating interests in wells in California, Texas, and Oklahoma.

Royale currently sells most of its California natural gas production through Pacific Gas & Electric (“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. Oil demand is subject to global demand and prices can fluctuate widely. In mid-2022, oil prices increased dramatically due to worldwide speculation caused by Russia’s invasion of Ukraine, but by the end of 2022 had returned to pre-invasion levels. The future market is likely to be subject to continued similar price dynamics. 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.

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. On September 16, 2022, the Governor of California, Gavin Newsom, signed Senate Bill No. 1137 ("SB1137") into law. SB1137 prohibits the issuance of well permits and the construction and operation of new production facilities within a "health protection zone" of 3,200 feet from certain sensitive (receptors such as homes, schools, nursing homes, or hospitals). We and our industry partner, RMX Resources, LLC ("RMX") operate wells, production facilities, and future drilling located within a health protection zone. In December 2022, proponents of a voter referendum initiated to challenge SB1137 (the "Referendum") collected the requisite signatures to place SB1137 on the November 2024 ballot. On February 3, 2023, the Secretary of State of California certified that the requisite number of signatures had been submitted and validated for the Referendum to become duly qualified for the November 2024 ballot. By law, the effectiveness of a statute challenged in its entirety by a duly validated Referendum is stayed until it has been approved by the voters at the required election. Thus, the implementation of SB1137's provisions are stayed as of February 3, 2023, until the Referendum challenge has been resolved by a vote of the California electorate on November 5, 2024. If SB 1137 were to be left in effect, it would limit certain undeveloped drilling locations, and significantly deter our participation in future drilling efforts with RMX. Additionally, we cannot predict any future actions the State of California, or other parties, may take that could further limit our ability to drill in certain areas.

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 hold any undeveloped federal acreage on which it had plans to drill, and 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.

Availability of Public Filings

You may obtain a copy of any materials filed by Royale with the Securities and Exchange Commission ("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. The information on our website is not part of this Annual Report on Form 10-K.

Item 1A Risk Factors

As a smaller reporting company, as defined in Rule 12b-2 of the Exchange Act, Royale is not required to provide the information required by this Item.

Item 1B Unresolved Staff Comments

None.

Item 1C Cybersecurity

Risk Management and Strategy

The Company’s cybersecurity environment is led by our information technology (IT) contractor, which, in addition to cybersecurity matters, oversees the Company’s IT infrastructure. The IT contractor is responsible for monitoring and managing the security of the Company's corporate network and enterprise systems, including technical controls, and safety protocols and responding to security threats.

The Company maintains a cybersecurity risk management program that establishes safeguards for protecting the confidentiality, integrity, and availability of our data, technology, and information systems. The program includes general controls for managing changes in and access to the Company’s IT environment, cybersecurity awareness and training to help employees identify and mitigate against cybersecurity threats, cybersecurity incident response plans and third-party incident response retainers to help expedite the Company’s response in the event of a cybersecurity incident.

The Company’s IT contractor is primarily responsible for the day-to-day operation of the Company’s cybersecurity program and for identifying cybersecurity threats and incidents and managing the material risks associated with the cybersecurity threats. The Company’s IT contractor engages third-party vendors and cybersecurity consortiums periodically for cybersecurity-related guidance and certifications. In the event of a cybersecurity incident, the Company’s process calls for the IT contractor, Chief Executive Officer and Chief Financial Officer, work to assess and respond to the incident and provide briefings to the Audit Committee of the Board of Directors.

The Audit Committee is responsible for providing oversight over management's processes to identify and evaluate cybersecurity risks to which the Company is exposed and to implement processes and programs to manage cybersecurity risks and mitigate any incidents. The Audit Committee also reports material cybersecurity risks to the Board. We believe this risk management process provides visibility and oversight to allow the Board and executive leadership team to make timely, data-driven decisions ensuring that the Company, its employees, investors, and partners are adequately protected.

As of and for the year ended December 31, 2023, there have been no cybersecurity incidents that have materially affected the Company’s business strategy, results of operations, or financial condition.

Item 2 Description of Property

Since 1993, Royale had concentrated on development of properties in the Sacramento Basin and the San Joaquin Basin of Northern and Central California. In the last few years it has moved its focus to Mitchell County and Ector County, Texas. In 2023, Royale drilled one developmental oil well in Texas and participated in the drilling of two successful oil wells in Texas and one dry hole in southern 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, 2023, 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 12, 2024.

California

Royale owns interests in nine gas fields with locations ranging throughout the Sacramento Basin in California. At December 31, 2023, Royale operated 12 wells and owns interests in 13 non-operated gas wells in Northern California and 8 non-operated oil wells in Southern and Central California. Our California estimated total proven, developed, and undeveloped net reserves are approximately 0.350 BCFE, according to Royale's independently prepared reserve report as of December 31, 2023.

Texas

At December 31, 2023, Royale owned and operated interests in 26 oil wells in its Jameson field. Additionally, Royale owns interests in four non-operated oil wells in the Permian Basin in Texas and three non-operated gas wells, two located in Oklahoma and one located in Texas. Our Texas estimated total proven, developed, and undeveloped net reserves are approximately 235.4 MBOE, according to Royale's independently prepared reserve report as of December 31, 2023.

Developed and Undeveloped Leasehold Acreage

As of December 31, 2023, 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	2,401.02	1,784.84	3,097.25	996.80
All Other States	7,465.00	7,465.00	0.00	0.00
Total	9,866.02	9,249.84	3,097.25	996.80

Gross and Net Productive Wells

As of December 31, 2023 and 2022, Royale owned interests in the following oil and gas wells in both gross and net acreage:

	2023		2022	
	Gross Wells	Net Wells	Gross Wells	Net Wells
Natural Gas	28	10.8831	29	11.1752
Oil	38	20.8226	33	20.3997
Total	66	31.7057	62	31.5749

Drilling Activities

The following table sets forth Royale's drilling activities during the years ended December 31, 2023 and 2022. All wells are located in the Continental U.S., in California and Texas.

Year	Type of Well(a)		Gross Wells(b)		Net Wells(e)	
		Total	Producing(c)	Dry(d)	Producing(c)	Dry(d)
2022	Exploratory	0	0	0	0	0
	Developmental	7	7	0	1.6781	0
2023	Exploratory	0	0	0	0	0
	Developmental	4	3	1	0.3321	0.5679

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 years 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.

	2023	2022
Net volume		
Oil (BBL)	22,399	18,015
Gas (MCF)	128,160	135,136
MCFE	262,554	243,226
Average sales price		
Oil (BBL)	$ 74.27	$ 91.86
Gas (MCF)	$ 3.47	$ 7.01
Net production costs and taxes	$ 1,731,670	$ 1,928,521
Lifting costs (per MCFE)	$ 6.60	$ 7.93

Reserve Estimates

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that the estimates of Proved Reserves are computed and reported in accordance with rules and regulations promulgated by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls include documented process workflows and qualified professional engineering and geological personnel with specific reservoir experience. Our internal processes and controls surrounding this process are routinely tested. We also retain outside independent engineering firms to prepare estimates of our Proved Reserves. Management reviews and approves our reserve estimates, whether prepared internally or by third parties. Our Chief Executive Officer oversaw our outside independent engineering firm, Netherland, Sewell & Associates, Inc. ("NSAI"), in connection with the preparation of their estimates of our Proved Reserves as of December 31, 2023. We also regularly communicate with NSAI throughout the year regarding technical and operational matters critical to our reserve estimations. Our Chief Executive Officer, with input from other members of management, is responsible for the selection of our third-party engineering firms and review of the reports generated. Our Chief Executive Officer has over 41 years of experience in the oil and natural gas industry and is a graduate of the University of Oklahoma with a degree in Chemical Engineering. During his career, he has had various relevant responsibilities in technical and leadership roles including asset management, drilling and completions, production engineering, reservoir engineering and reserves management, economic evaluations, and field development in U.S. onshore projects. The third-party engineering reports are also provided to the Audit Committee.

Net Proved Oil and Natural Gas Reserves

Category	Oil (MBBL)	Natural Gas (MMCF)
PROVED		
Developed:		
California	32.820	153.050
Texas	105.240	186.780
All other states	-	18.110
Undeveloped:		
California	-	-
Texas	79.720	115.600
All other states	-	-
TOTAL PROVED	**217.780**	**473.540**
Prices used:	$ 78.21	$ 2.64

As of December 31, 2023, Royale had proved developed reserves of 357,940 MCF and total proved reserves of 473,540 MCF of natural gas. For the same period, Royale also had proved developed oil and natural gas liquid combined reserves of 138,060 BBL and total proved oil and natural gas liquid combined reserves of 217,780 BBL.

As of December 31, 2022, Royale had proved developed reserves of 942,000 MCF and total proved reserves of 1,133,300 MCF of natural gas. For the same period, Royale also had proved developed oil and natural gas liquid combined reserves of 182,000 BBL and total proved oil and natural gas liquid combined reserves of 372,300 BBL.

During 2023, our overall proved developed and undeveloped oil reserves decreased by 41.5% and our previously estimated proved developed and undeveloped oil reserve quantities were revised downward by approximately 185 thousand barrels. This downward revision was mainly the result of a decrease in proved undeveloped oil reserves from drilling locations which the Company had previously estimated. Our overall proved developed and undeveloped natural gas reserves decreased by 58.2% and our previously estimated proved developed and undeveloped natural gas reserve quantities were revised downward by approximately 720 thousand cubic feet of natural gas. This downward revision was mainly the result of a decrease in proved undeveloped natural gas reserves from drilling locations which the Company had previously estimated.

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 Legal Proceedings

From time to time, the Company may be involved in various legal proceedings or may be subject to claims that arise in the ordinary course of business. The outcome of any such claims or proceedings cannot be predicted with certainty. As of the date of this filing, management is not aware of any such claims against the Company.

Item 4 Mine Safety Disclosures

Not Applicable

PART II

Item 5 Market for Common Equity and Related Stockholder Matters

There is no established trading market for Royale's Common Stock, which is quoted on the OTC QB Market under the symbol "ROYL." As of December 31, 2023, 70,564,188 shares of Common Stock were held by approximately 3,052 stockholders. As of December 31, 2022, 61,876,957shares of Royale's Common Stock were held by approximately 3,258 stockholders. The following table reflects the high and low quarterly bid prices as reported on the OTC QB Market from January 2022 through December 2023:

	1st Qtr		2nd Qtr		3rd Qtr		4th Qtr	
	High	Low	High	Low	High	Low	High	Low
2022	$ 0.14	$ 0.03	$ 0.10	$ 0.06	$ 0.08	$ 0.06	$ 0.07	$ 0.05
2023	$ 0.06	$ 0.04	$ 0.06	$ 0.04	$ 0.05	$ 0.03	$ 0.04	$ 0.02

The OTC QB Market is not an exchange, and any over the counter quotations reflect inter-dealer prices, without retail markup, markdown or commission, and may not necessarily represent actual transactions.

Transfer Agent

The Company utilizes the independent transfer agent services of American Stock Transfer & Trust Company as its transfer agent.

Dividends

The Board of Directors did not issue cash dividends in either 2023 or 2022. The Board of Directors did declare dividends during 2023 and 2022 on the preferred stock to be Paid In Kind ("PIK") of 84,470 and 81,580 shares with a respective par value of $844,700 and $815,772, as more fully set forth in Note 5 to our Financial Statements.

Recent Sales of Unregistered Securities

None.

Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations

Management's Discussion and Analysis is the Company's analysis of its financial performance and of significant trends that may affect future performance. It should be read in conjunction with the financial statements and notes, and supplemental oil and gas disclosures included elsewhere in this report. It contains forward-looking statements including, without limitation, statements relating to the Company's plans, strategies, objectives, expectations and intentions that are made pursuant to the "safe harbor" provisions of the Private Securities Litigation Reform Act of 1995. Readers are cautioned that such forward-looking statements should be read in conjunction with the Company's disclosures under the heading: "Cautionary Statement about Forward-Looking Statements" in this Annual Report.

Overview

Royale is an independent oil and natural gas producer. Royale's principal lines of business are the production and sale of oil and 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. Since 1993, Royale has primarily acquired and developed producing and non-producing natural gas properties in California. In December 2018, Royale became the operator of a newly acquired field in Texas. The most significant factors affecting the results of operations are (i) changes in oil and natural gas prices, production levels and reserves, (ii) turnkey drilling activities, and (iii) the increase in future cost associated with abandonment of wells.

Critical Accounting Policies

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 and other working interest owners. Royale operates most of its own wells and receives industry standard operator fees ("Supervisory Fees"). Supervisory Fees are recognized as a reduction to the Company's General and Administrative Expenses.

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.

The Company's Financial Statements include its *pro rata* ownership of wells. The Company usually sells a portion of the working interest in each well it drills or participates in to third-party participants and retains a portion of the prospect for its own account. 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.

Equity Method Investments

Investments in entities over which the Company has significant influence, but not control, are accounted for using the equity method of accounting. Income from equity method investments represents Royale's proportionate share of net income generated by the equity method. Equity method investments are included as noncurrent assets on the consolidated balance sheet.

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred. When a loss is deemed to have occurred and is other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in income.

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 2023 and 2022, impairment losses of $ 1,599,001 and $0, 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.

The Company sponsors turnkey drilling agreement arrangements in 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 to 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 their 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 participant 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, 2023 and 2022, Royale had deferred drilling obligations of $9,761,927 and $8,129,965 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 restricted cash 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, 2023, the Company has an accumulated deficit of $90,323,289, a working capital deficiency of $7,184,318 and a stockholders' deficit of $35,633,489. 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 do not possess funds necessary to implement our 2024 budget. Royale is continuing its drilling efforts with its direct working interest owners. In addition, 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, needed to fully fund our 2024 drilling budget and to support future operations.

Results of Operations for the Year Ended December 31, 2023, as Compared to the Year Ended December 31, 2022

For the year ended December 31, 2023, we had a net loss of $1,832,187 compared to the net loss of $145,594 during the year in 2022. Total revenues from operations in 2023 were $ 2,160,594, a decrease of $ 481,943 or 18.2%, from the total revenues of $2,642,537 in 2022, due to lower oil and natural gas commodity prices during 2023. Total expenses for operations in 2023 were $6,211,039, an increase of $1,112,761 or 21.8%, from total expenses of $5,098,278 in 2022, mainly due to higher lease impairments during 2023.

During the year ended 2023, revenues from oil and gas production decreased $497,196 or 19.0% to $ 2,114,026 from the 2022 revenues of $2,611,222. This decrease was mainly due to lower commodity prices realized for the sale of oil and gas in 2023. The net sales volume of oil and condensate for the year ended December 31, 2023 was approximately 22,399 barrels of oil with an average price of $74.27 versus approximately 18,015 barrels with an average price of $91.86 per barrel, in 2022. This represents an increase in net sales volume of approximately 4,384 barrels or 24.3%, which was due to wells completed and put online in 2023 and the latter half of 2022. The net sales volume of natural gas for the year ended December 31, 2023, was approximately 128,160 Mcf with an average price of $3.47 per Mcf, versus 135,136 Mcf with an average price of $7.01 per Mcf for the year in 2022. This represents a decrease in net sales volume of approximately 6,976 Mcf or 5.2%. The decrease in natural gas production volume was due to lower production volumes on existing wells due to natural declines.

Oil and natural gas lease operating expenses decreased by $196,851 or 10.2%, to $1,731,670 for the year ended December 31, 2023, from $1,928,521 for the year in 2022. This decrease was due to the receipt of water disposal recovery fees received in 2023 as we converted an existing non-producing oil well into a water injection well to reduce water disposal hauling costs paid to outside vendors. When measuring lease operating costs on a production or lifting cost basis, in 2023, the $1,731,670 equates to a $6.60 per Mcfe lifting cost versus a $7.93 per Mcfe lifting cost in 2022, due to the receipt of the water disposal fees and higher oil production volumes in 2023.

The aggregate of Supervisory Fees and Other Revenue was $46,568 for year ended December 31, 2023, an increase of $15,253 or 48.7% from $31,315 during the year in 2022. This increase was mainly due to higher interest income received in 2023 due to our higher cash balances.

Depreciation, depletion and amortization expense decreased to $346,866 from $575,909, a decrease of $229,043 or 39.8% for the year ended December 31, 2023, as compared to the year in 2022. The depletion rate is calculated using production by comparing capitalized cost to the recoverable reserves remaining. The decrease in depreciation expense was mainly due to a lower asset base due to impairments mainly on our California natural gas wells.

General and administrative expenses decreased by $83,182 or 4.6% from $1,808,197 for the year ended December 31, 2022, to $1,725,015 for the year in 2023. This decrease was due to lower employee related expenses due to cost reduction measures during 2023. Legal and accounting expense decreased to $435,372 for in 2023, compared to $526,550 in 2022, a $91,178 or 17.3% decrease. This decrease was primarily due to higher outside accounting fees in 2022, mainly related to conversion of our accounting software. Marketing expense for the year ended December 31, 2023, increased $91,324, or 35.3%, to $350,425, compared to $259,101 for the year in 2022. Marketing expense varies from period to period according to the number of marketing events attended by personnel and their associated costs.

At December 31, 2023, Royale had a Deferred Drilling Obligation of $9,761,927. During 2023, we removed $6,228,038 of drilling obligations as we completed one oil well in our Texas Jameson field and participated in drilling and completion of two successful oil wells in the Texas Permian basin and one dry well in southern California, while incurring expenses of $4,120,538, resulting in a gain of $2,107,500. At December 31, 2022, Royale had a Deferred Drilling Obligation of $8,129,965. During 2022, we removed $7,027,474 of drilling obligations as we completed five oil wells in Texas and participated in the drilling and completion of two wells in southern California, while incurring expenses of $5,301,060, resulting in a gain of $1,726,414.

During 2023, we recorded lease impairments of approximately $1.6 million on lease and land costs in our California natural gas fields where the carrying value exceeded the fair value. No lease impairments were recorded in 2022. During 2023, we recorded a gain on other of $54,975 as we reconciled employee related items previously recorded as liabilities. In 2023, we also recorded a gain on other of approximately $57,000 on our share of prior years property tax refunds received by RMX Resources, LLC. During 2023, we recorded a write down of $22,690 on certain well equipment that were either written down to their current market value or written off as they were no longer useable. During the year in 2022, we recorded a gain of $422,614 on settlement of accounts payable for a reduced amount. During 2022, we also recorded a gain on other of $163,571, mainly due to the receipt of Employee Retention Credit (ERC) payroll tax refunds from the Internal Revenue Service. During the year in 2022, we recorded a gain of $422,614 on settlement of accounts payable for a reduced amount.

Interest expense for the year ended December 31, 2023 and 2022, were $1,970 and $2,452 respectively.

In 2023 and 2022, 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 new federal rate of 21% plus the relevant state rates (mostly California, 8.8%).

Capital Resources and Liquidity

At December 31, 2023, Royale had current assets totaling $9,669,618 and current liabilities totaling $16,853,936, a $7,184,318 working capital deficit. We had cash and cash equivalents at December 31, 2023 of $2,202,521 and restricted cash of $3,325,000 compared to cash and cash equivalents of $1,650,507 and restricted cash of $2,249,627 at December 31, 2022.

Ordinarily, we fund our operations and cash needs from our available credit and cash flows generated from operations. We believe there is some doubt that the Company has the ability to meet liquidity demands through cash-flow from operations. In that event, the Company will seek alternative capital sources through additional sales of equity or debt securities, or the sale of property, which may not be available at all, or on terms we deem reasonable. We have plans to increase oil and gas revenue with commitments to participate in the drilling and completion of several non-operated wells in the Permian Basin in Texas.

At December 31, 2023, our other receivables net, which consists of joint interest billing receivables from direct working interest participants and industry partners, totaled $1,036,401, compared to $943,633 at December 31, 2022, a $92,768 increase. This increase was mainly due higher accounts receivables from direct working interest owners for lease operating expenses to increase production volumes mainly in our Texas Jameson field. At December 31, 2023, revenue receivable was $878,378, an increase of $176,441, compared to $701,937 at December 31, 2022, due to higher production volumes as two new non-operated wells came online at year end 2023. At December 31, 2023, our accounts payable and accrued expenses totaled $5,482,074, a decrease of $46,755 from the accounts payable at December 31, 2022 of $5,528,829, mainly due to payments on accounts payable at year end 2023.

We have not engaged in hedging activities nor do we use derivative instruments to manage market risks.

Operating Activities. For the years ended December 31, 2023 and 2022, cash used in operating activities totaled $769,919 and $2,809,788, respectively. This $2,039,869 decrease in cash used was primarily due to a decrease in prepaid drilling costs during the period in 2023 due to participating in the drilling of four non-operated Texas oil wells which were prepaid in 2022 and drilled and completed in 2023.

Investing Activities. Net cash provided by investing activities totaled $2,409,291 and $2,608,871 for the years ended December 31, 2023 and 2022, respectively. The difference was due to cash receipts of approximately $7.9 million in 2023 and $7.3 million in 2022 in direct working interest turnkey investments. During 2023, our turnkey drilling expenditures were approximately $5.5 million as we drilled and completed one oil well in our Texas Jameson field and participated in the drilling and completion of two Texas oil wells in the Permian basin and the drilling one California oil well. During 2022, our turnkey drilling expenditures were approximately $4.7 million as we drilled and completed five oil wells in Texas and participated in the drilling of two California oil wells.

Financing Activities. Net cash used in financing activities totaled $11,985 and $121,753 for the years ended December 31, 2023 and 2022, respectively. During 2023 we had financing lease payments of $11,985. During 2022, we had note payable and financing lease payments of $121,753.

Changes in Reserve Estimates

During 2023, our overall proved developed and undeveloped oil reserves decreased by 41.5% and our previously estimated proved developed and undeveloped oil reserve quantities were revised downward by approximately 185 thousand barrels. This downward revision was mainly the result of a decrease in proved undeveloped oil reserves from drilling locations which the Company had previously estimated. Our overall proved developed and undeveloped natural gas reserves decreased by 58.2% and our previously estimated proved developed and undeveloped natural gas reserve quantities were revised downward by approximately 720 thousand cubic feet of natural gas. This downward revision was mainly the result of a decrease in proved undeveloped natural gas reserves from drilling locations which the Company had previously estimated. See Note 15 – Supplemental Information About Oil and Gas Producing Activities (Unaudited), to our Financial Statements.

During 2022, our overall proved developed and undeveloped natural gas reserves decreased by 76.4% and our previously estimated proved developed and undeveloped natural gas reserve quantities were revised downward by approximately 1.3 million cubic feet of natural gas. This downward revision was mainly the result of a decrease in proved undeveloped oil reserves from drilling locations which the Company had previously estimated. See Note 15 – Supplemental Information About Oil and Gas Producing Activities (Unaudited)to our Financial Statements.

Item 7A Qualitative and Quantitative Disclosures About Market Risk

Not a required disclosure for smaller reporting companies.

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

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rules 13a-15(e) or 15d-15(e) under the Exchange Act. Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective to give reasonable assurance that information required to be publicly disclosed is recorded, processed, summarized and reported on a timely basis as of the end of the period covered by this annual report.

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over our financial reporting. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, management has conducted an assessment, including testing, using the criteria in Internal Control-Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Based on our evaluation under the framework in Internal Control-Integrated Framework, our Chief Executive Officer and Chief Financial Officer concluded that our internal control over financial reporting was not effective as of December 31, 2023 due to the material weakness that is described below.

Material Weakness and Remediation

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.

In connection with the audit of our 2019 consolidated financial statements, management identified a material weakness that existed because we did not maintain effective controls over our financial close and reporting process, and concluded that the financial close and reporting process needed additional formal procedures to ensure there are appropriate reviews over all financial reporting analysis. Management has also identified a material weakness that existed due to the lack of segregation of duties and controls, including user access, regarding our financial reporting system. Updated procedures have been implemented through the close process for the year ended December 31, 2023, but the material weakness on our financial close and reporting process was not alleviated. We will continue to monitor these throughout 2024 to be able to fully assess whether the procedures and controls are effective.

Attestation Report of the Independent Registered Public Accounting Firm.

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 registered public accounting firm pursuant to 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

Other than the remedial activities described above, no changes in our internal control over financial reporting occurred during the year ended December 31, 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART III

Item 10 Directors, Executive Officers and Corporate Governance

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, 2023:

Name	Age	First Became Director or Executive Officer	Positions Held
Chris Parada (1) (2)(3)(4)	53	2021	Chairman of the Board
Jonathan Gregory (1)(2)(3)(4)	59	2014	Vice-Chair of the Board of Directors
Johnny Jordan	63	2018	Chief Executive and Operating officer and Director
John Sullivan (1)(2)(3)(4)	65	2021	Director
Jeff Kerns (1) (2)(3)(4)	67	2021	Director
Stephen Hosmer	57	1995	Director

(1) Members of the Audit Committee
(2) Members of the compensation committee
(3) Members of the nominations committee
(4) Members identified as independent

The board has determined that directors John Sullivan, Chris Parada, Jonathan Gregory and Jeff Kerns qualify as independent directors.

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

Chris Parada – Chairman of the Board

Mr. Parada currently serves as Managing Director – Energy Finance for Cornerstone Capital Bank, a position he has held since January 2023. Cornerstone is a privately held financial institution with almost $2.0 billion in assets and over $325 million of regulatory capital. From April 2021 through December 2022, Mr. Parada was Vice President of Business Development for Finergy Capital/EnRes Resources, an alternative investment fund providing structured capital solutions to upstream oil and gas companies. For over 25 years Mr. Parada was an energy banker, most recently, as Managing Director - Head of Energy Finance for Legacy Texas Bank (2013-2019) where he started and built the Energy Finance team for Legacy Texas. While at Legacy Texas, Mr. Parada and the team successfully closed over $1.5 billion in transactions while he managed a team of seven professionals. Mr. Parada graduated in 1993 from Texas A&M University with a B.B.A. in Finance.

Jonathan Gregory – Vice-Chair of the Board of Directors

Mr. Gregory became a director of Royale in March 2014 and served as Royale's chief executive officer from September 10, 2015, until June 1, 2018. Prior to becoming Royale's CEO, Mr. Gregory, from March 2014 to July 2015, served as Chief Financial Officer and Chief Business Development Strategist for Americo Energy Resources, a private exploration and production company located in Houston, Texas. Prior to serving as CFO of Americo Energy, Mr. Gregory was CFO of J&S Oil & Gas, LLC, from April 2012 to February 2014. From December 2004 to April 2012, Mr. Gregory was head of the energy lending group in Houston, Texas for Texas Capital Bank, N.A. Mr. Gregory is presently CEO of RMX, a private Texas based oil and gas company with oil and gas properties primarily located in California, in which, Royale holds an equity interest. Mr. Gregory is also a Credit Advisor to Anvil Capital Partners, a private debt capital provider to upstream energy companies and serves on the advisory board of the Center for Compassionate Leadership. Mr. Gregory graduated from Lamar University in 1986 with a Bachelor's degree in Finance.

John Sullivan – Director

Mr. Sullivan first became a director and served as the Chairman of the Board from 2021 to 2023. Mr. Sullivan is the President of LTD Consulting Services LLC, which provides consulting and management services to private and public companies in the US and SE Asia, a position he has held since 2017. Previously, he held the position of Sr. Director at MMI International, a privately held, global supplier to the Data Storage, Aerospace and Oil and Gas industries from 2011-2017. In this role, he oversaw the sales and global operations for the Precision Forming Group, a division of MMI, with $250 million in annual sales.

Prior to this, as Director of Operations, COO and President, he spent eleven years, from 1999 until 2011, with Intri-Plex Technologies Inc., a leading design, engineering and manufacturing company to the Data Storage, Semi-conductor and Medical industries. In his various roles, he led the development and implementation of strategic sales and operating initiatives that resulted in significant top and bottom line growth. Overseeing the expansion of the business from a domestic manufacturing company to an international supplier of precision components with manufacturing facilities located in the US and SE Asia.

Previously, as COO and President of KR Precision Public Co. Ltd., a publicly held, global supplier of precision mechanical components, John was instrumental in transforming a small privately held company from a niche supplier to a publicly held industry leader listed on the SET 50.

John began his career in 1980 as an entrepreneur, spending ten years as a small business owner in the security and life safety industry. He grew his company organically and through acquisition, diversified its offerings and expanded its geographic footprint prior to it being acquired by ADT International in, a global leader in security and life safety industry, in 1990.

Johnny Jordan – Chief Executive Officer, President, Chief Operating Officer and Director

Mr. Jordan is a petroleum engineer with expertise in acquisitions, field economics and reserves analysis, bank negotiations, reservoir and field operations, and multi-team interaction. Mr. Jordan has been Royale Energy's Chief Executive Officer since 2019. Mr. Jordan served on the Board of Directors of Matrix and currently serves on the Board of Directors of both RMX Resources and CIPA. Mr. Jordan has been active in the oil and gas industry since 1980 beginning as a floor hand on a well service rig. He has held various staff and supervisory positions for Exxon, Mack Energy, Enron Oil and Gas and Venoco Corporation. He co-founded Matrix Oil Corporation in 1999 and served as its president until its merger with Royale in 2018. Mr. Jordan is a member of the Society of Petroleum Engineers, American Petroleum Institute and the Texas Independent Producers and Royalty Owners Association. Mr. Jordan has managed acquisition evaluations in many of the oil and gas producing basins in the US. Mr. Jordan received a B.S. in Chemical Engineering from the University of Oklahoma in 1983.

Jeff Kerns – Director

Mr. Kerns was a founding partner of Matrix Oil Corp in 1999, which merged with Royale Energy, Inc. nearly 20 years later in 2018. As a director and officer of Matrix, Mr. Kerns participated in growing the Company from zero production to owning and operating nearly 500 bbls of oil per day. Mr. Kerns was involved in all aspects of the Company's growth, but his primary focus was day to day operations.

Mr. Kerns has served as a consulting engineer to Royale Energy and Matrix Oil Company from 2018 to present.

Mr. Kerns started in the oil and gas business over 40 years ago as a roughneck in North Dakota working on rigs that drilled through the now famous Bakken Shale heading for deeper targets. Prior to Matrix Oil Corp, Mr. Kerns has held various staff and supervisory positions with Mobil Oil Corp (now ExxonMobil) and Venoco Inc, a small independent company headquartered in Santa Barbara, CA. He also gained broad skills working for many years as a consultant in the oil and gas business.

Mr. Kerns is a registered Professional Engineer in the state of CA. He received a BS degree from Stanford University in 1979. He served as an elected public official for 10 years on the local sanitary district board of directors as well as serving as a past president of a local Rotary International club and president of the San Joaquin Chapter of the American Petroleum Institute and has maintained a long term affiliation with SPE.

Stephen Hosmer – Director, Corporate Secretary

Mr. Hosmer first became a director in 1998, and served through 2018. He was then reappointed in January 2022, following his departure as the company's Chief Financial Officer, where he served since 1995. Mr. Hosmer also served as the company's Co-Chief Executive Officer from 2008 until September 2015.

During his tenure as CFO, Mr. Hosmer managed the development of over 178 wells, raised capital through a combination of debt and equity sources, and led the acquisition of more than 200 square miles of 3D seismic data. Mr. Hosmer holds a Bachelor of Science degree in Business Administration from Oral Roberts University in Tulsa, Oklahoma and an MBA degree from the President/Key Executive program at Pepperdine University.

Mr. Hosmer currently serves as the CFO for San Diego Rock Church, Managing Partner of Provident Ventures, and has also served on the board and/or consults for a number of not-for-profit organizations, including Venture Expeditions and Exile International, and Wycliffe Bible Translators.

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 charter, 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 Chris Parada qualifies as an "audit committee financial expert" as defined in Item 407(d)(5) of the Securities and Exchange Commission.

At the end of 2023, the members of the audit committee were John Sullivan (Chair), Jeff Kerns, Chris Parada and Jonathan Gregory.

In 2023 there were four meetings of the audit committee, at which all members participated.

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.

Delinquent Section 16(a) Reports

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. The following Form 4's for common stock issued to current and former board members were filed late or are in process of being filed, each of these filings consisted of two transactions that occurred in 2022, and two transactions that occurred in 2023:

Form 4 2022 Common Stock Issuance - Late Filings:			
Recipient	**Shares issued 2022**	**Shares issued 2023**	**Form 4 Filing Status**
Jonathan Gregory		903,529	In Process
John Sullivan	262,950	1,204,706	In Process
Chris Parada	262,950	1,204,706	In Process
Jeffrey Kerns	197,799	903,529	In Process
Stephen Hosmer	187,038	1,204,706	In Process
CIC RMX LP		3,266,055	In Process

Item 11 Executive Compensation

The following table summarizes the compensation of the chief executive officer, chief financial officer and the one other most highly compensated non-executive employee of Royale and its subsidiaries during the past three years.

SUMMARY COMPENSATION TABLE

	Year	Salary (3)	Bonus	Option Awards	All Other Compensation (1)	Total
Johnny Jordan (2)(3)(4)	2023	$ 255,769	$ -	$ -	$ 11,328	$ 267,097
(CEO)	2022	$ 255,769	$ -	$ -	$ 9,327	$ 265,096
Donald Hosmer	2023	$ 185,175	$ 84,475	$ -	$ 18,930	$ 288,580
(Business Development)	2022	$ 191,925	$ 102,975	$ -	$ 19,032	$ 313,932
Stephen Hosmer (5)	2023	$ -	$ -	$ -	$ 40,900	$ 40,900
(Former CFO)	2022	$ 67,210	$ -	$ -	$ 58,355	$ 125,656
Ronald Lipnick	2023	$ 194,654	$ 10,500	$ -	$ 5,840	$ 210,994
(CFO)	2022	$ 181,654	$ 15,000	$ -	$ 6,017	$ 202,671

(1) All other compensation consists of matching contributions to the Company's simple IRA plan, except for Donald H. Hosmer, who also received a $12,000 car allowance.
(2) Salary represents either direct payroll or common stock paid in lieu of taking a cash salary.
(3) Mr. Jordan became CEO of the Company in January 2019. Mr. Jordan joined the Company upon the merger with the Matrix entities on March 7, 2018.
(4) There was no compensation paid to Mr. Johnny Jordan for performance (Pay Versus Performance).
(5) Includes 6,000 shares owned by Stephen M. Hosmer's minor children.

In 2023, Johnny Jordan received a salary of $255,769. He did not receive any bonus or option awards. His additional compensation amounted to $11,328, resulting in a total compensation of $267,097. In 2022, his salary remained the same at $255,769. There were no bonuses or option awards, but he received additional compensation of $9,327, bringing his total compensation to $265,096.

For 2023, Donald Hosmer's salary was $185,175. He received a bonus of $84,475 but no option awards. His additional compensation was $18,930, resulting in a total compensation of $288,580. In 2022, his salary was $191,925, with a bonus of $102,975. Like 2023, there were no option awards, but his additional compensation amounted to $19,032, resulting in a total compensation of $313,932.

Ronald Lipnick's 2023 salary was $194,654. He received a bonus of $10,500 and no option awards. His additional compensation was $5,840, resulting in a total compensation of $210,994. In 2022, his salary was $181,654, with a bonus of $15,000. There were no option awards, but his additional compensation amounted to $6,017, resulting in a total compensation of $202,671.

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

No unvested stock awards were outstanding at the end of 2023.

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 annual report.

Members of the Compensation Committee:

Chris Parada, John Sullivan (Chair), and Jeff Kerns

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 yearend. The compensation committee makes recommendations to the board of directors annually on the compensation of the three top executives: Johnny Jordan, Chief Executive Officer, Donald H. Hosmer, Business Development, and Ronald Lipnick, Chief Financial Officer.

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 receives 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, from time-to-time, 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 and next most highly compensated non-executive officer 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 cash bonuses were paid to executive officers in 2023 or 2022, other than those listed for Donald Hosmer in the table above.

Pay Versus Performance

As required by Section 953(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 402(v) of Regulation S-K, we are providing the following information about the relationship between executive compensation actually paid ("CAP") and certain financial performance of our company.

Year (a)	Summary Compensation Table Total for Principal Executive Officer ("PEO") (b)	Compensation Actually Paid to PEO (c)	Average Summary Compensation Table Total for Non-PEO Named Executive Officers ("NEOs") (d)	Average Compensation Actually Paid to Non-PEO NEOs (e)	Value of Initial Fixed $100 Investment Based on Total Shareholder Return (f)	Net Income (loss) (h)
2023	$ 450,423	$ 518,991	$ 185,175	$ 288,580		$ (1,832,187)
2022	$ 504,633	$ 593,332	$ 191,925	$ 313,932		$ (145,594)
2021	$ 639,392	$ 670,371	$ 185,176	$ 235,706		$ (3,598,418)

Compensation of Directors

In 2023, 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 2023.

Name	Fees paid in Cash or Common Stock	Stock awards	Option awards	All Other Compensation	Total
John Sullivan	$ 52,000	$ -	$ -	$ -	$ 52,000
Chris Parada	$ 52,000	$ -	$ -	$ -	$ 52,000
Jeff Kerns	$ 39,000	$ -	$ -	$ -	$ 39,000
Stephen Hosmer	$ 52,000	$ -	$ -	$ -	$ 52,000
Jonathan Gregory	$ 39,000	$ -	$ -	$ -	$ 39,000
Former Board Members					
Thomas M. Gladney	$ 3,167	$ -	$ -	$ -	$ 3,167
Karen Kerns	$ 2,917	$ -	$ -	$ -	$ 2,917
Mel G. Riggs	$ 2,917	$ -	$ -	$ -	$ 2,917
Robert Vogel	$ 2,917	$ -	$ -	$ -	$ 2,917

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

Common Stock

At March 25, 2024, 71,863,829 shares of the registrant's Common Stock were outstanding.

The following table contains information regarding the ownership of Royale's Common Stock as March 25, 2023, by each director and executive officer of Royale, and 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 below possesses sole voting and investment power with respect to her or his shares. The holdings reported are based on reports filed with the Securities and Exchange Commission and the Company by the officers and directors.

Stockholder (1)	Number	Percent
Johnny Jordan (3)	28,425,174	40.28%
Jeff Kerns (5)	20,127,772	28.52%
Stephen M. Hosmer (2)	2,531,973	3.59%
John Sullivan	2,444,056	3.46%
Jonathan Gregory (4)	2,040,669	2.89%
Chris Parada	1,467,656	2.08%
All officers and directors as a group	57,271,240	81.16%

* Less than 1%.
(1) The mailing address of each listed stockholder is 1530 Hilton Head Rd, Suite 205, El Cajon, California 92021.
(2) Includes 6,000 shares owned by Stephen M. Hosmer's minor children.
(3) Includes 11,664,960 shares issuable upon conversion of Series B Convertible Preferred Stock.
(4) Includes 35,000 shares owned by Mr. Gregory's son.
(5) Includes 10,929,610 shares issuable upon conversion of Series B Convertible Preferred Stock.

There is no shareholder known by Royale to own beneficially more than 5% of the outstanding shares of each class of equity securities other than Messrs. Jordan and Kerns, as disclosed above.

Item 13 Certain Relationships and Related Transactions, and Director Independence

Our Chief Executive, Johnny Jordan, has accrued certain unpaid salaries, which were assumed by the Company. At December 31, 2023 Mr. Jordan was owed $46,926 in accrued unpaid guaranteed payments.

In 2018 the board of directors terminated the policy allowing employees and directors to participate, at cost, in wells drilled by the Company. Under the prior policy our former Chief Financial Officer and current board of director's secretary, Stephen Hosmer, had participated individually in 179 wells. At December 31, 2023, the Company had a receivable balance of $18,495 due from Stephen Hosmer and $7,654 from Donald Hosmer for normal drilling and lease operating expenses.

At December 31, 2023, we had a total payable of $23,087 due to RMX and its subsidiary, Matrix Oil Corporation, related to certain lease operating expenses for wells operated by RMX, and also had prepaid expenses of $382,520 primarily for future plugging and abandonment costs for wells operated by RMX. During 2023, RMX Resources LLC operated various oil wells we have interests in, from which we received revenues of approximately $374,000 and incurred lease operating costs of approximately $181,000. At December 31, 2023, we had a total payable of $164,669 owed to current and former board members for directors fees.

Royale had outstanding accrued unpaid guaranteed payments for unpaid salaries for periods predating their joining the Company due to certain former Matrix employees. At December 31, 2023, the balance due was $1,616,205. At December 31, 2023, Royale also had accrued unpaid liabilities of $1,306,605 due to certain former Matrix employees for periods predating their joining the Company.

The board has determined that directors John Sullivan, Chris Parada, Jonathan Gregory and Jeff Kerns qualify as independent directors.

Item 14 Principal Accountant Fees and Services

Horne LLP became our independent auditors effective March 31, 2023 for the year end December 31, 2022. The aggregate fees incurred for the years ended December 31, 2023 and 2022 are as follows:

	2023	2022
Audit fees (1)	$ 250,000	$ 282,120
Tax fees (2)	-	-
All other fees (3)	-	-
Total	$ 250,000	$ 282,120

(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 Company's audit committee 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. During 2023 all fees were pre-approved by the audit committee.

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 parties to the respective agreement, 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. None.

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

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
4.1	Royale Energy Holdings, Inc., Certificate of Designation of Series B 3.5% Redeemable Convertible Preferred Stock, filed with the Delaware Secretary of State on February 27, 2018, filed as Exhibit 2.5 to the Company's Form 8-A, filed March 8, 2018
10.11	Company Agreement of RMX (April 4, 2018), filed as Exhibit 10.1 to the Company's Form 8-K filed April 10, 2018
10.13	Conveyance of Term Overriding Royalty Interest between Sunny Frog Oil, LLC, and Royale (April 4, 2018), filed as Exhibit 10.3 to the Company's Form 8-K filed April 10, 2018
10.17	Royale Energy, Inc., 2018 Equity Incentive Plan, filed as Exhibit 99.1 to the Company's Form S-8 filed October 29, 2018
10.25	Employment Agreement between the Company and Michael McCaskey, filed as Exhibit 10.9 to the Company's Form S-8 filed October 29, 2018
10.26	Employment Agreement between the Company and Jeffrey Kerns, filed as Exhibit 10.10 to the Company's Form S-8 filed October 29, 2018
10.27	Incentive Stock Option Agreement between the Company and Stephen M. Hosmer, filed as Exhibit 10.11 to the Company's Form S-8 filed October 29, 2018
16.1	Letter of Weaver & Tidwell L.L.P. to the Securities and Exchange Commission dated December 7, 2022, files as Exhibit 16.1 to the Company's Form 8-K filed December 7, 2022
21.1*	Subsidiaries of Registrant
23.1*	Consent of Horne LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Rule 13a-14(a), 115d-14(a) Certification
31.2*	Rule 13a-14(a), 115d-14(a) Certification
32.1*	Section 1350 Certification
32.2*	Section 1350 Certification
99.1*	Report of Netherland, Sewell & Associates, Inc.
101.INS	Inline XBRL Instance Document
101.SCH	Inline XBRL Taxonomy Extension Schema
101.CAL	Inline XBRL Taxonomy Extension Calculation Linkbase
101.DEF	Inline XBRL Taxonomy Extension Definition Linkbase
101.LAB	Inline XBRL Taxonomy Extension Label Linkbase
101.PRE	Inline XBRL Taxonomy Extension Presentation Linkbase
104	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)

* Filed herewith

SIGNATURES

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

	Royale Energy, Inc.
Date: April 12, 2024	*/s/ Johnny Jordan* Johnny Jordan Chief Executive Officer
Date: April 12, 2024	*/s/ Ronald Lipnick* Ronald Lipnick Chief Financial 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: April 12, 2024	*/s/ Chris Parada* Chris Parada Chairman of the Board of Directors
Date: April 12, 2024	*/s/ Jonathan Gregory* Jonathan Gregory Vice-Chair of the Board of Directors
Date: April 12, 2024	*/s/ John Sullivan* John Sullivan Director
Date: April 12, 2024	*/s/ Jeff Kerns* Jeff Kerns Director
Date: April 12, 2024	*/s/ Stephen Hosmer* Stephen Hosmer Director

ROYALE ENERGY, INC.
INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Royale Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Royale Energy, Inc. and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, stockholders' deficit and cash flows for the years then ended, and the related notes to the consolidated 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, 2023 and 2022, 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 Uncertainty

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 and its total liabilities exceed its total assets. 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.

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.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Estimation of Proved Reserves of Oil and Gas Properties

Critical Accounting Matter Description

As described in Note 1 to the financial statements, the Company accounts for its oil and gas properties using the successful efforts method of accounting which requires management to make estimates of proved reserve volumes and future revenues and expenses to calculate depletion expense and measure its oil and gas properties for potential impairment. To estimate the volume of proved reserves and future revenues, management makes significant estimates and assumptions, including forecasting the production decline rate of producing properties and the timing and volume of production associated with the Company's development plan for proved undeveloped properties. In addition, the estimation of proved reserves is also impacted by management's judgments and estimates regarding the financial performance of wells associated with proved reserves to determine if wells are expected, with reasonable certainty, to be economical under the appropriate pricing assumptions required in the estimation of depletion expense and potential impairment measurements. We identified the estimation of proved reserves of oil and gas properties, due to its impact on depletion expense and impairment evaluation, as a critical audit matter.

The principal consideration for our determination that the estimation of proved reserves is a critical audit matter is that changes in certain inputs and assumptions necessary to estimate the volumes and future net revenues of the Company’s proved reserves require a high degree of subjectivity and could have a significant impact on the measurement of depletion expense or the impairment assessment. In turn, auditing those inputs and assumptions required subjective and complex auditor judgement.

How the Critical Audit Matter was Addressed in the Audit

We obtained an understanding of the design and implementation of management's controls related to the estimation of proved reserves by evaluating the level of knowledge, skill, and ability of the Company's reservoir engineering specialists and their relationship to the Company, made inquiries of those reservoir engineers regarding the process followed and judgments made to estimate the Company's proved reserve volumes, and reviewed the reserve report prepared by the Company's specialists.

To the extent key, sensitive inputs and assumptions used to determine proved reserve volumes and other cash flow inputs and assumptions are derived from the Company's accounting records, such as commodity pricing, historical pricing differentials, operating costs, estimated capital costs and working and net revenue interests, we evaluated management's process for determining the assumptions, including examining the underlying support, on a sample basis. These audit procedures, among others included the following:

- Compared the estimated pricing differentials used in the reserve report to realized prices related to revenue transactions recorded in the current year and examined contractual support for the pricing differentials;

- Evaluated the models used to estimate the operating costs at year-end compared to historical operating costs;

- Compared the models used to determine the future capital expenditures and compared estimated future capital expenditures used in the reserve report to amounts expended for recently drilled and completed wells with similar locations;

- Evaluated the working and net revenue interests used in the reserve report by inspecting a sample of ownership interest, historical pricing differentials and operating costs to underlying support from the Company's accounting records;

- Evaluated the Company's evidence supporting the amount of proved undeveloped properties reflected in the reserve report by examining support for the Company's or the operator's ability and intent to develop the proved undeveloped properties; and

- Applied analytical procedures to the reserve report by comparing to historical actual results and to the prior year reserve report.

Deferred Drilling Obligation and Gain on Turnkey Drilling

Critical Accounting Matter Description

As described in Note 1 to the financial statements, the Company sponsors turnkey drilling arrangements in proved and unproved properties as a pooling of assets in a joint undertaking, whereby proceeds from participants are reported as deferred drilling obligations. That obligation is reduced as costs to complete are incurred, with any excess costs booked as an increase to the Company's property account. Gain on turnkey drilling represents funds received from turnkey drilling participants in excess of all costs the Company incurs during the drilling programs and is recognized only upon making the determination that the Company's obligations have been fulfilled in accordance with the turnkey drilling agreement. The Company's deferred drilling obligation was approximately $9.8 million as of December 31, 2023, and the gain on turnkey drilling was approximately $2.1 million for the year ended December 31, 2023.

Company management applies significant estimation in determining the expected cost to drill a well and to develop the well site, and significant judgment in determining when they have fulfilled their obligations under the turnkey drilling agreement triggering the recognition of turnkey gain. Both factors may impact the amount and timing of the recognition of a turnkey gain and involve a high degree of auditor judgement related to the matter. These factors were the principal considerations that led us to determine that the deferred drilling obligation and the related gain on turnkey drilling arrangements is a critical audit matter.

How the Critical Audit Matter was Addressed in the Audit

We obtained an understanding of the design and implementation of management's controls related to the estimations in determining the expected cost to drill a well, develop the well site, and when obligations under the turnkey drilling agreements have been fulfilled. Other audit procedures involved selecting a sample of wells to test management's estimates as follows:

- Obtained the master worksheet for each selected well, recalculated the worksheet for clerical accuracy and selected a sample of direct working interest ("DWI") investors;

- Obtained the signed field subscription agreement for each selected investor in each well, verified the investment ownership amount per the signed field subscription agreement agreed to the amount invested and the number of units within the master worksheet, vouched the cash received from the DWI investors and agreed the significant terms to the related turnkey drilling agreement;

- Obtained a schedule of costs incurred to drill the selected well, recalculated the schedule for clerical accuracy and obtained support from management to substantiate the costs incurred; and

- Obtained evidence substantiating the timing and amount of the turnkey gain pertaining to a sample of wells drilled and assessed that the recognized turnkey gain was appropriate as defined under the terms of the related turnkey drilling agreement.

/s/ HORNE LLP

We have served as the Company's auditor since 2023.

Ridgeland, Mississippi
April 12, 2024

ROYALE ENERGY, INC.
CONSOLIDATED BALANCE SHEETS
DECEMBER 31,

		2023		2022
ASSETS				
Current Assets:				
Cash and Cash Equivalents	$	2,202,521	$	1,650,507
Restricted Cash		3,325,000		2,249,627
Other Receivables, net		1,036,401		943,633
Revenue Receivables		878,378		701,937
Prepaid Expenses and Other Current Assets		558,169		1,935,346
Deferred Drilling Costs		1,669,149		1,219,177
Prepaid Drilling to RMX Resources, LLC		-		114,563
Total Current Assets		9,669,618		8,814,790
Other Assets		589,865		589,865
Right of Use Asset - Operating Leases		254,008		335,213
Oil and Gas Properties (Successful Efforts Basis), Real Property and Equipment and Fixtures, net		2,401,902		2,040,320
Total Assets	$	12,915,393	$	11,780,188

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

ROYALE ENERGY, INC.
CONSOLIDATED BALANCE SHEETS (Continued)
DECEMBER 31,

	2023	2022
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current Liabilities:		
Accounts Payable and Accrued Expenses	$ 5,482,074	$ 5,528,829
Royalties Payable	612,925	612,925
Due RMX Resources, LLC	23,087	23,087
Accrued Liabilities	215,693	208,307
Operating Leases - Current	83,230	81,995
Asset Retirement Obligation - Current	675,000	675,000
Deferred Drilling Obligations	9,761,927	8,129,965
Total Current Liabilities	16,853,936	15,260,108
Noncurrent Liabilities:		
Asset Retirement Obligation	4,151,847	2,867,479
Operating Leases - Non-current	171,439	254,858
Accrued Unpaid Guaranteed Payments	1,616,205	1,616,205
Accrued Liabilities - Non-current	1,306,605	1,306,605
Total Liabilities	24,100,032	21,305,255
Mezzanine Equity:		
Convertible Preferred Stock, Series B, $10 par value, 3,000,000 Shares Authorized, 2,444,885 and 2,361,154 shares issued and outstanding at December 31, 2023 and 2022, respectively	24,448,850	23,611,536
Stockholders' Deficit:		
Common Stock, .001 Par Value, 280,000,000 Shares Authorized 70,564,188 and 61,876,957 shares issued and outstanding at December 31, 2023 and 2022, respectively	70,564	61,876
Additional Paid in Capital	54,619,236	54,447,923
Accumulated Deficit	(90,323,289)	(87,646,402)
Total Stockholders' Deficit	(35,633,489)	(33,136,603)
Total Liabilities, Mezzanine Equity and Stockholders' Deficit	$ 12,915,393	$ 11,780,188

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

ROYALE ENERGY, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

	2023	2022
Revenues:		
Sale of Oil and Gas	$ 2,114,026	$ 2,611,222
Supervisory Fees and Other	46,568	31,315
Total Revenues	2,160,594	2,642,537
Costs and Expenses:		
Lease Operating	1,731,670	1,928,521
Impairment	1,599,001	-
Depreciation, Depletion and Amortization	346,866	575,909
Well Equipment Write down	22,690	-
General and Administrative	1,725,015	1,808,197
Legal and Accounting	435,372	526,550
Marketing	350,425	259,101
Total Costs and Expenses	6,211,039	5,098,278
Gain on Turnkey Drilling Programs	2,107,500	1,726,414
Loss from Operations	(1,942,945)	(729,327)
Other Income (Expense):		
Interest Expense	(1,970)	(2,452)
Gain on Settlement of Payables	-	422,614
Other Gain	112,728	163,571
Loss Before Income Tax Expense	(1,832,187)	(145,594)
Net Loss	$ (1,832,187)	$ (145,594)
Basic and Diluted Loss Per Share	$ (0.04)	$ (0.02)
Weighted average number of common shares outstanding, basic and diluted	65,758,185	58,472,340

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

ROYALE ENERGY, INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' DEFICIT
FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

	Common Stock				
	Number Shares Issued and Outstanding	Amount	Additional Paid in Capital	Accumulated Deficit	Total Stockholders' Deficit
Balance, December 31, 2021	**56,239,715**	**$ 56,239**	**$ 54,058,554**	**$ (86,685,036)**	**$ (32,570,243)**
Stock issued in lieu of Cash Compensation	5,637,242	5,637	389,369	-	395,006
Preferred Series B 3.5% Dividend	-	-	-	(815,772)	(815,772)
Net Loss	-	-	-	(145,594)	(145,594)
Balance, December 31, 2022	**61,876,957**	**61,876**	**54,447,923**	**(87,646,402)**	**(33,136,603)**
Cashless Warrant Exercise Issuance	3,266,055	3,266	(3,266)	-	-
Stock issued in lieu of Cash Compensation	5,421,176	5,422	174,579	-	180,001
Preferred Series B 3.5% Dividend	-	-	-	(844,700)	(844,700)
Net Loss	-	-	-	(1,832,187)	(1,832,187)
Balance, December 31, 2023	**70,564,188**	**$ 70,564**	**$ 54,619,236**	**$ (90,323,289)**	**$ (35,633,489)**

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

ROYALE ENERGY, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2023 AND 2022

	2023	2022
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net Loss	$ (1,832,187)	$ (145,594)
Adjustments to Reconcile Net Loss to Net Cash Used by Operating Activities:		
Depreciation, Depletion, and Amortization	346,866	575,909
Impairment	1,599,001	-
(Gain) Loss on Turnkey Drilling Programs	(2,107,500)	(1,726,414)
Gain on Settlement of Accounts Payable	-	(422,614)
Other Gain	(112,728)	(163,571)
Well Equipment Write Down	22,690	-
Stock-Based Compensation	180,001	395,006
Right of Use Asset Depreciation	11,006	10,989
(Increase) Decrease in:		
Other & Revenue Receivables	(269,209)	(867,287)
Prepaid Expenses and Other Assets	1,491,740	(1,613,641)
Increase (Decrease) in:		
Accounts Payable and Accrued Expenses	(99,599)	1,157,909
Royalties Payable	-	(10,480)
Net Cash Used in Operating Activities	(769,919)	(2,809,788)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Expenditures for Oil and Gas Properties	(5,450,709)	(4,723,629)
Proceeds from Turnkey Drilling Programs	7,860,000	7,332,500
Net Cash Provided by Investing Activities	2,409,291	2,608,871
CASH FLOWS FROM FINANCING ACTIVITIES:		
Principal Payments on Long-Term Debt	(11,985)	(121,753)
Net Used in Financing Activities	(11,985)	(121,753)
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	1,627,387	(322,670)
Cash, Cash Equivalents, and Restricted Cash at Beginning of Year	3,900,134	4,222,804
Cash, Cash Equivalents, and Restricted Cash at End of Year	$ 5,527,521	$ 3,900,134
Cash Paid for Interest	$ 1,970	$ 2,452
Cash Paid for Taxes	$ 10,427	$ 6,850
Supplemental Schedule of Non-Cash Investing and Financing Transactions:		
Asset Retirement Obligation Addition	$ 37,260	$ 29,338
Increase (Decrease) in Capital Accrued Balance	$ 165,572	$ (206,806)
Series B Paid-In-Kind Dividends	$ 844,700	$ 815,772

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

ROYALE ENERGY, INC.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This summary of significant accounting policies of Royale Energy, Inc. (in these notes sometimes called “we”, “us”, “our”) is presented to assist in understanding our financial statements.

These consolidated financial statements include the accounts of Royale Energy, Inc and our controlled subsidiaries. Investments in unincorporated joint ventures and undivided interests in certain operating assets are consolidated on a pro rata basis. The consolidated statements and notes are representations of our 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 consolidated financial statements.

Description of Business

We are an independent oil and gas producer and we also perform turnkey drilling operations. We own wells and leases in major geological basins located primarily in California, Texas, and Oklahoma, and offer fractional working interests and seek 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 consolidated 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.

Estimated quantities of crude oil and condensate, NGLs and natural gas reserves is a significant estimate that requires judgment. All of the reserve data included in this Form 10-K are estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil and condensate, NGLs and natural gas. There are numerous uncertainties inherent in estimating quantities of proved crude oil and condensate, NGLs and natural gas reserves. The accuracy of any reserves estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil and condensate, NGLs and natural gas that are ultimately recovered. See Note 15 – Supplemental Information About Oil and Gas Producing Activities (Unaudited) to our Consolidated Financial Statements for further detail.

Other items subject to estimates and assumptions include the carrying amounts of accounts receivable, property, plant and equipment, equity method investments, asset retirement obligations, and valuation allowances for deferred tax assets, among others. Although we believe these estimates are accurate, actual results could differ from these estimates.

Liquidity and Going Concern

The primary sources of liquidity have historically been issuances of common stock, oil and gas sales through ongoing operations and the sale of oil and gas properties. There are factors that give rise to substantial doubt about our ability to meet liquidity demands, and we anticipate that our primary sources of liquidity will be from the issuance of debt and/or equity, the sale of oil and natural gas property participation interests through our normal course of business and the sale of non-strategic assets.

Our 2023 consolidated financial statements reflect a working capital deficiency of $7,184,318, an accumulated deficit of $90,323,289 and a net loss of $1,832,187. 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 we are unable to continue as a going concern.

Management plans to alleviate the going concern by implementing cost control measures that include the reduction of overhead costs and through the sale of non-strategic assets, and if necessary seek additional debt and/or equity financing. 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 us and whether we will become profitable and generate positive operating cash flow. If we are unable to raise sufficient additional funds, we will have to develop and implement a plan to further extend payables 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.

Restricted Cash

We sponsor turnkey drilling arrangements in proved and unproved properties. The contracts require that participants pay us the full contract price upon execution of the drilling agreement. Each participant earns an undivided interest in the well bore at the completion of the well. A portion of the funds received in advance of the drilling of a well from a working interest participant are held for the expressed purpose of drilling a well. If something changes, we may designate these funds for a substitute well. Under certain conditions, a portion of these funds may be required to be returned to a participant. Once the well is drilled, the funds are used to satisfy the drilling cost. We classify these funds prior to commencement of drilling as restricted cash based on guidance codified as under the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 230-10-50-8. In the event that progress payments are made from these funds; they are recorded as Prepaid Expenses and Other Current Assets.

The following table provides a reconciliation of cash, cash equivalents, and restricted cash reported within the consolidated balance sheets that sum to the total of the same amounts shown in the statement of cash flows.

	Year Ended December 31,	
	2023	2022
Cash and cash equivalents	$ 2,202,521	$ 1,650,507
Restricted cash	3,325,000	2,249,627
Total cash, cash equivalents, and restricted cash shown in the statement of cash flows	$ 5,527,521	$ 3,900,134

Other Receivables

Our other receivables consist of receivables from direct working interest investors and industry partners. We provide for uncollectible accounts receivable using the allowance method of accounting for credit risk. 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 fully 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, 2023 and 2022, we maintained an allowance for uncollectable accounts of $1,837,551 and $2,757,549, respectively, for receivables from direct working interest investors whose expenses on non-producing wells exceed expected collectable amounts.

Revenue Receivables

Our revenue receivables consist 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. Historically, we have not had no historical losses related to the collection of revenue receivables, and as such have determined that an allowance for revenue receivables is not currently necessary.

Equity Method Investments

Investments in entities over which we have significant influence, but not control, are accounted for using the equity method of accounting. Income from equity method investments represents our proportionate share of net income generated by the equity method investees and is reflected in revenue and other income in our consolidated statements of income. Equity method investments are included as noncurrent assets on the consolidated balance sheets.

Equity method investments are assessed for impairment whenever changes in the facts and circumstances indicate a loss in value may have occurred as called for under ASC 323, Investments—Equity Method and Joint Ventures. When a loss is deemed to have occurred and is other than temporary, the carrying value of the equity method investment is written down to fair value, and the amount of the write-down is included in the consolidated statement of operations income.

Revenue Recognition

A significant portion of our revenues are derived from the sale of crude oil, condensate, natural gas liquids ("NGLs") and natural gas under spot and term agreements with our customers as follows:

	Year Ended December 31, 2023	2022
Oil & Condensate Sales	$ 1,663,546	$ 1,654,840
Natural Gas Sales	445,111	947,407
NGL Sales	5,369	8,975
	$ 2,114,026	$ 2,611,222

The pricing in our hydrocarbon sales agreements are determined using various published benchmarks which are adjusted for negotiated quality and location differentials. As a result, revenue collected under our agreements with customers is highly dependent on the market conditions and may fluctuate considerably as the hydrocarbon market prices rise or fall. Typically, our customers pay us monthly, within a short period of time after we deliver the hydrocarbon products. As such, we do not have any financing element associated with our contracts. We do not have any issues related to returns or refunds, as product specifications are standardized for the industry and are typically measured when transferred to a common carrier or midstream entity, and other contractual mechanisms (e.g., price adjustments) are used when products do not meet those specifications.

In limited cases, we may also collect advance payments from customers as stipulated in our agreements; payments in excess of recognized revenue are recorded as contract liabilities on our consolidated balance sheets.

Under our hydrocarbon sales agreements, the entire consideration amount is variable either due to pricing and/or volumes. We recognize revenues in the amount of variable consideration allocated to distinct units of hydrocarbons transferred to a customer. Such allocation reflects the amount of total consideration we expect to collect for completed deliveries of hydrocarbons and the terms of variable payment relate specifically to our efforts to satisfy the performance obligations under these contracts. Our performance obligations under our hydrocarbon sales agreements are to deliver either the entire production from the dedicated wells or specified contractual volumes of hydrocarbons.

We often serve as the operator for jointly owned oil and gas properties. As part of this role, we perform activities to explore, develop and produce oil and gas properties in accordance with the joint operating arrangement and collective decisions of the joint parties. Other working interest owners reimburse us for costs incurred based on our agreements. We determined that these activities are not performed as part of customer relationships, and such reimbursements are recorded as cost reimbursements.

We commonly market the share of production belonging to other working interest owners as the operator of jointly owned oil and gas properties. Those marketing activities are carried out as part of the collaborative arrangement, and we do not purchase or otherwise obtain control of other working interest owners' share of production. Therefore, we act as a principal only in regard to the sale of our share of production and recognize revenue for the volumes associated with our net production.

We frequently sell a portion of the working interest in each well we drill or participate in to third-party investors and retain a portion of the prospect for our own account. We typically guarantee a cost to drill to the third-party drilling participants and record a loss or gain on the difference between the guaranteed price and the actual cost to drill the well. When monies are received from third parties for future drilling obligations, we record the liability as Turnkey Drilling Obligations. Once the contracted depth for the drilling of the well is reached and a determination as to the commercial viability of the well (typically called "Casing Point Election" or "Logging Point"), the difference in the actual cost to drill and the guaranteed cost is recorded as income or expense depending on whether there was a gain or loss.

Crude oil and condensate

For the crude sales agreements, we satisfy our performance obligations and recognize revenue once customers take control of the crude at the designated delivery points, which include pipelines, trucks or vessels.

Natural Gas and NGLs

When selling natural gas and NGLs, we engage midstream entities to process our production stream by separating natural gas from the NGLs. Frequently, these midstream entities also purchase our natural gas and NGLs under the same agreements. In these situations, we determined the performance obligation is complete and satisfied at the tailgate of the processing plant when the natural gas and NGLs become identifiable and measurable products. We determined the plant tailgate is the point in time where control, is transferred to midstream entities and they are entitled to significant risks and rewards of ownership of the natural gas and NGLs.

The amounts due to midstream entities for gathering and processing services are recognized as shipping and handling cost and included as lease operating expense in our consolidated Statement of Operations, since we make those payments in exchange for distinct services with the exception of natural gas sold to PG&E where transportation cost is netted directly against revenues. Under some of our natural gas processing agreements, we have an option to take the processed natural gas and NGLs in-kind and sell to customers other than the processing company. In those circumstances, our performance obligations are complete after delivering the processed hydrocarbons to the customer at the designated delivery points, which may be the tailgate of the processing plant or an alternative delivery point requested by the customer.

Turnkey Drilling Obligations

We manage these Turnkey Agreements for the participants of the well. The collections of pre-drilling Authorization for Expenditure (“AFE”) amounts are segregated and the gains and losses on the Turnkey Agreements are recorded in income or expense at the time of the casing point election in accordance with ASC 932. We manage the performance obligation for the well participants and only record revenue or expense at the time the performance obligation of the Turnkey Agreement has been satisfied.

Supervisory Fees and Other

For the years ended December 31, 2023 and 2022, we recognized $46,568 and $31,315, mainly from interest income and subleasing a portion of unused office space. .

Oil and Gas Property and Equipment

Successful Efforts

We use the “successful efforts” method to account for our exploration and production activities. Under this method, we accumulate our proportionate share of costs on a well-by-well basis with certain exploratory expenditures and exploratory dry holes being expensed as incurred, and capitalize expenditures for productive wells. We amortize the costs of productive wells under the unit-of-production method.

We carry, 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 we are 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 Cost

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 our 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.

Depreciation, Depletion and Amortization

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 drilling phase commences with the development of the detailed engineering design and ends when the 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.

Impairment

We evaluate our oil and gas producing properties, including capitalized costs of exploratory wells and development costs, for impairment of value whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the expected undiscounted future cash flows from the use of the asset and its eventual disposition is less than the carrying amount of the asset, an impairment loss is recognized based on the fair value of the asset. Oil and gas producing properties are reviewed for impairment on a field-by-field basis or, in certain instances, by logical grouping of assets if there is significant shared infrastructure or contractual terms that cause economic interdependency amongst separate, discrete fields. Oil and gas producing properties deemed to be impaired are written down to their fair value, as determined by discounted future net cash flows or, if available, comparable market value. We evaluate our unproved property investment and record impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, this amount is reported in exploration expenses in our consolidated statements of operations. During 2023 we recorded impairment losses of $1,599,001, on various capitalized lease and land costs where the carrying value exceeded the fair value. Of this amount $1,292,502 was impaired as a result of increased abandonment cost estimates and increases working interest in those costs. In 2022 there were no impairment losses.

Upon the sale or retirement of a complete field of a proved property, we eliminate the cost from our books, and the resultant gain or loss is recorded to our consolidated statements 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 our consolidated statements 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 our turnkey drilling agreements include unproved property, total drilling costs incurred to satisfy our 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.

Long-Lived Assets Classified as Held for Sale

We classify long-lived assets as Held-for-Sale when the criteria of ASC 360-10-45-9 through 45-11, Impairment and Disposal of Long-Lived Assets, have been met. This criterion is listed below:

- Management has committed to a plan to sell the asset;
- The asset group is available for immediate sale in its present condition;
- An active program is underway to locate potential buyers;
- The sale is probable within one year;
- The asset group is being marketed at a price that is reasonable relative to its current fair value; and
- Actions required to complete the plan indicate that it is unlikely that significant changes to the plan will be made or the plan will be withdrawn.

Assets held for sale are carried at the lower of cost or fair market value less cost of disposal in current assets. If we retain the responsibility for the P&A, equipment removal or site restoration, the associated anticipated expense is carried as current an asset retirement obligation (“ARO”) (See Note 3, below).

Turnkey Drilling

We sponsor turnkey drilling agreement arrangements in proved and 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 our obligations and are incurred with any excess booked against our property account to reduce any basis in our own interest. Gains on Turnkey Drilling Programs represent funds received from turnkey drilling participants in excess of all costs we incur during the drilling programs (e.g., lease acquisition, exploration and development costs), including costs incurred on behalf of participants and costs incurred for our own account; and are recognized only upon making this determination after our obligations have been fulfilled.

The contracts require the participants pay us the full contract price upon execution of the agreement. We complete 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 their proportionate share of operating costs. We retain 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. We hold 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, 2023 and 2022, we had Deferred Drilling Obligations of $9,761,927 and $8,129,965, respectively. During 2023, we disposed of $6,228,038 of drilling obligations as we completed one oil well in our Texas Jameson field and participated in drilling and completion of two successful oil wells in the Texas Permian basin and one dry well in southern California, while incurring expenses of $4,120,538, resulting in a gain of $2,107,500. During 2022, we disposed of $7,027,474 of drilling obligations as we completed five oil wells in Texas and participated in the drilling and completion of two wells in southern California, while incurring expenses of $5,301,060, resulting in a gain of $1,726,414.

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

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.

Loss Per Share

Basic and diluted losses per share are calculated as follows:

	Year Ended December 31,			
	2023		**2022**	
	Basic	**Diluted**	**Basic**	**Diluted**
Net Loss	$ (1,832,187)	$ (1,832,187)	$ (145,594)	$ (145,594)
Less: Preferred Stock Dividend	844,700	844,700	815,772	815,772
Less: Preferred Stock Dividend in Arrears	-	-	-	-
Net Loss Attributable to Common Shareholders	(2,676,887)	(2,676,887)	(961,366)	(961,366)
Weighted average common shares outstanding	65,758,185	65,758,185	58,472,340	58,472,340
Effect of dilutive securities	-	-	-	-
Weighted average common shares, including Dilutive effect	65,758,185	65,758,185	58,472,340	58,472,340
Per share:				
Net Loss	$ (0.04)	$ (0.04)	$ (0.02)	$ (0.02)

For the years ended December 31, 2023 and 2022, Royale Energy had dilutive securities of 24,448,850 and 27,058,677 respectively. These securities were not included in the dilutive loss per share due to their antidilutive nature.

Stock Based Compensation

We have adopted ASC 718, Compensation – Stock Compensation, for share-based payments. This topic requires that the cost resulting from all share-based payment transactions be recognized in the financial statements. It further establishes fair value as the measurement objective in accounting for share-based payment arrangements and requires all entities to apply a fair-value based measurement method in accounting for share-based payment transactions with employees except for equity instruments held by employee stock ownership plans.

Income Taxes

We utilize 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 ASC 740. 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 guidance as provided by ASC 820 and 825, assets and liabilities that are measured at fair value on a recurring and nonrecurring basis in periods subsequent to initial recognition, the reporting entity shall disclose information that enable users of our 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, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs to the extent possible as well as consider counterparty credit risk in our assessment of fair value. Carrying amounts of our 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, 2023 and 2022, we do not have any financial assets measured and recognized at fair value on a recurring basis. We estimate asset retirement obligations pursuant to the provisions of ASC 410, Asset Retirement and Environmental Obligations. 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 2 – Oil and Gas Properties, Equipment and Fixtures for further discussion of our asset retirement obligations.

Accounts Payable and Accrued Expenses

At December 31, 2023 and 2022, the components of accounts payable and accrued expenses consisted of:

	2023	2022
Trade Payables including accruals	$ 2,736,661	$ 3,108,931
Direct working interest investors related accruals	1,978,542	1,801,818
Current drilling efforts accrued expenses	188,482	22,910
Accrued Liabilities	400,296	400,296
Employee related accruals	170,312	189,736
Deferred rent	7,781	5,138
	$ 5,482,074	$ 5,528,829

Accrued – Non-current

At December 31, 2023 and 2022, we had non-current accrued liabilities of $1,306,605 and accrued unpaid guaranteed payment of $1,616,205, due to certain Matrix Oil Corp (“Matrix”) principals, from periods prior to the merger with the Matrix entities during March of 2018. These obligations are a result of the merger with Matrix in 2018, and are not expected to be paid in 2024.

Business Combinations

From time-to-time, we acquire businesses in the oil and gas industry. We primarily target businesses in geological basins that we consider to be in a focus area. Businesses are included in the consolidated financial statements from the date of acquisition.

We recognize, separately from goodwill, the identifiable assets acquired and liabilities assumed at their estimated acquisition-date fair values. We measure and recognize goodwill as of the acquisition date as the excess of: (1) the aggregate of the fair value of consideration transferred, the fair value of any noncontrolling interest in the acquiree (if any) and the acquisition date fair value of our previously held equity interest in the acquiree (if any), over (2) the fair value of assets acquired and liabilities assumed. If information about facts and circumstances existing as of the acquisition date is incomplete by the end of the reporting period in which a business combination occurs, we report provisional amounts for the items for which the accounting is incomplete. The measurement or allocation period ends once we receive the information we are seeking; however, this period will generally not exceed one year from the acquisition date. Any material adjustments recognized during the measurement period will be reflected retrospectively in the consolidated financial statements of the subsequent period. We recognize third-party transaction-related costs as expense currently in the period in which they are incurred.

Changes in Accounting Standards

Recently Adopted

ASU 2016-13, Credit Impairment

In June of 2016, the FASB issued ASC Topic 326, Financial Instruments – Credit Losses. This new guidance replaces the current incurred loss impairment model with a requirement to recognize lifetime expected credit losses immediately when a financial asset is originated or purchased. This new Current Expected Credit Losses (“CECL”) model applies to (1) loans, accounts receivable, trade receivables, and other financial assets measured at amortized cost, (2) loan commitments and certain other off-balance sheet credit exposures, (3) debt securities and financial assets measured at fair value, and (4) beneficial interests in securitized financial assets. This ASU was effective for SEC filers beginning after December 15, 2019; however, on November 15, 2019, the FASB issued ASU 2019-10, which delayed the effective date for “smaller reporting companies.” Therefore, ASU 2016-13 is effective for "smaller reporting companies" (as defined by the Securities and Exchange Commission) like us, for fiscal years beginning after December 15, 2022, including interim periods within those years, and must be adopted under the modified retrospective method. We adopted this standard effective January 1, 2022. The adoption of this standard did not have a material impact on our consolidated financial statements and cash flows.

NOTE 2 – OIL AND GAS PROPERTIES, EQUIPMENT AND FIXTURES

Oil and gas properties, equipment and fixtures consist of:

	Year ended December 31, 2023	2022
Oil and Gas		
Producing properties, including intangible drilling costs	$ 5,763,892	$ 5,712,436
Undeveloped properties	778,839	148,989
Lease and well equipment	3,295,028	3,317,718
	9,837,759	9,179,143
Accumulated depletion, depreciation and amortization	(7,443,661)	(7,142,506)
Net capitalized costs Total	$ 2,394,098	$ 2,036,637

Commercial and Other	2023	2022
Vehicles	40,061	40,061
Furniture and equipment	1,103,362	1,097,428
	1,143,423	1,137,489
Accumulated depreciation	(1,135,619)	(1,133,806)
	7,804	3,683
Net capitalized costs Total	$ 2,401,902	$ 2,040,320

The following sets forth costs incurred for oil and gas property acquisition and development activities, whether capitalized or expensed at December 31:

	Year ended December 31, 2023	2022
Acquisition - Proved	-	-
Acquisition - Unproved	-	-
Development	4,120,538	5,301,061
Exploration	-	-

The guidance set forth in the Continued Capitalization of Exploratory Well Costs paragraph of the Extractive Activities Topic of the FASB ASC 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 2023 and 2022. Undeveloped properties are not subject to depletion, depreciation or amortization.

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) are as follows:

	Year Ended December 31,	
	2023	2022
Oil and gas sales	$ 2,114,026	$ 2,611,222
Production related costs (Lease Operating)	(1,731,670)	(1,928,521)
Impairment	(1,599,001)	-
Depreciation, depletion and amortization	(346,866)	(575,909)
Results of operations from producing and exploration activities	(1,563,511)	106,792
Income Taxes (Benefit)	-	-
Net Results	$ (1,563,511)	$ 106,792

NOTE 3 – ASSET RETIREMENT OBLIGATION

The Asset Retirement and Environmental Obligations Topic of the ASC 410-20 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 the estimated fair value, and accretion expense will be recognized over time as the discounted liability is accreted to its expected settlement value. Accretion expense is included as part of Depreciation, Depletion and Amortization in the Consolidated Statement of Operations. The fair value (as provided in ASC 820 guidance) of the ARO is measured using expected future cash outflows discounted at our 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. For the year ended December 31, 2023, we recognized $996,852 related to the increase in expected cost of abandoning our California wells. There were no changes in estimates for the year ended December 31, 2022.

	2023	2022
Asset retirement obligation		
Beginning of the year	$ 3,542,479	$ 3,285,560
Liabilities incurred during the period	37,260	29,338
Settlements	(141,751)	(58,889)
Additions	387,359	-
Sales	(39,249)	-
Changes in estimates	996,852	-
Accretion expense	43,897	286,470
End of year	$ 4,826,847	$ 3,542,479

We record accretion expense as part of Depreciation, Depletion and Amortization. Accretion expense was $43,897 and $286,470 for the years ended December 31, 2023 and 2022, respectively.

NOTE 4 – 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.

Significant components of our deferred assets and liabilities at December 31, 2023 and 2022, respectively, are as follows:

	2023	2022
Deferred Tax Assets (Liabilities):		
Statutory Depletion Carry Forward	$ 310,903	$ 310,903
Net Operating Loss	9,171,527	8,542,098
Other	668,815	688,377
Share-Based Compensation	86,510	86,510
Capital Loss / AMT Credit Carry Forward	9,458	9,458
Charitable Contributions Carry Forward	2,702	100
Allowance for Doubtful Accounts	478,131	717,514
Oil and Gas Properties and Fixed Assets	5,088,608	4,976,399
Investment in RMX Joint Venture	67,371	(285,626)
	15,884,025	$ 15,045,733
Valuation Allowance	(15,884,025)	(15,045,733)
Net Deferred Tax Asset	$ -	$ -

We recorded a full valuation allowance against the net deferred tax assets in 2016. At the end of 2017, management reviewed the reliability of our net deferred tax assets, and due to our continued cumulative losses in recent years, we and our management concluded it is not “more-likely-than-not” our deferred tax assets will be realized. As a result, we will continue to record a full valuation allowance against the deferred tax assets. We will assess the realizability of the deferred tax assets at least yearly and make appropriate updates as needed. We and our subsidiaries have available net operating loss carryforwards of $20.5 million generated in tax years ended before January 1, 2018, which if not utilized, begin to expire in the year 2026. We have $12.0 million net operating loss carryforwards generated after December 31, 2017, which can be carried forward indefinitely.

A reconciliation of our provision for income taxes and the amount computed by applying the statutory income tax rates at December 31, 2023 and 2022, respectively, to pretax income is as follows:

	2023	2022
Tax (benefit) computed at statutory rate of 21%	$ (384,759)	$ (30,575)
Increase (decrease) in taxes resulting from:		
Meals & Entertainment	1,233	-
Employer Retention Credits	-	(31,527)
Prior-year true-up for Books	33,539	(221,621)
Deferred State Taxes, net of federal benefit	(499,164)	62,558
Other non-deductible expenses	10,859	2,024
Change in valuation allowance	838,292	219,141
Provision (benefit)	-	-

In January 2007, we adopted additional provisions from the Income Taxes Topic of the ASC, 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, 2018, we 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 2019 through 2022 remain open to examination by the taxing jurisdictions in which we file income tax returns.

NOTE 5 – SERIES B PREFERRED STOCK

Pursuant to the terms of the Merger all Class A limited partnership interests of Matrix Investments, LP ("Matrix Investments") were exchanged for our 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 our Series B Convertible Preferred Stock. Our Board of Directors, prior to the merger, authorized 3,000,000 shares of Series B Convertible Preferred, which carries a liquidation preference and a 3.5% annual dividend, payable quarterly in cash or Paid-In-Kind ("PIK") shares. The Series B Convertible Preferred Stock is convertible at the option of the security holder at the rate of ten shares of common stock for one share of Series B Convertible Preferred Stock. The Series B Preferred Stock has never been registered under the Securities Exchange Act of 1934, and no market exists for the shares. Additionally, the Series B Convertible Preferred shares will automatically convert to shares of common stock at any time in which the Volume Weighted Average Price ("VWAP") of the common stock exceeds $3.50 per share for 20 consecutive trading days, the shares of common stock are registered with the SEC and the volume of common shares trades exceeds 200,000 shares per day. The shareholders of the Series B Convertible Preferred may vote the number of shares into which they would be entitled to convert, beginning in 2020.

In accordance with ASC 480-10-S99-1.02, we have determined that the conversion or redemption of these shares are outside our sole control and that they should be classified in mezzanine or temporary equity as redeemable noncontrolling interest beginning at the reporting period, ended March 31, 2020.

For 2023 and 2022, the board authorized the payment of each quarterly dividend of Series B Convertible Preferred shares, as Paid-In-Kind shares ("PIK") to be paid immediately following the end of the quarter. For the 12 months ending December 31, 2023, we issued 62,899 shares with a value of $629,007, with 21,570 shares with a value of $215,693 accrued for but not yet issued at December 31, 2023. For the 12 months ending December 31, 2022, we issued 60,748 shares with a value of $607,465, of these 20,832 shares with a value of $208,307 were accrued as of December 31, 2022, and paid in the first quarter of 2023 but not yet issued. During 2023 and 2022, no cash was used to pay dividends on Series B preferred shares.

NOTE 6 – COMMON STOCK

During the years 2023 and 2022, we issued shares of our Common Stock in lieu of cash payments for salaries, fees or incentives to various officers and board members, including our CEO, as noted in the Statement of Stockholders' Deficit.

During the year ended December 31, 2023, CIC RMX LP ("CIC") exercised in full its warrant to purchase shares or our common stock. CIC elected to make a cashless exercise of warrant and as a result we issued 3,266,055 shares of our common stock to CIC.

NOTE 7 – LEASES

During 2023, we had one office lease at 1530 Hilton Head Road, El Cajon, California, the location of our corporate offices. The corporate office lease was entered into on August 12, 2021, began on January 1, 2022 and expires on December 31, 2026, with initial monthly payments of $6,922 with escalations. We also rent office space on a month-to-month basis at 104 W. Anapamu, Santa Barbara, California, the location of our CEO and engineering team.

We have elected the short-term lease recognition exemption for all leases that qualify. This means, for those leases that qualify, we will not recognize ROU assets or lease liabilities, and this includes not recognizing ROU assets or lease liabilities for existing short-term leases of those assets in transition. We elected the practical expedient to not separate lease and non-lease components for all of our finance leases. For our real estate operating leases, we have only considered the fixed portion of our lease payment commitment and have excluded the variable components from the capitalized ROU and lease liability.

Lease expense for operating as well as finance leases are included in General and Administrative expense and Interest Expense on the Consolidated Statement of Operations, while the lease expense for those leases that are short-term are included in Oil and Gas Lease Operating Expenses. The amounts are as follows:

	Year ended December 31, 2023	2022
Operating lease expense	$ 161,858	$ 174,975
Financing lease expense	17,322	19,076
Operating – short-term	-	-
Short Term - field	6,000	6,000
Total lease expense	$ 185,180	$ 200,051

The following tables summarized the operating and financing lease obligations.

Lease Obligations	Operating Lease Obligations	Financing Lease Obligations	Total Lease Obligations
2024	$ 88,128	$ 7,343	$ 95,471
2025	90,768	-	90,768
2026	93,492	-	93,492
Thereafter	-	-	-
Total undiscounted lease payments	272,388	7,343	279,731
Less: Amount representing interest	24,569	493	25,062
Total Operating & Financing lease liabilities	247,819	6,850	254,669
Current lease liabilities as of December 31, 2023	76,158	7,072	83,230
Long-term lease liabilities as of December 31, 2023	$ 171,661	$ (222)	$ 171,439

Our two office leases do not contain implicit interest rates that can be readily determined. As a result, we used the available risk-free rate plus 4 basis points. At December 31, 2023 and 2022, the weighted average discount rate was 4.83% and the term was 4 years.

NOTE 8 – RELATED-PARTY TRANSACTIONS

Our Chief Executive Officer, Johnny Jordan, has accrued certain unpaid salaries. At December 31, 2023, Mr. Jordan was owed $46,926, in accrued unpaid guaranteed payments.

Stephen Hosmer, former CFO, current director and corporate secretary At December 31, 2023, we had a receivable balance of $18,495 due from Stephen Hosmer for normal drilling and lease operating expenses.

At December 31, 2023 and 2022, we had a total payable of $23,087 and $23,087, respectively, due to RMX and its subsidiary, Matrix Oil Corporation, related to certain lease operating expenses for wells operated by RMX. For the same periods, we also had prepaid expenses and other current assets, and deferred drilling costs of $382,520 and $290,871, respectively. In 2023, the prepaid amount was for future plugging and abandonment costs. In 2022, the prepaid amount was for drilling and future plugging costs. During 2023, RMX Resources LLC operated various oil wells we have interests in, from which we received revenues of approximately $374,000 and incurred lease operating costs of approximately $181,000. At December 31, 2023 and 2022, we had a total revenue receivables of $120,634 and $127,360, respectively, due from RMX and its subsidiary, Matrix Oil Corporation.

We had outstanding accrued unpaid guaranteed payments for unpaid salaries for periods predating their joining our company due to certain former Matrix employees. At December 31, 2023, the balance due was $1,616,205. At December 31, 2023, Royale also had accrued unpaid liabilities of $1,306,605 due to certain former Matrix employees for periods predating their employment.

Michael McCaskey, a former director, and Jeffery Kerns, a current director, and Stephen Hosmer, a current director, each have consulting agreements to provide services as directed and at our discretion. Mr. Kerns' wife was a director during 2020 and 2021. At December 31, 2023 and 2022, we had total payables of $164,669 and $185,049, respectively, owed to current and former board members for directors fees.

NOTE 9 – STOCK COMPENSATION PLAN

There were no stock options issued during 2023 and 2022.

NOTE 10 – SIMPLE IRA PLAN

In April 1998, we established a Simple IRA pension plan covering all employees. We 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, 2023 and 2022, were $26,051 and $27,770 respectively.

NOTE 11 – ENVIRONMENTAL MATTERS

We have established procedures for the continuing evaluation of our operations to identify potential environmental exposures and ensure compliance with regulatory policies and procedures. Management monitors these laws and regulations and periodically assesses the propriety of our operational and accounting policies related to environmental issues. The nature of our business requires routine day-to-day compliance with environmental laws and regulations. We incurred no material environmental investigation, compliance and remediation costs in 2023 or 2022.

We are unable to predict whether our 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 our results of operations.

NOTE 12 – CONCENTRATIONS

We bid our gas sales on a month-to-month basis and generally sell to a single customer without commitment to future gas sales to any particular customer. We normally sell approximately 45% of our yearly 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.

We maintain 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, 2023, and 2022. At December 31, 2023 and 2022, cash in banks exceeded the FDIC limits by approximately $5.3 million and $3.6 million, respectively. We have not experienced any losses on deposits.

NOTE 13 – COMMITMENTS AND CONTINGENCIES

We may become involved from time to time in litigation on various matters, which are routine to the conduct of our business. We believe that none of these actions, individually or in the aggregate, will have a material adverse effect on our 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 our business.

We sponsor turnkey drilling agreement arrangements in proved and unproved properties as a pooling of assets in a joint undertaking, whereby proceeds from participants are reported as Deferred Drilling Obligations. The contracts require the participants pay us the full contract price upon execution of the agreement. We typically begin the drilling activities within 12 months of funding and reach total depth between 10 and 30 days after drilling begins.

NOTE 14 – SUBSEQUENT EVENTS

We have evaluated subsequent events through April 12, 2024, the date of issuance of these consolidated financial statements. At March 1, 2024, we issued 21,570 shares of our Series B Preferred stock with a value of $215,693 for our fourth quarter 2023 dividend that had been accrued for but not yet issued at December 31, 2023.We are not aware of events which would require recognition or disclosure in the financial statements, except as noted here or already recognized or disclosed.

On February 7, 2024 the board of directors approved a debt facility of up to $3 million. On February 9, 2024, Royale Energy, Inc. entered into a Secured Term Loan Note with Walou Investments, LP, a Texas limited partnership, which is under the direct and indirect control of Johnny Jordan, the Company's Chief Executive Officer and a member of the Company's Board of Directors. In addition, Mr. Jordan is the beneficial owner of 14.8% of the Company's issued and outstanding common stock. The initial loan to the Company was $1,400,000 which was received on February 9, 2024. The outstanding principal balance of the loan has an interest rate of 18.00%. The Company will make monthly interest payments starting on March 1, 2024 until the maturity date.

NOTE 15 – SUPPLEMENTAL INFORMATION ABOUT OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interest we owned, 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 our proved developed and undeveloped reserves was approximately $10.7 million at December 31, 2023, based on the average Henry Hub natural gas price spot price of $2.637 per MCF and for oil volumes, the average West Texas Intermediate price of $78.21 per barrel as applied on a field-by-field basis. Netherland, Sewell & Associates, Inc. provided reserve value information for our California, Texas, and Oklahoma 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 by our management.

These estimates are furnished and calculated in accordance with requirements of the FASB and the 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 our management's assessment of future profitability or future cash flows. 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, 2023 and 2022, and changes in such quantities during each of the years then ended, were as follows:

Total Proved Reserves

	2023		2022	
	Oil (BBL)	**Gas (MCF)**	**Oil (BBL)**	**Gas (MCF)**
Beginning of period	372,300	1,133,300	1,579,100	1,354,300
Revisions of previous estimates	(185,261)	(720,023)	(1,283,285)	(85,864)
Production	(22,399)	(128,160)	(18,015)	(135,136)
Extensions, discoveries and improved recovery	53,140	188,423	94,500	-
Merger Acquisition	-	-	-	-
Purchase of minerals in place	-	-	-	-
Sales of minerals in place	-	-	-	-
Proved reserves end of period	217,780	473,540	372,300	1,133,300

Proved Developed

	2023		2022	
	Oil (BBL)	**Gas (MCF)**	**Oil (BBL)**	**Gas (MCF)**
Proved developed reserves:				
Beginning of period	182,000	942,000	193,600	939,100
End of period	138,060	357,940	182,000	942,000

Proved Undeveloped

	2023		2022	
	Oil (BBL)	**Gas (MCF)**	**Oil (BBL)**	**Gas (MCF)**
Proved undeveloped reserves:				
Beginning of period	190,300	191,300	1,385,500	415,200
End of period	79,720	115,600	190,300	191,300

During 2023, our overall proved developed and undeveloped oil reserves decreased by 41.5% and our previously estimated proved developed and undeveloped oil reserve quantities were revised downward by approximately 185 thousand barrels. This downward revision was mainly the result of a decrease in proved undeveloped oil reserves from drilling locations which the Company had previously estimated. Our overall proved developed and undeveloped natural gas reserves decreased by 58.2% and our previously estimated proved developed and undeveloped natural gas reserve quantities were revised downward by approximately 720 thousand cubic feet of natural gas. This downward revision was mainly the result of a decrease in proved undeveloped natural gas reserves from drilling locations which we had previously estimated.

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

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:

2024	$	8,200
2025		-
2026		-
Thereafter		-
	$	8,200

The resulting future net revenue streams are reduced to present value amounts by applying a 10 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.

Changes in standardized measure of discounted future net cash flow from proved reserve quantities

The standardized measure of discounted future net cash flows is presented below for the years ended December 31, 2023, and 2022.

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 10 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.

	2023	2022
Future cash inflows	$ 17,559,800	$ 38,766,900
Future production costs	(6,860,800)	(14,094,900)
Future development costs	(8,200)	(1,378,500)
Future income tax expense	(3,207,240)	(6,988,050)
Future net cash flows	7,483,560	16,305,450
10% annual discount for estimated timing of cash flows	(3,011,664)	(6,044,467)
Standardized measure of discounted future net cash flows	4,471,896	10,260,983
Sales of oil and gas produced, net of production costs	(322,560)	(608,735)
Revisions of previous quantity estimates	(10,359,602)	(12,855,765)
Net changes in prices and production costs	946,740	(287,425)
Sales of minerals in place	-	-
Extensions, discoveries and improved recovery	2,067,392	4,266,500
Accretion of discount	(602,094)	884,088
Net change in income tax	2,481,037	2,580,401
Net increase (decrease)	$ (5,789,087)	$ (6,020,936)

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 year 2024.

	2024
Future development cost of:	
Proved developed reserves (PDP)	$ -
Proved non-producing reserves (PDNP)	8,200
Proved undeveloped reserves (PUD)	-
Total	$ 8,200

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 our oil and natural gas properties is disclosed in Supplemental Information About Oil and Gas Producing Activities (Unaudited), attached to our Financial Statements, in Note 15.

Historic Development Costs for Proved Reserves

In each year we expend funds to drill and develop some of our proved undeveloped reserves. We have incurred no cost in any 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.

Exhibit 21.1

ROYALE ENERGY, INC.
SUBSIDIARIES
December 31, 2023

Royale Energy Funds, Inc
Matrix Permian Investment, L.P.
Matrix Investment, L.P.
Royale DWI Investors, LLC
Matrix Oil Management, Corp.
Matrix Pipeline, L.P. (Limited Partner only, General Partner is Matrix Oil Corp. part of the RMX Joint Venture)

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement on Form S-8 (No. 333-228028) of Royale Energy, Inc. (the “Company”) of our report dated March 14, 2024, relating to the consolidated financial statements of the Company as of and for the year ended December 31, 2022 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to a going concern uncertainty), appearing in the Annual Report on Form 10-K of the Company for the year ended December 31, 2023.

/s/ HORNE, LLP.

Ridgeland, Mississippi
April 12, 2024

Exhibit 23.2

NETHERLAND, SEWELL & ASSOCIATES, INC.

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

We hereby consent to the inclusion of our report of Royale Energy, Inc. (the “Company”) dated February 14, 2024, in the Annual Report on Form 10-K for the year ended December 31, 2023, of the Company and its subsidiaries, to be filed with the Securities and Exchange Commission.

NETHERLAND, SEWELL & ASSOCIATES, INC.

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

Houston, Texas
March 25, 2024

Exhibit 31.1

I, Johnny Jordan, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy, 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: April 12, 2024 By: */s/ Johnny Jordan*

Johnny Jordan, Chief Executive Officer

Exhibit 31.2

I, Ronald Lipnick, certify that:

1. I have reviewed this report on Form 10-K of Royale Energy, 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: April 12, 2024   By: */s/ Ronald Lipnick*
Ronald Lipnick, Interim Chief Financial Officer

Exhibit 32.1

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

The undersigned, Johnny Jordan, Chief Executive Officer of Royale Energy, Inc., a Delaware 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, to his knowledge:

(1) the Company's Annual Report on Form 10-K for the year ended December 31, 2023 (the "Report") fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: April 12, 2024	By:	*/s/ Johnny Jordan*
		Johnny Jordan, Chief Executive Officer

This certification accompanies this Report on Form 10-K pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by such Act, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

Exhibit 32.2

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

The undersigned, Ronald Lipnick, Interim Chief Financial Officer of Royale Energy, Inc., a Delaware 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, to his knowledge:

(1) the Company’s Annual Report on Form 10-K for the year ended December 31, 2023 (the “Report”) fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

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

Date: April 12, 2024	By:	*/s/ Ronald Lipnick*
		Ronald Lipnick, Interim Chief Financial Officer

This certification accompanies this Report on Form 10-K pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 and shall not, except to the extent required by such Act, be deemed filed by the Company for purposes of Section 18 of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Such certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, as amended, or the Exchange Act, except to the extent that the Company specifically incorporates it by reference.

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

February 14, 2024

Mr. Johnny Jordan
Royale Energy, Inc.
1530 Hilton Head Road, Suite 205
El Cajon, California 92019

Dear Mr. Jordan:

In accordance with your request, we have estimated the proved reserves and future revenue, as of December 31, 2023, to the Royale Energy, Inc. (Royale) interest in certain oil and gas properties located in California, Oklahoma, and Texas. 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 conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities—Oil and Gas, except that future income taxes are excluded and, as requested, abandonment costs have only been included in our estimates of future net revenue for proved undeveloped properties. 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, 2023, to be:

	Net Reserves		Future Net Revenue (M$)	
Category	Oil (MBBL)	Gas (MMCF)	Total	Present Worth at 10%
Proved Developed Producing	120.5	322.8	5,098.5	3,115.4
Proved Developed Non-Producing	17.6	35.1	,622.9	522.5
Proved Undeveloped	79.7	115.6	4,969.3	2,865.9
Total Proved	217.8	473.5	10,690.8	6,503.7

Totals may not add because of rounding.

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info@nsai-petro.com
netherlandsewell.com

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, abandonment costs, and operating expenses but before consideration of any income taxes. The future net revenue has been discounted at an annual rate of 10 percent to determine its present worth, which is shown to indicate the effect of time on the value of money. Future net revenue presented in this report, whether discounted or undiscounted, should not be construed as being the fair market value of the properties.

Prices used in this report are based on the 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December 2023. For oil volumes, the average West Texas Intermediate spot price of $78.21 per barrel is adjusted by field for quality, transportation fees, and market differentials. For gas volumes, the average Henry Hub spot price of $2.637 per MMBTU is adjusted by field for energy content, transportation fees, and market differentials. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $74.42 per barrel of oil and $2.855 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. Operating costs have been divided into per-well costs and per-unit-of-production costs. 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 and production equipment. Based on our understanding of future development plans, a review of the records provided to us, and our knowledge of similar properties, we regard these estimated capital costs to be reasonable. Abandonment costs used in this report for proved undeveloped properties are Royale's estimates of the costs to abandon the wells and production facilities, net of any salvage value. As requested, our estimates for all other properties do not include any salvage value for the lease and well equipment or the cost of abandoning the properties. Capital costs and abandonment costs are not escalated for inflation.

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

We have made no investigation of potential volume and value imbalances resulting from overdelivery or underdelivery to the 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 specific investigation of any firm transportation contracts that may be in place for these properties; our estimates of future revenue include the effects of such contracts only to the extent that the associated fees are accounted for in the historical field- and lease-level accounting statements.

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 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. 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. Edward C. Roy III, a Licensed Professional Geoscientist in the State of Texas, has been practicing consulting petroleum geoscience at NSAI since 2008 and has over 11 years of prior industry experience. We are independent petroleum engineers, geologists, geophysicists, and petrophysicists; we do not own an interest in these properties nor are we employed on a contingent basis.

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

Texas Registered Engineering Firm F-2699

By: /s/ Richard B. Talley, Jr.
Richard B. Talley, Jr., P.E.
Chief Executive Officer

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

Date Signed: February 14, 2024

By: /s/ Edward C. Roy III
Edward C. Roy III, P.G. 2364
Vice President

Date Signed: February 14, 2024

CAS:KJL

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 2018 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 2018 Petroleum Resources Management System:

Developed Producing Reserves – Expected quantities to be recovered from completion intervals that are open and producing at the effective date of the estimate. Improved recovery Reserves are considered producing only after the improved recovery project is in operation.

Developed Non-Producing Reserves – Shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals that 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 that will require additional completion work or future re-completion before start of production with minor cost to access these reserves. 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
(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.