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

Form 10-K

☒ **Annual Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934:**

For the Fiscal Year Ended December 31, 2014

☐ **Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934.**

For the transition period from __________ to __________

Commission File Number 33-16820-D

ARÊTE INDUSTRIES, INC.
(Exact name of registrant as specified in its charter)

Colorado **(State or Other Jurisdiction of Incorporation or Organization)**	**84-1508638** **(I.R.S. Employer Identification No.)**
7260 Osceola Street, Westminster, Colorado **(Address of Principal Executive Offices)**	**80030** **(Zip Code)**

(303) 427-8688
(Registrant's Telephone Number, Including Area Code)

Securities registered under Section 12(b) of the Exchange Act: None

Securities registered under Section 12(g) of the Exchange Act: None

Name of Exchange on which registered: None

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 Section 15(d) of the Act. Yes ☐ No ☒

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

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

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

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

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☐	Smaller reporting company	☒

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

On June 30, 2014, the aggregate market value of the 7,641,552 shares of common stock held by non-affiliates of the Registrant was approximately $2,674,543

As of April 14, 2015, the Registrant had 12,558,459 shares of common stock issued and outstanding.

Documents Incorporated By Reference - None

[1] Explanatory Note: The Company is a voluntary filer with the Securities and Exchange Commission but it has filed all Exchange Act reports for the preceding 12 months.

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Arête Industries, Inc.

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Cautionary Statement Regarding Forward-Looking Statements

Certain statements contained in this Annual Report on Form 10-K (and other documents to which it refers) are not statements of historical fact and constitute forward-looking statements within the meaning of the various provisions of the Securities Act of 1933, as amended, which we refer to as the Securities Act, and the Securities Exchange Act of 1934, as amended, which we refer to as the Exchange Act, including, without limitation, the statements specifically identified as forward-looking statements within this Annual Report on Form 10-K. Many of these statements contain risk factors as well. In addition, certain statements in our future filings with the SEC, in press releases, and in oral and written statements made by or with our approval, which are not statements of historical fact, constitute forward-looking statements within the meaning of the Securities Act and the Exchange Act. Examples of forward-looking statements, include, but are not limited to: (i) projections of capital availability, terms, expenditures, revenues, income or loss, earnings or loss per share, the payment or non-payment of dividends on our common stock and on our convertible preferred stock, capital structure, and other financial items, (ii) statements of our plans and objectives or our management or board of directors including those relating to possible development of our oil and gas properties, (iii) statements of future economic performance and (iv) statements of assumptions underlying such statements. Words such as "believes", "anticipates", "expects", "intends", "targeted", "may", "will" and similar expressions are intended to identify forward-looking statements but are not the exclusive means of identifying such statements. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to:

- our ability to alleviate our significant working capital deficit and continue business as a going concern
- changes in production volumes, worldwide demand and commodity prices for oil and natural gas;
- changes in estimates of proved reserves;
- declines in the values of our oil and natural gas properties resulting in impairments;
- the timing and extent of our success in discovering, acquiring, developing and producing oil and natural gas reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- risks incident to the drilling and operation of oil and natural gas wells;
- future production and development costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America;
- changes in environmental laws and the regulation and enforcement related to those laws;
- the identification of and severity of environmental events and governmental responses to the events;
- the effect of oil and natural gas derivatives activities; and
- conditions in the capital markets.

Such forward-looking statements speak only as of the date on which such statements are made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made to reflect the occurrence of unanticipated events.

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CERTAIN DEFINITIONS

Unless the context in this Annual Report on Form 10-K otherwise requires, the terms the "Company", "we", "us", "our" or "ours" when used herein refers to Arête Industries, Inc., together with its consolidated subsidiary. When the context requires, we refer to these entities separately. We have included below the definitions for certain terms used in this Annual Report on Form 10-K:

Bbl – One stock tank barrel, or 42 U.S. gallons liquid volume, used herein in reference to crude oil or other liquid hydrocarbons.

Bbls/d or ***BOPD*** – barrels per day or barrels of oil per day.

BOE – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

Carried interest – A contractual arrangement, usually in a drilling project, whereby all or a portion of the working interest cost participation of the project originator is paid for by another party in exchange for earning an interest in such project.

Completion – The installation of permanent equipment for the production of oil or natural gas or, in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Compression – A force that tends to shorten or squeeze, decreasing volume or increasing pressure.

DD&A – Depreciation, depletion, amortization and accretion.

Developed acreage – The number of acres which are allotted or assignable to producing wells or wells capable of production.

Development activities – Activities following acquisition or exploration including the drilling and completion of additional wells and the installation of production facilities.

Development well – A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole or well – A well found to be incapable of producing hydrocarbons economically.

Exploitation – The act of making an oil and gas property more profitable, productive or useful.

Exploratory well – A well drilled to find oil or natural gas reserves in an area or to a potential reservoir not classified as proved.

Farm-in or ***Farm-out*** – An agreement whereby the owner of a working interest in an oil and natural gas lease assigns or contractually conveys subject to future assignment the working interest or a portion thereof to another party who desires to drill on the leased acreage. Generally, the farmee is required to drill one or more wells in order to earn its interest in the acreage. The farmor usually retains a royalty and/or after payout interest in the lease. The interest received by the farmee is a "farm-in" while the interest transferred by the farmor is a "farm-out."

FASB – The Financial Accounting Standards Board.

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.

GAAP – Generally accepted accounting principles in the United States of America.

Gross acres or gross wells – The total acres or wells, as the case may be, in which a working interest is owned.

Mbtu (Mmbtu) – Used as a standard unit of measurement for natural gas and provides a convenient basis for comparing the energy content of various grades of natural gas and other fuels. One cubic foot of natural gas produces approximately 1,000 BTUs, so 1,000 cubic feet of gas is comparable to 1 Mbtu. Mbtu is often expressed as MMbtu, which is intended to represent a thousand BTUs.

Mcf – One thousand cubic feet.

Mmcf – One million cubic feet.

Net acres or net wells – The sum of the fractional working interests owned in gross acres or gross wells.

NGL's – Natural gas liquids measured in barrels.

NRI or ***Net Revenue Interests*** – The share of production after satisfaction of all royalty, oil payments and other non-operating interests.

Plugging and abandonment or ***P&A*** – Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface.

PV10 – The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated lease operating expense, production taxes and future development costs, using prices and costs, as prescribed in the SEC rules, as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service, depreciation, depletion, amortization and accretion, or Federal income taxes and discounted using an annual discount rate of 10%. PV10 is considered a Non-GAAP financial measure as defined by the SEC.

Productive well – A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production taxes and lease operating expenses.

Proved developed nonproducing reserves or ***PDNP*** – Proved reserves that meet the definition of proved developed reserves (defined below) but are either shut-in or are behind-pipe reserves.

Proved developed producing reserves or ***PDP*** – Proved reserves that meet the definition of proved developed reserves (defined below) that are currently able to produce to market.

Proved developed reserves – Proved developed oil and gas reserves are reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the costs of the required equipment is relatively minor compared to the costs of a new well.

Proved 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 estimates. 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.

Proved undeveloped reserves or ***PUDs*** – Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. 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

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 90 percent 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 or geochemical) engineering, and economic data are made to estimated ultimate recovery with time, reasonably certain estimated ultimate recovery is much more likely to increase or remain constant than to decrease.

Re-engineering – a process involving a comprehensive review of the mechanical conditions associated with wells and equipment in producing fields. Our re-engineering practices typically result in a capital expenditure plan, which is implemented over time, to workover (see below) and re-complete wells and modify down-hole artificial lift equipment and surface equipment and facilities. The programs are designed specifically for individual fields to increase and maintain production, reduce down-time and mechanical failures, lower per-unit operating expenses, and therefore, improve field economics.

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

Royalty interest – An interest in an oil and natural gas property entitling the owner to a share of oil or natural gas production free of costs of production.

SEC – The U.S. Securities and Exchange Commission.

Secondary recovery – The use of water-flooding or gas injection to maintain formation pressure during primary production and to reduce the rate of decline of the original reservoir drive.

Shut-in reserves – Those reserves expected to be recovered from completion intervals that were open at the time the reserves were estimated but were not producing due to market conditions, mechanical difficulties or because production equipment or pipelines were not yet installed. These reserves are included in the PDNP category on the reserve report.

Standardized Measure of Discounted Future Net Cash Flows – A measure of the present value of the estimated future cash flows to be derived from the production and sale of proved oil and gas reserves. Estimated production taxes, estimated operating expenses, estimated future investment costs, and estimated future income taxes are deducted from estimated future cash inflows and discounted at PV 10 to arrive at the standardized measure of discounted future net cash flows. We calculate this measure in accordance with FASB ASC Topic (932) *Extractive Activities – Oil and Gas*.

Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest or **WI** – The ownership interest, generally defined in a joint operating agreement, that gives the owner the right to drill, produce and/or conduct operating activities on the property and share in the sale of production, subject to all royalties, overriding royalties and other burdens and obligates the owner of the interest to share in all costs of exploration, development, and production and all risks in connection therewith.

Workover – Major remedial operations on a completed well to restore, maintain or improve the well's production.

PART 1

Item 1. BUSINESS

Overview

Arête Industries, Inc., a Colorado corporation, is an independent oil and gas company engaged in the acquisition and development of oil and natural gas reserves through a program which includes purchases of reserves, re-engineering, development and exploration activities primarily focused in Wyoming, Kansas, Colorado and Montana.

In September 2006, we acquired a gas gathering system (pipeline and compressor station related assets) in Campbell County, Wyoming. This system was constructed in late 2001 and began operations early in 2002. The system consists of 4.5 miles of 8-inch coated steel pipeline. During the first half of 2011, this pipeline was transporting approximately 900,000 Mcf (thousand cubic feet) of coal bed methane per day and was cash flowing from its operations until June 2011 when the operator shut-in the coal bed methane wells due to the low prices received for the natural gas produced. This system has a current throughput capacity of approximately 4 million cubic feet of gas per day, although the system is currently idle since the related wells are shut-in.

On May 25, 2011, we entered into a purchase and sale agreement and other related agreements and documents with Tucker Family Investments, LLLP; DNR Oil & Gas, Inc. which we refer to as DNR; and Tindall Operating Company, which we refer to as Tindall, and collectively we refer to these parties as the Sellers, for the purchase of certain oil and gas operating properties in Colorado, Kansas, Wyoming, and Montana, which we refer to collectively as the original purchase and sale agreement. DNR is owned primarily by an officer and director of the Company, Charles B. Davis. The consideration for the purchase was determined by bargaining between management of the Company and Mr. Davis, and the Company used reports of independent engineering firms to analyze the purchase price. The base purchase price was paid in full on September 29, 2011. The Company may be obligated to make additional payments under the amended purchase and sale agreement if the Company increases its proven producing net oil reserves or net gas reserves by drilling or recompletion on certain of the acquired properties in Colorado and Kansas, then the Company will pay $250,000 for every 20,000 bbls or 150,000 mcf increase respectively. If the Nymex prices for oil and/or gas stay above certain thresholds for more than 60 days, the Company will also be required to pay an additional $250,000 as each threshold is exceeded for more than 60 consecutive days. Cumulative payments under the additional purchase price factor for the Colorado and Kansas properties are limited to $5 million. The Company will also make similar payments to the Sellers if the Company increases reserves in the Wyoming and Montana properties, and the Company will make additional payments under a formula by which Sellers and the Company will share proceeds of sales or production from untapped formations on the properties acquired in Wyoming and Montana. Cumulative payments under the additional purchase price factor for the Wyoming and Montana properties are limited to $20 million. The aggregate of all additional purchase price payments from all factors and all states is capped at $25 million. Due to consideration retained by the related party sellers from sales of properties during 2012, and $250,000 of consideration paid in December 2012 and an additional $250,000 of contingent consideration due to sustained increases in oil prices over $100 per barrel, and sale of a third property in 2013, the maximum future consideration has been reduced by approximately $5.8 million to $19.2 million as of December 31, 2014.

In the first quarter of 2012, we sold one of our producing properties in Wyoming, which resulted in gross proceeds of approximately $1,109,000. This property was sold to an unrelated purchaser and pursuant to our amended purchase agreement entered into in July 2011, we were required to pay the related party sellers approximately $283,000 of the proceeds due to their contingent interest and, as a result our net proceeds were $826,000. After deducting the net book value of the property of $309,000, plus the asset retirement obligation assumed by the unrelated purchaser of $16,000, we recognized a gain of approximately $533,000. During the fourth quarter of 2013, we sold one of our producing properties in Wyoming, which resulted in gross proceeds of approximately $1,004,000. This property was sold to an unrelated purchaser and pursuant to our amended purchase agreement entered into in September 2013, we were required to pay the related party sellers approximately $554,000 of the proceeds due to their contingent interest and, as a result our net proceeds were $450,000. After deducting the net book value of the property of $163,000, plus the asset retirement obligation assumed by the unrelated purchaser of $31,000, we recognized a gain of approximately $318,000. We received an overriding royalty interest on each of these properties.

Part of our strategy is to monitor the current production of our properties, seek to develop them with infield drilling, and explore sales and purchases of additional leases and operating wells with upside. We are currently evaluating several opportunities for drilling in Wyoming and Colorado. As part of our evaluation we have entered into participating agreements for five wells in Wyoming. The Company has participated as a working interest owner in the four horizontal wells which were drilled and completed in Campbell County, Wyoming in the Turner zone and the one well in Converse County, Wyoming in the Turner Zone. The following is a description of the wells:

1) The Thielen #1-21 is in Section 21 Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,350 including the lateral. The Company has an approximate 1.06% working interest. We had production from this well for eleven months in 2014 and the production is ongoing.

2) The Thielen #2-21 is in Section 21 Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,330 feet including the lateral. The Company has an approximate 1.06% working interest. We had production from this well for seven months in 2014 and the production is ongoing.

3) The Starlight Federal 28H is located in Section 7, Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,310 including the lateral. The Company has an approximate 0.7025% working interest. We had production from this well for 10 months in 2014 and the production is ongoing.

4) The Starlight Federal 30H is located in Section 7, Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,310 including the lateral. The Company has an approximate 1.450088% working interest. We had no production from this well in 2014 and the production is ongoing.

5) The Wibaux Gold Federal 4076-10-03-1SH is located in Section 10, Township 43N Converse County Wyoming. This well was drilled to a total depth of approximately 20,185 including the lateral. The Company has an approximate 0.2697755% working interest. We had one month production from this well in 2014 and the production is ongoing.

The following table provides information regarding our oil and natural gas properties and operations by state where the properties are located:

State	Proved Reserves at 2014 Year-End: Quantity (BOE) *(a)*	Pre-Tax PV 10% *(b)*	% Oil *(c)*	Productive Wells During 2014: Gross	Net *(d)*	2014 Average Monthly Production (BOE)
Wyoming	121,233	$2,346,812	67.4%	32.0	21.0	1,693
Kansas	119,948	2,806,158	100.0%	8.0	4.3	544
Colorado	85,677	1,964,952	38.5%	7.0	6.7	582
Montana	6,163	24,538	0.0%	2.0	1.4	59
	333,021	$7,142,460	68.8%	49.0	33.4	2,878

(a) BOE is defined as one barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of oil.
(b) The prices used to calculate this measure were $84.09 per barrel of oil and $6.09 per Mcf for natural gas. These prices were computed by applying the SEC-mandated 12 month arithmetic average of the first of month price for January through December 31, 2014, which resulted in benchmark prices of $94.99 per barrel for crude oil and $4.35 per MMbtu for natural gas. Benchmark prices were further adjusted on a well by well basis for transportation, quality and basis differentials to arrive at the prices used for this report.
(c) Computed based on BOE using the ratio of six Mcf of natural gas to one barrel of oil.
(d) Net wells are the sum of our fractional working interests owned in gross wells.

Reconciliation of Standardized Measure to PV10

PV10 is the estimated present value of the future net revenues from our proved oil and natural gas reserves before income taxes discounted using a 10% discount rate. PV10 is considered a non-GAAP financial measure because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV10 is an important measure that can be used to evaluate the relative significance of our oil and natural gas properties and that PV10 is widely used by securities analysts and investors when evaluating oil and natural gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, we believe the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that many other companies in the oil and natural gas industry calculate PV10 on the same basis. PV10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes. The table below provides a reconciliation of our standardized measure of discounted future net cash flows to our PV10 value:

	Standardized Measure	PV 10
Future cash inflows	$23,132,987	$23,132,987
Future production costs	(9,732,541)	(9,732,541)
Future development costs	(781,442)	(781,442)
Future income taxes	(1,905,627)	—
Future net cash flows	10,713,377	12,619,004
10% annual discount	(4,724,250)	(5,476,544)
Discounted future net cash flows	$ 5,989,127	$ 7,142,460

The difference between the standardized measure of $5,989,127 and PV10 of $7,142,460 is $1,153,333 which is due to income taxes included in the standardized measure as follows:

Undiscounted income taxes	$ 1,905,627
Impact of 10% discount factor	(752,294)
Discounted impact of income taxes	$ 1,153,333

Business Strategy

Our business strategy is three-fold in approach.

- We plan to and have acquired oil and natural gas operating properties that will provide for the operations of the Company;
- We expect to seek to acquire leases that have development possibility either for us to drill or with other companies on a joint venture or farm-out basis. Part of this plan would include the possibility of selling leases and retaining an overriding royalty in the property and a right to buy back into future development; and
- We are looking for acquisitions of producing properties with future development.

Competitive Business Conditions

The oil and natural gas industry is intensely competitive, and we compete with numerous other companies engaged in the exploration and production of oil and gas. Many of these companies have substantially greater resources than we have. Not only do they explore for and produce oil and natural gas, but also many carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. The operations of other companies are in many instances able to pay more for exploratory prospects and productive oil and natural gas properties. Many of our competitors also have more resources to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or technical resources permit.

Our larger competitors have the resources to be better able to absorb the burden of current and future federal, state, and local laws and regulations more easily than we can, which adversely affects our competitive position. Our ability to locate reserves and acquire interests in properties in the future will be dependent upon our ability and resources to evaluate and select suitable properties and consummate transactions in this highly competitive environment. In addition, we may be at a disadvantage in acquiring producing oil and natural gas properties and bidding for exploratory prospects because we have fewer financial and technical resources than other companies in our industry.

Members of the Organization of Petroleum Exporting Countries establish prices and production quotas for petroleum products from time to time with the intent of affecting the current global supply of crude oil and maintaining, lowering or increasing certain price levels. A drastic reduction in crude oil prices and related products from nearly $100 per barrel at mid-year 2014 to as low as $45 per barrel in early 2015 has negatively impacted the oil and gas industry. As of April 13, 2015, the price of crude oil was approximately $51 per barrel. Continuation of these steep declines put us at a disadvantage compared to many of our competitors due to their greater financial resources and ability to withstand such significant price declines.

Marketing and Customers

The market for oil and natural gas that we produce depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is expected to be sold at prices tied to the spot oil markets, as adjusted for transportation and quality. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We currently rely on our related party operator to market and sell our production.

Seasonality—Gathering and Processing

Generally, but not always, the demand and price levels for natural gas increase during the colder winter months and decrease during the warmer summer months. More recently, historical natural gas prices have been at ten year lows. In addition, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer, which can lessen seasonal demand fluctuations. Seasonal anomalies such as mild winters and summers sometimes lessen these fluctuations.

Foreign Operations and Export Sales

We do not have any interests, production facilities, or operations in foreign countries.

Governmental Regulations

Our operations are subject to significant, substantive rules, regulations and limitations impacting the oil and natural gas exploration and production industry as a whole, as described below.

Oil and Natural Gas Production

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state, and local authorities and agencies. Certain states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and gas industry has increased our cost of doing business and affected our profitability. Although we believe we are currently in substantial compliance with all applicable laws and regulations, because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations.

Transportation of Natural Gas

Historically, the transportation of natural gas in interstate commerce has been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the Federal Energy Regulatory Commission **(**FERC**).**

In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. The FERC's orders are intended to foster increased competition within all phases of the natural gas industry.

We cannot accurately predict whether the FERC's actions will achieve the goal of increasing competition. Therefore, we cannot provide any assurance that the less stringent regulatory approach established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects our competitors

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors.

Environmental Matters

All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas properties, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the establishment of maximum allowable rates of production from fields and individual wells. Our operations are also subject to various conservation laws and regulations. These laws and regulations govern the size of drilling and spacing units, the density of wells that may be drilled in oil and natural gas properties and the unitization or pooling of oil and natural gas properties. In this regard, some states allow the forced pooling or integration of land and leases to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of land and leases. In areas where pooling is primarily or exclusively voluntary, it may be difficult to form spacing units and therefore difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas, and impose specified requirements regarding the ratability of production. On some occasions, tribal and local authorities have imposed moratoria or other restrictions on exploration and production activities pending investigations and studies addressing potential local impacts of these activities before allowing oil and natural gas exploration and production to proceed.

The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Environmental Regulations

Our operations are subject to stringent federal, state and local laws regulating the discharge of materials into the environment or otherwise relating to health and safety or the protection of the environment. Numerous governmental agencies, such as the United States Environmental Protection Agency, commonly referred to as the EPA, issue regulations to implement and enforce these laws, which often require difficult and costly compliance measures. Among other things, environmental regulatory programs typically regulate the permitting, construction and operation of a facility. Many factors, including public perception, can materially impact the ability to secure an environmental construction or operation permit. Failure to comply with environmental laws and regulations may result in the assessment of substantial administrative, civil and criminal penalties, as well as the issuance of injunctions limiting or prohibiting our activities. In addition, some laws and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, which could result in liability for environmental damages and cleanup costs without regard to negligence or fault on our part.

New programs and changes in existing programs, however, may address various aspects of our business including natural occurring radioactive materials, oil and natural gas exploration and production, air emissions, waste management, and underground injection of waste material. Environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements could have a material adverse effect on our financial condition and results of operations. The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, earnings and competitive position.

Hazardous Substances and Wastes

The federal Comprehensive Environmental Response, Compensation and Liability Act, referred to as CERCLA or the Superfund law, and comparable state laws impose liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons may include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances that have been released at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the costs of some health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment.

Under the federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, referred to as RCRA, most wastes generated by the exploration and production of oil and natural gas are not regulated as hazardous waste. Periodically, however, there are proposals to lift the existing exemption for oil and natural gas wastes and reclassify them as hazardous wastes. If such proposals were to be enacted, they could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. In the ordinary course of our operations moreover, some wastes generated in connection with our exploration and production activities may be regulated as solid waste under RCRA, as hazardous waste under existing RCRA regulations or as hazardous substances under CERCLA. From time to time, releases of materials or wastes have occurred at locations we own or at which we have operations. These properties and the materials or wastes released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we have been and may be required to remove or remediate such materials or wastes.

Water Discharges

Our operations are also subject to the federal Clean Water Act and analogous state laws. Under the Clean Water Act, the EPA has adopted regulations concerning discharges of storm water runoff. This program requires covered facilities to obtain individual permits, or seek coverage under a general permit. Some of our properties may require permits for discharges of storm water runoff. We believe that we will be able to obtain, or be included under, these permits, where necessary, and make minor modifications to existing facilities and operations that would not have a material effect on us. The Clean Water Act and similar state acts regulate other discharges of wastewater, oil, and other pollutants to surface water bodies, such as lakes, rivers, wetlands, and streams. Failure to obtain permits for such discharges could result in civil and criminal penalties, orders to cease such discharges, and costs to remediate and pay natural resources damages. These laws also require the preparation and implementation of Spill Prevention, Control, and Countermeasure Plans in connection with on-site storage of significant quantities of oil.

Our oil and natural gas production also generates salt water, which we dispose of by underground injection. The federal Safe Drinking Water Act ("SDWA"), the Underground Injection Control ("UIC") regulations promulgated under the SDWA and related state programs regulate the drilling and operation of salt water disposal wells. The EPA directly administers the UIC program in some states, and in others it is delegated to the state for administering. Permits must be obtained before drilling salt water disposal wells, and casing integrity monitoring must be conducted periodically to ensure the casing is not leaking salt water to groundwater. Contamination of groundwater by oil and natural gas drilling, production, and related operations may result in fines, penalties, and remediation costs, among other sanctions and liabilities under the SDWA and state laws. In addition, third party claims may be filed by landowners and other parties claiming damages for alternative water supplies, property damages, and bodily injury.

Hydraulic Fracturing

The completion operations of wells we participate in are subject to regulation, which may increase in the short- or long-term. The well completion technique known as hydraulic fracturing is used to stimulate production of natural gas and oil has come under increased scrutiny by the environmental community, and local, state and federal jurisdictions. Hydraulic fracturing involves the injection of water, sand and additives under pressure, usually down casing that is cemented in the wellbore, into prospective rock formations at depth to stimulate oil and natural gas production.

Under the direction of Congress, the EPA has undertaken a study of the effect of hydraulic fracturing on drinking water and groundwater. The EPA has also announced its plan to propose pre-treatment standards under the Clean Water Act for wastewater discharges from shale hydraulic fracturing operations. Congress may consider legislation to amend the SDWA to require the disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Certain states, including Colorado and Wyoming, have issued similar disclosure rules. Several environmental groups have also petitioned the EPA to extend toxic release reporting requirements under the Emergency Planning and Community Right-to-Know Act to the oil and natural gas extraction industry. Additional disclosure requirements could result in increased regulation, operational delays, and increased operating costs that could make it more difficult to perform hydraulic fracturing.

Air Emissions

The federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through permitting programs and the imposition of other requirements. In addition, the EPA has developed and continues to develop stringent regulations governing emissions of toxic air pollutants at specified sources, including oil and natural gas production. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the federal Clean Air Act and associated state laws and regulations. Our operations, or the operations of service companies engaged by us, may in certain circumstances and locations be subject to permits and restrictions under these statutes for emissions of air pollutants.

Recently, the EPA issued four new regulations for the oil and natural gas industry, including: a new source performance standard for volatile organic compounds (“VOCs”); a new source performance standard for sulfur dioxide; an air toxics standard for oil and natural gas production; and an air toxics standard for natural gas transmission and storage. The final rule includes the first federal air standards for natural gas wells that are hydraulically fractured, or refractured, as well as requirements for several sources, such as storage tanks and other equipment, and limits methane emissions from these sources. Compliance with these regulations will impose additional requirements and costs on our operations.

In December 2014, the EPA proposed to lower the existing 75 parts per billion (“ppb”) national ambient air quality standards (“NAAQS”) for ozone under the federal Clean Air Act to a range within 65-70 ppb. The EPA is also taking public comment on whether the ozone NAAQS should be revised to as low as 60 ppb. A lowered ozone NAAQS in a range of 60-70 ppb could result in a significant expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and natural gas operations in ozone nonattainment areas would likely be subject to increased regulatory burdens in the form of more stringent emission controls, emission offset requirements, and increased permitting delays and costs.

Climate Change

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth’s atmosphere. In response to these studies, governments have begun adopting domestic and international climate change regulations that require reporting and reductions of the emission of such greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries including those comprising the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the emission inventories, emissions targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the EPA has issued regulations requiring us and other companies to annually report certain greenhouse gas emissions from our oil and natural gas facilities. Beyond its measuring and reporting rules, the EPA has issued an “Endangerment Finding” under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities.

In addition, President Obama released a Strategy to Reduce Methane Emissions in March 2014. Consistent with that strategy, the EPA has announced that it intends to issue a proposed rule in 2015 to set standards for methane and VOC emissions from new and modified oil and natural gas production sources and natural gas processing and transmission sources. The EPA intends to issue a final rule in 2016. As another prong of the President’s strategy, the federal Bureau of Land Management (“BLM”) is expected to propose standards in 2015 to reduce venting and flaring on public lands. The EPA and BLM actions are part of a series of steps by the Administration that are intended to result by 2025 in a 40-45% decrease in methane emissions from the oil and natural gas industry as compared to 2012 levels. In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions control systems or other compliance costs, and reduce demand for our products.

The National Environmental Policy Act

Oil and natural gas exploration and production activities may be subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of the Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. This process has the potential to delay the development of future oil and natural gas projects.

Threatened and endangered species, migratory birds and natural resources

Various state and federal statutes prohibit certain actions that adversely affect endangered or threatened species and their habitat, migratory birds, wetlands, and natural resources. These statutes include the Endangered Species Act, the Migratory Bird Treaty Act, the Clean Water Act and CERCLA. The United States Fish and Wildlife Service may designate critical habitat areas that it believes are necessary for survival of threatened or endangered species. A critical habitat designation could result in further material restrictions on federal land use or on private land use and could delay or prohibit land access or development. Where takings of or harm to species or damages to wetlands, habitat, or natural resources occur or may occur, government entities or at times private parties may act to prevent or restrict oil and natural gas exploration activities or seek damages for any injury, whether resulting from drilling or construction or releases of oil, wastes, hazardous substances or other regulated materials, and in some cases, criminal penalties.

Hazard communications and community right to know

We are subject to federal and state hazard communication and community right to know statutes and regulations. These regulations govern record keeping and reporting of the use and release of hazardous substances, including, but not limited to, the federal Emergency Planning and Community Right-to-Know Act and may require that information be provided to state and local government authorities and the public.

Occupational Safety and Health Act

We are subject to the requirements of the federal Occupations Safety and Health Act and comparable state statues that regulate the protection of the health and safety of workers. In addition, the Occupational Safety and Health Administration’s hazard communication standard requires that information be maintained about hazardous materials used or produced in operations and that this information be provided to employees.

Employees

We currently have no full time or part time employees. Our officers serve us in a consulting capacity. We anticipate adding employees and are currently using independent contractors, consultants, attorneys and accountants as necessary, to complement services for operations and regulatory filings.

Intellectual Property

We do not currently have any patents, trademarks or licenses.

Item 1A. RISK FACTORS

An investment in our common stock involves a high degree of risk. Readers of this report should consider carefully the following risks, along with all of the other information included in this report. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may also impair our business operations. If we are unable to prevent events that have a negative effect from occurring, then our business may suffer. Some of the information in this Annual Report on Form 10-K contains forward-looking statements that involve substantial risks and uncertainties. These statements can be identified by forward-looking words such as “may,” “will,” “expect,” “anticipate,” “believe,” “intend,” “estimate,” and “continue” or other similar words. Statements that contain these words should be carefully read for the following reasons:

- *The statements may disclose our future expectations;*

- *The statements may contain projections of our future earnings or our future financial condition; and*
- *The statements may state other "forward-looking" information.*

Risks Related to Our Business and Industry

We will require significant additional capital in seeking to execute our business plan, which may not be available or may only be available on unfavorable terms.

Our future capital requirements depend on many factors, including development and acquisition opportunities, the availability of debt financing and the cash flow from our operations. To the extent that the funds available are insufficient to meet future capital requirements, we will likely need to reduce our development activity as we did in 2014. Any equity or debt financing, if available at all, may be on terms that are not favorable to us. If we cannot obtain adequate capital on favorable terms or at all, our business, operating results and financial condition will likely be adversely affected.

Volatile oil and natural gas prices could adversely affect our financial condition and results of operations.

Our most significant market risk is the price of crude oil and natural gas. Management expects energy prices to remain volatile and unpredictable. Moreover, oil and natural gas prices result from numerous factors that are outside of our control, including:

- Economic and energy infrastructure disruptions caused by geopolitical factors including but not limited to embargoes and sanctions on major producing countries and actual or threatened acts of war, or terrorist activities particularly with respect to oil producers in the Middle East, Nigeria and Venezuela;
- Weather conditions, such as hurricanes, including energy infrastructure disruptions resulting from those conditions;
- Changes in the global oil supply, demand and inventories;
- Changes in domestic natural gas supply, demand and inventories;
- The price and quantity of foreign imports of oil;
- Political conditions in or affecting other oil-producing countries;
- General economic conditions in the United Stated and worldwide;
- The level of worldwide oil and natural gas exploration and production activity;
- Technological advances affecting energy consumption; and
- The price and availability of alternative fuels.

Lower oil and natural gas prices not only decrease revenues on a per unit of production basis, but also may reduce the amount of oil and natural gas that we can economically produce negatively impacting estimates of our economically recoverable proved reserves. Substantial or extended declines in oil or natural gas prices may materially and adversely affect our financial condition, results of operations, liquidity and ability to finance operations and planned capital expenditures.

A drastic reduction in crude oil prices and related products from nearly $100 per barrel at mid-year 2014 to as low as $45 per barrel in early 2015 has impacted the oil and gas industry. As of April 13, 2015, the price of crude oil was approximately $51 per barrel. Should the recent prevailing oil prices remain in effect for an extended period of time, we may be required to curtail capital expenditures unless we are able to raise additional equity or debt funding. Continuation of the steep decline in oil prices, and any declines that may occur in the future, can be expected to significantly reduce our revenues, profitability and cash flow as well as the value of our reserves and may also adversely affect the economics of future operations resulting in deferral or cancellation of planned drilling and related activities until such time, if ever, as economic conditions improve sufficiently to support such operations.

If oil and natural gas prices decrease, we may be required to negatively impacting the trading value of our securities.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we have and may be required to further write down the carrying value of our oil and natural gas properties. A write-down would constitute a non-cash charge to earnings. It is likely the cumulative effect of a write-down could also negatively impact the trading price of our securities.

We do not have any employees and we depend on our chief executive officer and chief financial officer for a significant majority of our management decisions, operations and industry contacts.

Due to our limited operations, we do not have any employees, and our executive officers are retained as independent contractors on a part-time basis. We are heavily dependent upon the efforts of our Chief Executive Officer, Nicholas L. Scheidt, who essentially operates our company and our Chief Financial Officer, Donald W. Prosser, who handles the finances and financial filings. We do not have an employment agreement with either officer nor do we have any key man insurance on their life. As we currently do not have a successor to Messrs. Scheidt and Prosser, the loss of either of their services would likely have a material adverse impact on our business.

Our future performance is difficult to evaluate because we have a limited operating history.

Our operations in the natural resources industry commenced with our acquisition of a gas gathering pipeline as of September 2006. In the third quarter of 2011, we purchased various oil and gas producing properties for a base purchase price of $11,000,000. Prior to our third quarter of 2011 asset acquisition, our revenues were minimal and we incurred significant losses. As of December 31, 2014, our accumulated deficit was approximately $16.2 million.

Oil and gas prices must remain at sufficient levels in order for us to operate profitably.

In the event we are able to raise substantial additional capital, we expect to focus on acquiring oil and gas properties that we believe offer profit potential from overlooked and by-passed reserves of oil and natural gas, which will include shut-in wells, in-field development, stripper wells, re-completion and re-working projects. Because production is generally on a decline on these mature properties while operating expenses can be high, declines in oil and gas prices will likely have a greater negative impact on our operations compared to oil and gas companies that focus on newer developed properties.

We may expend substantial funds in acquiring and redeveloping properties which are later determined to not be economically viable.

The search for new oil and gas reserves, development wells or secondary recovery frequently result in unprofitable efforts, not only from dry holes, but also from wells which, though productive, will not produce oil or gas in sufficient quantities to return a profit on the costs incurred. There is no assurance that any production will be obtained from any of the acreage to be acquired by us, nor are there any assurances that if such production is obtained, it will be profitable. We may expend substantial funds in acquiring and redeveloping properties which are later determined not to be economically viable. All funds so expended may be a total loss to us and which could result in possibly significant impairments in our oil and gas asset base. In such event, our profitability and operations may be materially adversely affected.

The domestic oil and gas exploration and production industry is faced with shortages of personnel and equipment, and such shortages may adversely affect our operations and financial results.

The oil and gas industry, as a whole, suffers from an aging workforce and a shortage of qualified and experienced personnel. Our operations and financial results may be adversely impacted due to difficulties in attracting and retaining such personnel within our Company or within companies that provide materials and services to the industry. The substantial increase in oil prices in 2011 resulted in increased drilling and construction activity in the industry and shortages of personnel and equipment are present in our primary focus areas. Further, our plans will likely require access to services and oil field equipment. Such equipment and operating personnel are currently in short supply.

Restrictions in any future credit agreements may prevent us from engaging in some beneficial transactions.

We are seeking to enter into credit agreements with financial institutions to fund a portion of our anticipated capital requirements. To obtain funds under credit agreements we may be required to accept operating restrictions which would impair or prevent us from future transactions we deem to be beneficial to us.

Competition for experienced technical personnel may negatively impact our operations.

Our acquisition strategy's success could depend, in part, on our ability to attract and retain experienced professional personnel. The loss of any key executives or other key personnel could have a material adverse effect on our operations. The scope of our operations and our future will depend on our ability to attract and retain qualified personnel, particularly individuals with a strong background in geology, geophysics, engineering and operations.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our financial condition and results of operations.

Our success depends on the results of our exploitation, exploration, development and production activities. Oil and natural gas exploration and production activities are subject to numerous significant risks some of which are beyond our control; including the risk that drilling will not result in commercially viable oil or natural gas production. Decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in large part on our proper evaluation and assessment of data obtained through geophysical and geological analyses, production data, and engineering studies. Our evaluations and assessments could ultimately prove to be incorrect. Significant aspects of costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can render a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including:

- Shortages of or delays in obtaining equipment and qualified personnel such as we are currently experiencing;
- Pressure or irregularities in geological formations;
- Equipment failures or accidents;
- Adverse weather conditions;
- Reductions in oil and natural gas prices;
- Issues associated with property titles; and
- Delays imposed by or resulting from compliance with regulatory requirements.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

Oil and natural gas exploration, drilling and production activities are subject to numerous operating risks including the possibility of:

- Blowouts, fires and explosions;
- Personal injuries and death;
- Uninsured or underinsured losses;
- Unanticipated, abnormally pressured formations;
- Mechanical difficulties, such as stuck oil field drilling and service tools and casing collapses; and
- Environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination.

Any of these operating hazards could cause damage to properties, serious injuries, fatalities, oil spills, discharge of hazardous materials, remediation and clean-up costs, and other environmental damages, which could expose us to significant liabilities.

Seeking to grow our business by purchase of production, expanding existing production, and exploration subjects us to development and other risks.

The search for commercial quantities of oil and natural gas as a business is highly risky. We cannot provide investors with any assurance that any properties in which we obtain a mineral interest will contain commercially exploitable quantities of oil and/or gas. The exploration expenditures to be made by us may not result in the discovery of commercial quantities of oil and/or gas. Problems such as unusual or unexpected formations or pressures, premature declines of reservoirs, invasion of water into producing formations and other conditions involved in oil and gas exploration often result in unsuccessful exploration efforts. If we are unable to find commercially exploitable quantities of oil and gas, and/or we are unable to commercially extract such quantities, we may be forced to abandon or curtail our business plan, and as a result, any investment in us may become worthless.

Future oil and gas price declines or unsuccessful exploration efforts may result in write-downs of our exploration and production asset carrying values.

We follow the successful efforts method of accounting for our oil and gas properties. All property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending the determination of whether proved reserves have been discovered. If proved reserves are not discovered with an exploratory well, the costs of drilling the well are expensed. The capitalized costs of our oil and gas properties, on a field basis, cannot exceed the estimated future net cash flows of that field. If net capitalized costs exceed future net revenues, we must write down the costs of each such field to our estimate of fair market value. Unproved properties are evaluated at the lower of cost or fair market value. Accordingly, a significant decline in oil or gas prices or unsuccessful exploration efforts could cause a future write-down of capitalized costs.

We review the carrying value of our proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The impairment analysis is based on then current oil and gas prices in effect. Once incurred, a write-down of oil and gas properties cannot be reversed at a later date even if oil or gas prices increase.

Future oil and gas price declines may affect our ability to raise capital.

If oil and gas prices decrease there will be a corresponding negative impact on the value of our reserves. This could negatively affect our ability to borrow funds or raise equity capital.

Competition in our industry is intense, and many of our competitors have greater financial and technical resources than we do.

We face intense competition from major oil companies, independent oil and gas exploration and production companies, financial buyers and institutional and individual investors who are actively seeking oil and gas properties, along with the equipment, expertise, labor and materials required to operate oil and gas properties. Many of our competitors have financial and technical resources vastly exceeding those available to us, and many oil and gas properties are sold in a competitive bidding process in which our competitors may be able to pay more for development prospects and productive properties or in which our competitors have technological information or expertise to evaluate and successfully bid for the properties that is not available to us. In addition, shortages of equipment, labor or materials as a result of intense competition may result in increased costs or the inability to obtain those resources as needed. We may not be successful in acquiring and developing profitable properties in the face of this competition.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud.

Our internal controls and operations are subject to extensive regulation and reporting obligations and as of December 31, 2014, we concluded that our disclosure controls and procedures were not effective. See Item 9A, “Controls and Procedures”. A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, effective internal control over financial reporting may not prevent or detect misstatements. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet certain reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our shares of common stock.

If we learn of any title defects on the properties we own or acquire, it could have a material adverse effect on our operations and profitability.

We may not be the record owner of interest in our properties and may rely instead on contracts with the owner or operator of the property or assignment of leases, pursuant to which, among other things, we have the right to have our interest placed of record. As is customary in the oil and gas industry, a preliminary title examination will be conducted at the time properties or interests are acquired by us. Prior to commencement of operations on such acreage and prior to the acquisition of properties, a title examination will usually be conducted and significant defects remedied before proceeding with operations or the acquisition of proved properties, as appropriate.

Our producing properties are subject to royalty, overriding royalty and other interests customary in the industry, liens incident to agreements, current taxes and other burdens, minor encumbrances, easements and restrictions. Although we are not aware of any material title defects or disputes with respect to our current and prospective acreage acquisitions, to the extent such defects or disputes exist, we could suffer title failures.

Our officers and directors are engaged in other business activities and conflicts of interest have arisen in their daily activities which may not be resolved in our favor.

Certain conflicts of interest exist between us and our officers and directors. Officers or directors may bring energy prospects to us in which they have an interest. They have other business interests to which they devote their attention, and will be expected to continue to do so. They will also devote management time to our business. As a result, conflicts of interest or potential conflicts of interest may arise from time to time that can be resolved only through the officers and directors exercising such judgment as is consistent with fiduciary duties to their other business interests and to us. See Item 13, “Certain Relationships and Related Transactions, and Director Independence”.

Insurance may not fully recover potential losses.

Although we believe that we are reasonably insured against losses to wells and associated equipment, potential operational related losses could result in a loss of our reserves and properties and materially reduce our ability to self-fund exploration and development activities and property acquisitions. The insurance market, in general, and the energy insurance market in particular, have experienced substantial cost increases over recent years, resulting from significant losses associated with commercial losses. The potential for loss, however, cannot be accurately or reasonably predicted. If we incur substantial damages or liabilities that are not fully covered by insurance or are in excess of policy limits, then our business, results of operations, and financial condition could be materially affected. Also, as is customary in the oil and gas business, we do not carry business interruption insurance. In the future, it is also possible that we will further modify insurance coverage or determine not to purchase some insurance because of high insurance premiums.

Our failure to successfully identify, complete and integrate future acquisitions of properties or businesses could reduce any earnings we may achieve.

There is intense competition for acquisition opportunities in our industry for attractive oil and gas properties and other exploration and production. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our ability to complete acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Completed acquisitions could require us to invest further in operational, financial and management information systems and to attract, retain, motivate and manage effectively additional employees. The inability to effectively manage the integration of acquisitions could reduce our focus on subsequent acquisitions and current operations, which, in turn, could negatively impact our earnings and growth. Our financial position and results of operations may fluctuate significantly from period to period, based on whether or not significant acquisitions are completed in particular periods.

Negative or downward revisions of oil and gas reserve estimates could adversely affect the trading price of our common stock. Oil and gas reserves and the standardized measure of cash flows represent estimates, which may vary materially over time due to many factors.

The market price of our common stock may be subject to significant decreases due to decreases in our estimated reserves, our estimated cash flows and other factors. Estimated reserves may be subject to downward revision based upon future production, results of future development, prevailing oil and gas prices, prevailing operating and development costs, SEC rules related to proved undeveloped reserves and other factors. There are numerous uncertainties and uncontrollable factors inherent in estimating quantities of oil and gas reserves, projecting future rates of production, and timing of development expenditures.

The estimates of future net cash flows from proved reserves and the standardized measure of proved reserves are based upon various assumptions about prices and costs and future production levels that may prove to be incorrect over time. Any significant variance from the assumptions could result in material differences in the actual quantity of reserves and amount of estimated future net cash flows from estimated oil and gas reserves.

In addition, SEC rules generally require that proved undeveloped reserves that have not been drilled within five years be reclassified out of estimates of proved reserves; although such technically and economically recoverable reserves may be still owned or controlled by us. Accordingly, given the shortages of materials, equipment and human resources prevailing in the industry and also current low natural gas prices we may not drill certain proved undeveloped locations within the established five year time frame and therefore we may be required to reclassify such reserves out of our estimated proved undeveloped reserves. The effect of reclassifying such reserves would result in decreases in estimated proved reserve quantities and therefore could result in decreases in net income and earnings per share, resulting from increased depletion expense and possible impairments. These effects could have an adverse effect on our stock price.

Our properties are subject to influence by other parties that do not allow us to proceed with exploration and expenditures as we may desire.

We do not operate any of our properties. Joint ownership is customary in the oil and gas industry and is generally conducted under the terms of a joint operating agreement ("JOA"), where a single working interest owner is designated as the "operator" of the property. All of our producing oil and gas properties are operated by DNR, an affiliate of one of our officers and directors, Charles Davis. Thus, drilling and operating decisions are not within our sole control. If we disagree with the decision of this operator, we may be required, among other things, to postpone the proposed activity or decline to participate. If we decline to participate, we might be forced to relinquish our interest through "in-or-out" elections or may be subject to certain non-consent penalties, as provided in a JOA. In-or-out elections may require a joint owner to participate, or forever relinquish its position. Non-consent penalties typically allow participating working interest owners to recover from the proceeds of production, if any, and an amount equal to 200% to 500% of the non-participating working interest owner's share of the cost of such operations.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated or curtailed as a result of future legislation.

Among the changes contained in the Obama Administration's Fiscal Year 2013 budget proposal, released by the Office of Management and Budget, is the elimination or deferral of certain U.S. federal income tax deductions and credits currently available to domestic oil and gas exploration companies. Such changes include, but are not limited to, (i) the elimination of current deductions for intangible drilling and development costs; (ii) the elimination of the deduction for certain U.S. production activities for oil and gas properties; (iii) an extension of the amortization period for certain geological and geophysical expenditures and (iv) the repeal of the enhanced oil recovery credit. Some of these same proposals to repeal or limit oil and gas tax deductions and credits have been included in legislation that has recently been considered by Congress. It is unclear whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation as a result of the budget proposal, or the passage of bills containing similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions and credits that are currently available with respect to oil and gas exploration and development and could negatively affect our financial results.

The nature of our business and assets may expose us to significant compliance costs and liabilities.

Our operations involving the exploration, production, storage, treatment, and transportation of liquid hydrocarbons, including crude oil, are subject to stringent federal, state, and local laws and regulations governing the discharge of materials into the environment. Our operations are also subject to laws and regulations relating to protection of the environment, operational safety, and related employee health and safety matters. Compliance with all of these laws and regulations may represent a significant cost of doing business. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties; the imposition of investigatory and remedial liabilities; and the issuance of injunctions that may restrict, inhibit or prohibit our operations; or claims of damages to property or persons.

Compliance with environmental laws and regulations may require us to spend significant resources.

Environmental laws and regulations may: (1) require the acquisition of a permit before well drilling commences; (2) restrict or prohibit the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities; (3) prohibit or limit drilling activities on certain lands lying within wetlands or other protected areas; and (4) impose substantial liabilities for pollution resulting from past or present drilling and production operations. Moreover, changes in Federal and state environmental laws and regulations, as well as how such laws and regulations are administered, could occur and may result in more stringent and costly requirements which could have a significant impact on our operating costs. In general, under various applicable environmental regulations, we may be subject to enforcement action in the form of injunctions, cease and desist orders and administrative, civil and criminal penalties for violations of environmental laws. We may also be subject to liability from third parties for civil claims by affected neighbors arising out of a pollution event. Laws and regulations protecting the environment may, in certain circumstances, impose strict liability rendering a person liable for environmental damage without regard to negligence or fault on the part of such person. Such laws and regulations may expose us to liability for the conduct of or conditions caused by others, or for our acts which were in compliance with all applicable laws at the time such acts were performed. We believe we are in compliance with applicable environmental and other governmental laws and regulations. In recent years, increased concerns have been raised over the protection of the environment. Legislation to regulate the emissions of greenhouse gases has been introduced in Congress, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. In addition, efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. Also, the EPA has recently undertaken significant efforts to collect information regarding greenhouse gas emissions and their effects.

Climate change legislation or regulations restricting emissions of "greenhouse gasses" could result in increased operating costs and reduced demand for crude oil and natural gas that we produce.

In December 2009, the U.S. Environmental Protection Agency, ("EPA") determined that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs"), present an endangerment to public health and the environment because emissions of such gasses are, according to the EPA, contributing to the warming of the earth's atmosphere and other climate changes. Based on these findings the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of rules regulating greenhouse gas emissions under the Clean Air Act, one set of rules limit emissions of GHGs from motor vehicles and the other set of rules require certain Prevention of Significant Deterioration ("PSD") and Title V permit requirements for GHG emissions from certain large stationary sources. The EPA rules have tailored the PSD and Title V permitting programs to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States, including, among others, certain oil and natural gas production facilities, which may include certain of our operations, on an annual basis.

In addition, the U.S. Congress has from time to time considered legislation to reduce emissions of GHGs, and almost one-half of the states have already taken legal measures to reduce emissions of GHGs, primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of any legislation or regulations that requires reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce.

Federal, state, and local legislative and regulatory initiatives relating to hydraulic fracturing, as well as government reviews of such activities, could result in increased costs, additional operating restrictions or delays, and adversely affect our production and/or ability to book future reserves.

Hydraulic fracturing involves the injection of water, sand, and chemical additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA, recently asserted federal regulatory authority over certain hydraulic-fracturing activities involving diesel under the Safe Drinking Water Act and has begun the process of drafting guidance documents related to this newly asserted regulatory authority. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In February 2012, the U.S. Department of the Interior (the “DOI”) released draft regulations governing hydraulic fracturing on federal and Indian oil and gas leases to require disclosure of information regarding the chemicals used in hydraulic fracturing, advance approval for well-stimulation activities, mechanical integrity testing of casing, and monitoring of well-stimulation operations. In addition, the U.S. Congress, from time to time, has considered adopting legislation intended to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. In the event that a new, federal level of legal restrictions relating to the hydraulic-fracturing process are adopted in areas where we currently or in the future plan to operate, we may incur additional costs to comply with such federal requirements that may be significant in nature, and also could become subject to additional permitting requirements and cause us to experience added delays or curtailment in the pursuit of exploration, development, or production activities.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices, and a committee of the U.S. House of Representatives has conducted an investigation of hydraulic-fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected to be available by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic-fracturing activities and plans to propose these standards by 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. These ongoing or proposed studies, depending on any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

In addition, some states have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. For example, Colorado, Montana, Pennsylvania, Louisiana, Texas, and Wyoming, have adopted, and other states are considering adopting, regulations that could impose new or more stringent permitting, disclosure, and additional well-construction requirements on hydraulic-fracturing operations. For example, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general and/or hydraulic fracturing in particular. These regulations will affect our operations, increase our costs of exploration and production and limit the quantity of natural gas and oil that we can economically produce to the extent that we use hydraulic fracturing. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities on a timely basis following leasing. Delays in obtaining regulatory approvals, drilling permits, the failure to obtain a drilling permit for a well or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore on or develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase our financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff.

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors, customers and by counterparties to our hedging arrangements. Some of our vendors, customers and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors, customers and counterparties finance their activities through cash flow from operations, the use of debt or the issuance of equity. Even if our credit reviews are satisfactory, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors, customers and/or counterparties could adversely affect our financial condition and results of operation.

Risks Related to Our Common Stock

Investors may be diluted in future Common Stock offerings.

The holders of our common stock have no preemptive rights, and the issuance of additional shares of common stock by us may result in a commensurate reduction in an individual shareholder's percentage ownership in us. The value of an investor's investment in our convertible preferred stock may decrease to the extent that such dilution reduces the fair value of the shares of common stock.

Our common stock is thinly traded and our share price has fluctuated in the past and may continue to fluctuate in the future.

Our common stock has historically been thinly traded and the market price of our common shares in the over-the-counter market has experienced significant volatility and may continue to fluctuate significantly. The market price of our common shares may be significantly affected by factors such as the announcements of agreements and technological innovations by us or our competitors. In addition, while we cannot assure you that any securities analysts will initiate or maintain research coverage of our company and our shares, any statements or changes in estimates by analysts initiating or covering our shares or relating to the oil and gas industry could result in an immediate and adverse effect on the market price of our shares. Further, we cannot predict the effect, if any, that market sales of shares or the availability of shares for sale will have on the market price of the shares prevailing from time to time. Issuance and sale of a substantial number of shares or the perception that such sales could occur, could have a material adverse effect on the market price of our shares.

Trading in shares of companies, such as ours, have been subject to extreme price and volume fluctuations that have been unrelated or disproportionate to operating or other performance.

Trading on the OTC Market may be volatile and sporadic, which could depress the market price of our common stock and make it difficult for our shareholders to resell their shares.

Our common stock is quoted on the OTC Market. Trading in stock quoted on the OTC Bulletin Board is often thin and characterized by wide fluctuations in trading prices due to many factors that may have little to do with our operations or business prospects. This volatility could depress the market price of our common stock for reasons unrelated to operating performance. Moreover, the OTC Market is not a stock exchange, and trading of securities on the OTC Market is often more sporadic than the trading of securities listed on other stock exchanges such as the NASDAQ Stock Market, New York Stock Exchange or American Stock Exchange. Accordingly, our shareholders may have difficulty reselling any of their shares.

Our common stock is a penny stock. Trading of our stock may be restricted by the SEC's penny stock regulations and the FINRA's sales practice requirements, which may limit a shareholders ability to buy and sell our stock.

Our common stock is a penny stock. The SEC has adopted Rule 15g-9 which generally defines penny stock to be any equity security that has a market price (as defined) less than $5.00 per share or an exercise price of less than $5.00 per share, subject to certain exceptions. Our securities are covered by the penny stock rules, which impose additional sales practice requirements on broker-dealers who sell to persons other than established customers and accredited investors. The term accredited investor refers generally to institutions with assets in excess of $5,000,000 or individuals with a net worth in excess of $1,000,000 or annual income exceeding $200,000 or $300,000 jointly with their spouse. The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from the rules, to deliver a standardized risk disclosure document in a form prepared by the SEC which provides information about penny stocks and the nature and level of risks in the penny stock market. The broker-dealer must also provide the customer with current bid and offer quotations for the penny stock, the compensation of the broker-dealer and its salesperson in the transaction and monthly account statements showing the market value of each penny stock held in the customer's account. The bid and offer quotations, and the broker-dealer and salesperson compensation information, must be given to the customer orally or in writing prior to effecting the transaction and must be given to the customer in writing before or with the customer's confirmation. In addition, the penny stock rules require that prior to a transaction in a penny stock not otherwise exempt from these rules, the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser's written agreement to the transaction. These disclosure requirements may have the effect of reducing the level of trading activity in the secondary market for the stock that is subject to these penny stock rules. Consequently, these penny stock rules may affect the ability or willingness of broker-dealers to trade our securities. We believe that the penny stock rules discourage broker-dealer and investor interest in, and limit the marketability of, our common stock.

FINRA sales practice requirements may also limit a shareholders ability to buy and sell our stock.

In addition to the penny stock rules promulgated by the SEC, which are discussed in the immediately preceding risk factor, FINRA rules require that in recommending an investment to a customer, a broker-dealer must have reasonable grounds for believing that the investment is suitable for that customer. Prior to recommending speculative low priced securities to their non-institutional customers, broker-dealers must make reasonable efforts to obtain information about the customer's financial status, tax status, investment objectives and other information. Under interpretations of these rules, FINRA believes that there is a high probability that speculative low priced securities will not be suitable for at least some customers. FINRA requirements make it more difficult for broker-dealers to recommend that their customers buy our common stock, which may limit the ability to buy and sell our stock and have an adverse effect on the market value for our shares.

There are a substantial number of shares of our common stock eligible for future sale in the public market. The sale of a large number of these shares could cause the market price of our common stock to fall.

There were 12,558,459 shares of our common stock outstanding as of April 14, 2015. As of that date, members of our management and their affiliates beneficially owned approximately 5,299,818 shares of our common stock, representing 42.19% of our outstanding common stock. Sale of a substantial number of these shares would likely have a significant negative effect on the market price of our common stock, particularly if the sales are made over a short period of time.

If our shareholders, particularly management and their affiliates, sell a large number of shares of our common stock, the market price of shares of our common stock could decline significantly. Moreover, the perception in the public market that our management and affiliates might sell shares of our common stock could depress the market price of those shares.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We have never declared or paid cash dividends on our common stock. We currently intent to retain all future earnings and other cash resources, if any, for the operations and development of our business and do not anticipate paying cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansions. In addition, we may not pay cash dividends on our common stock for so long as any shares of our convertible preferred stock are outstanding. Any future dividends may also be restricted by any loan agreements which we may enter into from time to time and from the issuance of preferred stock should we decide to do so in the future.

Access to Information

Our website address is www.areteindustries.com We make available, free of charge, on the "Filings" section of our website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to those reports, as soon as reasonably practicable after these reports are electronically filed with or furnished to the Securities and Exchange Commission ("SEC"). We also make available through our website other reports electronically filed with the SEC under the Securities Exchange Act of 1934, including our proxy statements. We do not intend for information contained in our website to be part of this Annual Report on Form 10-K.

Item 1B. UNRESOLVED STAFF COMMENTS

None

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Item 2. PROPERTIES

Oil and Natural Gas Properties

The following table lists our oil and natural gas properties by state and field as of December 31, 2014:

Field	County	Productive Wells Gross	Productive Wells Net *(a)*	Proved Reserves (BOE) *(b)*
Wyoming:				
Rex Lake	Albany	7.0	7.0	14,092
Buff	Campbell	4.0	4.0	35,151
Shippy	Campbell	1.0	1.0	21,596
Bobcat Creek	Converse	1.0	0.6	4,902
Other	Various	19.0	8.4	45,492
Kansas:				
Big Bow	Stanton	5.0	1.5	32,034
Granger Creek	Clark	1.0	1.0	47,510
Walz	Trego	1.0	0.9	25,323
Other	Graham	1.0	0.9	8,382
Colorado:				
Gemini	Weld	2.0	2.0	47,287
Smokey Creek	Cheyenne	1.0	0.7	31,628
Wild Horse	Weld	1.0	1.0	2,525
Other	Various	3.0	3.0	10,936
Montana:				
Police Coulee	Toole	2.0	1.4	6,163
		49.0	33.4	333,021

(a) Net wells are the sum of our fractional working interests owned in gross wells.
(b) BOE is defined as one barrel of oil equivalent determined using the ratio of six Mcf of natural gas to one barrel of oil.

Gas Gathering System

In September 2006, the Company acquired a gas gathering system (pipeline and compressor station related assets) located in Campbell County, Wyoming. This system was constructed in late 2001 and began operations early in 2002. The system consists of 4.5 miles of 8-inch coated steel pipeline. This pipeline has been shut-in since June 2011 and is not generating revenue. The system has been shut in due to the low price of natural gas.

This system has a current throughput capacity of approximately 4 million cubic feet ("MMcf") of gas per day. Since July 2011, the Company has owned a 100% working interest in all of the coal-bed methane properties that are connected to the Company's gathering system.

Description of Coal-Bed Methane Properties - Powder River Basin Geology

In December 1994, there were approximately 200 wells in the Powder River Basin producing coal-bed methane gas. Since 1994, over 15,000 gas wells have been drilled in this area and the State of Wyoming and the Bureau of Land Management ("BLM") have the authority to grant over 15,000 additional drilling permits. Production in 1994 was 2.4 billion cubic feet, and production in 2003 was 3.46 billion cubic feet (Source: Wyoming Oil and Gas Conservation Commission). The average well-life of coal-bed methane well is estimated by the BLM to be eight to ten years.

Gas produced from Powder River Basin coals is almost 100% methane. The gas is generated during the coal forming process and is trapped in the coal beds by water. In order to produce the coal gas, the formation must first be dewatered. As the water is removed from the coal, the gas is desorbed from the coal. All of the coal-bed reservoirs are low pressure and require compression in order for the gas to be delivered to a pipeline transportation system.

Natural gas wells in the Powder River Basin area typically experience sharp declines in production volume in the first several years of production. Production then stabilizes and declines more ratably over a gas well's average life of approximately eight to ten years. Other factors which influence the initial and long term productivity of the coal-bed methane wells are the depths of the coal fields, the initial gas saturation levels of the coal field and the well spacing.

Office Facilities

We currently lease our office space in Westminster, Colorado for $250 per month from our Chief Financial Officer.

Item 3. LEGAL PROCEEDINGS

None

Item 4. MINE SAFETY DISCLOSURES

Not Applicable.

PART II

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

Our common stock has been quoted on the OTCQB tier of the OTC Markets. Our trading symbol is "ARET.OTCQB"

The following table sets forth the range of high and low trading price information for our common stock for each fiscal quarter for the past two fiscal years as reported by the OTC Markets Inc. and obtained from Yahoo Finance. High and low trading information represents prices between dealers without adjustment for retail mark-ups, markdowns or commissions.

	HIGH	LOW
Year Ended December 31, 2014:		
First Quarter	$0.89	$ 0.22
Second Quarter	0.45	0.26
Third Quarter	0.43	0.20
Fourth Quarter	0.27	0.08
Year Ended December 31, 2013:		
First Quarter	$0.45	$0 .25
Second Quarter	0.35	0.16
Third Quarter	0.45	0.16
Fourth Quarter	0.40	0.34

On April 14, 2015, the last reported sales price of our common stock as reported on the OTCQB was approximately $.13 per share.

Holders

As of April 14, 2015, the approximate number of holders of record of shares of our common stock, our only class of trading securities, was approximately 3,900. The number of record holders of our common stock was determined from the records of our transfer agent and does not include numerous beneficial owners of our common stock whose shares are held in street name by various security brokers, dealers, and registered clearing agencies. The number of beneficial shareholders is unknown to us.

Dividends

The Company has not paid any cash dividends with respect to its common stock and it is not anticipated that the Company will pay cash dividends in the foreseeable future. Also, the Company cannot pay cash dividends on its common stock so long as any shares of convertible preferred stock are outstanding. During 2014 the Company cancelled the balance of its preferred stock shares outstanding. The Company as part of it's line of credit agreement most ask the bank for permission to pay a cash dividend.

The Securities Enforcement and Penny Stock Reform Act of 1990

The SEC has adopted rules that regulate broker-dealer practices in connection with transactions in penny stocks. Penny stocks are generally equity securities with a price of less than $5.00 (other than securities registered on certain national securities exchanges or quoted on the Nasdaq system, provided that current price and volume information with respect to transactions in such securities is provided by the exchange or system). Our common shares are currently subject to the penny stock rules.

A purchaser purchasing a penny stock has limitations on the ability to sell the stock. The Company's no par value common stock constitute a penny stock under the Exchange Act. The classification of a penny stock makes it more difficult for a broker-dealer to sell the stock into a secondary market, which makes it more difficult for a purchaser to liquidate his/her investment. Any broker-dealer engaged by the purchaser for the purpose of selling his or her shares in us will be subject to Rules 15g-1 through 15g-10 of the Exchange Act. Rather than creating a need to comply with those rules, some broker-dealers will refuse to attempt to sell penny stock.

The penny stock rules require a broker-dealer, prior to a transaction in a penny stock not otherwise exempt from those rules, to deliver a standardized risk disclosure document prepared by the SEC, which:

- contains a description of the nature and level of risk in the market for penny stocks in both public offerings and secondary trading;
- contains a description of the broker's or dealer's duties to the customer and of the rights and remedies available to the customer with respect to a violation to such duties or other requirements of the Exchange Act, as amended;
- contains a brief, clear, narrative description of a dealer market, including "bid" and "ask" prices for penny stocks and the significance of the spread between the bid and ask price;
- contains a toll-free telephone number for inquiries on disciplinary actions;
- defines significant terms in the disclosure document or in the conduct of trading penny stocks; and
- contains such other information and is in such form (including language, type, size and format) as the SEC shall require by rule or regulation.

The broker-dealer also must provide, prior to effecting any transaction in a penny stock, to the customer:

- the bid and offer quotations for the penny stock;
- the compensation of the broker-dealer and its salesperson in the transaction;
- the number of shares to which such bid and ask prices apply, or other comparable information relating to the depth and liquidity of the market for such stock; and
- monthly account statements showing the market value of each penny stock held in the customer's account.

In addition, the penny stock rules require that prior to a transaction in a penny stock not otherwise exempt from those rules; the broker-dealer must make a special written determination that the penny stock is a suitable investment for the purchaser and receive the purchaser's written acknowledgment of the receipt of a risk disclosure statement, a written agreement to transactions involving penny stocks, and a signed and dated copy of a written suitability statement. These disclosure requirements have the effect of reducing the trading activity in the secondary market for our stock. Thus, shareholders may have difficulty selling their securities.

Our Transfer Agent

ComputerShare Investor Services is the transfer agent for our Common Stock. ComputerShare can be contacted at 250 Royal Street, Canton, MA 02021.

Securities Authorized for Issuance Under Equity Compensation Plans

We do not have any equity compensation plans in effect.

Recent Sales of Unregistered Securities

During the fourth quarter 2014 the Company issued 150,000 shares to an affiliate of William W Stewart in exchange for its interest in certain mineral interests.

Repurchases of Equity Securities of the Issuer

None

Item 6. SELECTED FINANCIAL DATA

As a smaller reporting issuer (as defined by in Item 10(f)(1) of Regulation S-K), the Company is not required to report selected financial data specified in Item 301 of Regulation S-K.

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

General Overview

We discuss and provide below our analysis of the following:

- Critical accounting policies;
- Results of operations;
- Liquidity and capital resources;
- Contractual obligations and commercial commitments;
- Off-balance sheet arrangements;
- New accounting pronouncements; and
- Controls and procedures.

As of December 31, 2014, the Company had a working capital deficit of $1,294,408 and a balance of cash and equivalents of $30,756. For the past few years we have obtained loans and incurred significant operating payables, primarily from related parties.

In the third quarter of 2011, we completed an acquisition of oil and natural gas properties in Montana, Wyoming, Colorado and Kansas. These properties include several proved undeveloped and probable drilling opportunities. However, due to our working capital deficit discussed above, our primary challenge over the next several months is to obtain additional financing to primarily address the significant working capital deficit and secondarily to seek to exploit existing drilling opportunities and possibly to acquire additional properties. We have sold some of our properties while retaining overriding royalty interests for future upside upon further development of the properties. In addition, from time to time we review opportunities for the purchase of production and underdeveloped oil and gas leases for future development. In order to purchase properties or begin substantive drilling activities we must obtain additional financing, which cannot be assured. We rely heavily on the skills of our board members in the areas of business development, capital acquisition, corporate visibility, oil and gas development, geology and operations.

There are no assurances that we can resolve our pressing capital needs, and although we have revenue from operations, our ability to execute our plans will still be dependent on our ability to raise additional capital. We have not received a commitment to finance the drilling development plan we would like to implement. Our cash flow is dependent on the prices for crude oil. We have entered into a participation agreement with an unrelated third party to participate in three wells that we had interest in the leases. We also have a line of credit for $1,500,000 of which we have drawn $549,105. We plan to use part of the balance for further development of these wells and other opportunities in the same fields.

While we seek to reduce the amount of our variable costs on an ongoing basis, it is difficult to reduce or offset our fixed expenses related to office expense, legal, accounting, transfer agent fees, reporting, corporate governance, and shareholder communications. We also incur cash costs for the due diligence, reserve studies, audits, and legal cost for these proposed acquisitions of oil and gas properties.

Our future expectation is that monthly operating expenses will remain as low as possible until we can raise additional capital address our working capital deficit.

Critical Accounting Policies

The Company has identified the accounting policies described below as critical to its business operations and the understanding of the Company's results of operations. The impact and any associated risks related to these policies on the Company's business operations is discussed throughout this section where such policies affect the Company's reported and expected financial results. The preparation of our consolidated financial statements requires the Company to make estimates and assumptions that affect the reported amount of assets and liabilities of the Company, revenues and expenses of the Company during the reporting period, and contingent assets and liabilities as of the date of the Company's consolidated financial statements. There can be no assurance that the actual results will not differ from those estimates.

Revenue Recognition

We record revenue from the sale of natural gas, NGL's and crude oil when delivery to the purchaser has occurred and title has transferred. We use the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by us. In addition, we record revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. We also reduce revenue for other owners' gas sold by us that cannot be volumetrically balanced in the future due to insufficient remaining reserves. Our remaining over- and under-produced gas balancing positions are considered in our proved oil and gas reserves. Gas imbalances at December 31, 2013 and 2014 were not material.

Use of Estimates

Preparation of our financial statements in accordance with GAAP requires management to make various assumptions, judgments and estimates that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts initially established.

The most significant areas requiring the use of assumptions, judgments and estimates relate to the volumes of natural gas and oil reserves used in calculating depreciation, depletion and amortization, which we refer to as DD&A, the amount of expected future cash flows used in determining possible impairments of oil and gas properties and the amount of future capital costs used in these calculations. Assumptions, judgments and estimates also are required in determining future asset retirement obligations, impairments of undeveloped properties, and in valuing stock-based payment awards.

Oil and Gas Producing Activities

In January 2010, the Financial Accounting Standards Board, which we refer to as the FASB, issued authoritative oil and gas reserve estimation and disclosure guidance that was effective for the Company beginning in 2010. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC final rule, "Modernization of Oil and Gas Reporting", which was also effective in 2010.

Our oil and gas exploration and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows. The costs of development wells are capitalized whether productive or nonproductive. Oil and gas lease acquisition costs are also capitalized.

Other exploration costs, including certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production DD&A rate. A gain or loss is recognized for all other sales of proved properties and is classified in other operating revenues. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unevaluated oil and gas property costs are transferred to proved oil and gas properties if the properties are subsequently determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unevaluated oil and gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage.

We review our proved oil and gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of estimated future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected.

The provision for DD&A of oil and gas properties is calculated on a field-by-field basis using the unit-of-production method. Natural gas is converted to barrel equivalents, BOE, at the rate of six Mcf to one barrel of oil. Estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values, are taken into consideration.

Asset Retirement Obligations

The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a credit-adjusted, risk-free rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method on a field-by-field basis. The associated liability is classified in current and long-term liabilities in the Consolidated Balance Sheets. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion and amortization expense in the Consolidated Statements of Operations.

Stock-based Compensation

We have not granted any stock options or warrants during the years ended December 31, 2013 and 2014 and no options or warrants were outstanding at any time during these years. We have issued shares of common stock for services performed by officers, directors and unrelated parties during 2013 and 2014. We have recorded these transactions based on the value of the services or the value of the common stock, whichever is more readily determinable.

Results of Operations for the Years Ended December 31, 2013 and 2014

Presented below is a discussion of our results of operations for the years ended December 31, 2013 and 2014.

Oil and Gas Producing Activities

On July 29, 2011, we entered into a purchase and sale agreement which resulted in our acquisition of producing oil and gas properties in Wyoming, Colorado, Kansas and Montana. Presented below is a summary of our oil and gas operations for the years ended December 31, 2013 and 2014:

	2013	2014
Oil sales	$1,791,451	$1,797,230
Natural gas sales	434,230	361,053
Royalty revenues	533	3,369
Sale of oil and natural gas properties	347,888	391,585
Total revenue	2,574,102	2,553,237
Production taxes	(187,594)	(179,660)
Lease operating expense	(679,172)	(791,142)
Plug and abandonment expenses	—	(36,250)
Depreciation, depletion, amortization and accretion (“DD&A”)	(665,123)	(767,857)
Net	$1,042,213	$ 778,328
Net barrels of oil sold	21,304	22,825
Net Mcf of gas sold	82,207	70,195
Net Barrels of Oil Equivalent (“BOE”) sold	35,005	34,524
Average price per barrel of oil sold	$ 84.09	$ 78.74
Average price for per Mcf of natural gas sold	$ 5.28	$ 5.14
Lease operating expense per BOE	$ 19.40	$ 22.92
DD&A per BOE	$ 19.01	$ 22.24

The average oil price for 2014 was $78.74 per barrel, a decrease of 5.20% compared to $84.09 per barrel for 2013. Our average natural gas price, including proceeds from sales of natural gas liquids, amounted to $5.14 per Mcf for 2014, which is an decrease of 2.65% compared to $5.28 per Mcf for 2013.

Production taxes were approximately 8.3% of our oil and gas sales for 2014 compared to 8.4% for 2013. Lease operating expense averaged $22.92 per BOE for 2014, an increase of 18.1% compared to $19.40 per BOE for 2013.

For 2014 our DD&A per BOE was $22.24 compared to $19.01 per BOE for 2013. DD&A expense for 2014 was $767,857 compared to $665,123 for 2013.

We had $391,585 in sale of oil and gas properties in 2014. This was 100% from our participation agreement for the development of the five horizontal wells in Campbell and Converse counties Wyoming.

During the fourth quarter of 2013, we sold one of our producing properties, which resulted in gross proceeds of approximately $1,004,000. This property was sold to an unrelated purchaser and pursuant to our amended purchase agreement entered into in September 2013, we were required to pay the related party sellers approximately $554,000 of the proceeds due to their contingent interest and, as a result our net proceeds were $450,000. After deducting the net book value of the property of $163,000, plus the asset retirement obligation assumed by the unrelated purchaser of $31,000, we recognized a gain of approximately $318,000.

We expect to periodically evaluate our portfolio of properties and sell additional properties if we believe a sale can be completed on terms that provide attractive returns.

Gas Gathering Activities

We have owned and operated a natural gas gathering system (pipeline and compressor station) for coal bed methane properties in the Powder River Basin of Wyoming since 2006. Due to a reduction in natural gas prices, all wells in the field have been shut-in since June 2011.

Presented below is a summary of operating costs for the years ended December 31, 2013 and 2014:

	2013	2014	Percent Change
Related party- cost of production	$ —	$ —	0%
Unrelated parties:			
Compressor rental	—	—	0%
Pumper costs	—	—	0%
Transportation	—	—	0%
Property taxes	4,470	3,792	(17.9%)
Land rent, utilities, repairs and other	9,670	5,134	(46.9%)
Total unrelated party costs	14,140	8,926	(63.1%)
Total	$14,140	$8,926	(63.1%)

Depreciation expense related to the gas gathering system was $44,219 for both 2013 and 2014.

In July 2011, we acquired the entire field of coal bed methane wells as part of our property acquisition discussed above. While these wells are not economic at current prices being received for natural gas related to the production capability from the existing geologic formation, we have geologic and engineering data that suggest gas reserves exist on these properties by drilling new wells and/or recompleting the existing wells to several new geologic formations. While we believe that reserves exist, we do not expect to undertake any drilling activities on this property until natural gas prices increase significantly. We currently believe we should be able to recover our net capitalized costs related to these properties and the related gas gathering system. However, we are continuing to evaluate our alternatives and there is a possibility that an impairment charge will be required in the future.

General and Administrative

Presented below is a summary of general and administrative expenses for the years ended December 31, 2013 and 2014:

	2013	2014	Change
Director fees	$ 2,250	$ 20,450	$ 18,200
Investor relations	98,505	65,833	(32,672)
Legal, auditing and professional services	147,348	146,581	(767)
Consulting and executive services:			
Related parties	123,000	220,800	97,800
Unrelated parties	—	—	—
Other administrative expenses	59,712	72,807	13,095
Depreciation	570	570	—
Total general and administrative expenses	$431.385	$527,041	$ 95,656

General and administrative expenses increased by $95,656 for 2014 compared to 2013, primarily due to decreases in investor relations and legal, auditing and professional fees; and increases in consulting and executive services, directors fees, and other administrative expenses.

Operating income

Income from operations for the year ended December 31, 2014 was $198,142 compared to income from operations of $552,469 for the year ended December 31, 2013. The decrease in operating income of $354,327 was primarily due to the additional costs in oil & gas operations and additional overhead charges.

Interest Expense

Interest expense increased from $132,186 for 2013 to $135,773 for 2014, the increase of $3,605. The increase was due primarily to the rates on the new notes.

Net income applicable to common shareholders

For the year ended December 31, 2014, net income applicable to common shareholders was $70,945 compared to income applicable to common shares of $3,367,515 for the year ended December 31, 2014. The net income applicable to common shareholders included a $3,160,026 discount on the redemption of 512.5 shares of the Company's Series A1 Preferred Stock for December 31, 2013, and a $17,951 discount on the redemption of 10 shares of the Company's Series A1 Preferred Stock for December 31, 2014. The discount on the preferred stock redemption is the difference between the carrying value per share and the $0.75 per share paid by the Company to the preferred shareholders.

Liquidity and Capital Resources

We had a working capital deficit as of December 31, 2014 of approximately $1,295,000, compared to a working capital deficit of $620,000 at December 31, 2013. We generated positive operating cash flow of approximately $660,000 for 2014 compared to operating cash flow of approximately $384,000 for 2013.

During 2014 our investing activities used net cash of $(326,000). We had capital expenditures of $640,000. During 2014, we generated net proceeds of approximately $313,000 from participation agreement in oil and gas property. During 2013 our investing activities provided net cash of $172,000. We had capital expenditures of $307,000. During 2013, we generated net proceeds of approximately $479,000 from the sale of a 100% working interest in an oil and gas property and the sale of some equipment. We realized a gain of approximately $348,000 on the sale of this property and equipment.

During 2014 our financing activities used net cash of approximately $778,000. The 2014 financing activities included borrowings of approximately $623,000. These funds were needed to fund our operations, a redemption of Preferred Stock Series A of $15,500, repurchase of 1,200,000 shares of common stock for $228,000, and repayment of notes payable of $1,157,000. During 2013 our financing activities used net cash of approximately $86,000. The 2013 financing activities included borrowings of approximately $1,043,000. These funds were needed to fund our operations as well as to make a $392,000 Preferred Stock Series A dividend payment, redemption of Preferred Stock Series A of $50,000, and repayment of notes payable of $687,000.

We also expect to evaluate acquisitions that are consistent with our business objective of acquiring interests in traditional oil and gas ventures, and seeking properties that offer profit potential from overlooked and by-passed reserves of oil and natural gas. The Company has participated as a working interest owner in the four horizontal wells which were drilled and completed in Campbell County, Wyoming in the Turner zone and one well in Converse County, Wyoming in the Turner Zone. The following is a description of the wells:

1) The Thielen #1-21 is in Section 21 Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,350 including the lateral. The Company has an approximate 1.06% working interest. We had production from this well for eleven months in 2014.

2) The Thielen #2-21 is in Section 21 Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,330 feet including the lateral. The Company has an approximate 1.06% working interest. We had production from this well for seven months in 2014.

3) The Starlight Federal 28H is located in Section 7, Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,310 including the lateral. The Company has an approximate 0.7025% working interest. We had production from this well for 10 months in 2014.

4) The Starlight Federal 30H is located in Section 7, Township 43N Campbell County Wyoming. This well was drilled to a total depth of approximately 15,310 including the lateral. The Company has an approximate 1.450088% working interest. We had no production from this well in 2014.

5) The Wibaux Gold Federal 4076-10-03-1SH is located in Section 10, Township 43N Converse County Wyoming. This well was drilled to a total depth of approximately 20,185 including the lateral. The Company has an approximate 0.2697755% working interest. We had one month production from this well in 2014.

In order to execute our development drilling plans and to acquire additional interests in oil and gas properties that meet our objectives, we need to obtain significant additional financing. From the time we acquired our existing properties in July 2011, we have sold our interests in some of those properties, which resulted in aggregate net proceeds from three sales of $6,377,000, which was used to repay acquisition indebtedness. We intend to only sell properties that can be liquidated for a premium and there can be no assurance that we will continue to generate any proceeds from the sale of our properties.

The following recent financings are part of the funding of our business plan:

1). Bank Line of Credit

On January 28, 2014, we entered into a line of credit loan agreement with CityWide Bank for $1,500,000 due January 15, 2015, the loan was extended by the bank until April 28, 2015. The Company is negotiating a longer extension pending the receipt of the reserve study and the 10-K by the bank. The terms of the note are as follows: 1) the accrued interest is payable monthly starting February 28, 2014, 2) the interest rate is variable based on an index calculated based on a prime rate as published by the Wall Street Journal index (currently 3.25%) plus an add on index with the current and minimum rate of 6.5%., the note has draw provisions, with the first draw of $479,701.39; 4) the note is secured by seven wells and leases owned by the Company, a certificate of deposit for $500,000 at CityWide Bank pledged by a unrelated third party, and 5) the personal guarantee of the Nicholas Scheidt, Chief Executive Officer. The amount eligible for borrowing on the Credit Facility is limited to the lesser of (i) 65% of the Company's PV10 value of its carbon reserves based upon the most current engineering reserve report or (ii) 48 month cumulative cash flow based upon the most current engineering reserve report. In addition to the borrowing base limitation, the Company is required to maintain and meet certain affirmative and negative covenants and conditions in order to draw advances on the Credit Facility. The Credit Facility contains certain representations, warranties, and affirmative and negative covenants applicable to the Company, which are customarily applicable to senior secured loan facilities. Key covenants include limitations on indebtedness, restricted payments, creation of liens on oil and gas properties, hedging transactions, mergers and consolidations, sales of assets, use of loan proceeds, change in business, and change in control. The above-referenced promissory notes contain customary default and acceleration provisions and provide for a default interest rate of 21% per annum. In addition, the Credit Facility contains customary events of default, including: (a) failure to pay any obligations when due; (b) failure to comply with certain restrictive covenants; (c) false or misleading representations or warranties; (d) defaults of other indebtedness; (e) specified events of bankruptcy, insolvency or similar proceedings; (f) one or more final, non-appealable judgments in excess of $50,000 that is not covered by insurance; (g) change in control (25% threshold); (h) negative events affecting the Guarantor; and (i) lender in good faith believes itself insecure. In an event of default arising from the specified events, the Credit Facility provides that the commitments thereunder will terminate and the Lender may take such other actions as permitted including, declaring any principal and accrued interest owed on the line of credit to become immediately due and payable. The Credit Facility is secured by a security interest in substantially all of the assets of the Company, pursuant to a Security Agreement, Deed of Trust and Assignment of As-Extracted Collateral entered into between the Company and Citywide Banks. As of December 31, 2014 the outstanding balance of the loan is $549,105.

2) Related Party Notes Payable

On January 1, 2014, we memorialized certain of our short-term liabilities into formal promissory notes. These outstanding advances and other notes payable are now included in single promissory notes, all have been reported previously in our financial statements. Information concerning these promissory notes is set forth in the table below.

Name of Holder	Position	Principal Amount	Interest Rate	Monthly P&I Payment Amount	Number of Monthly Payments
Donald W. Prosser	CFO & Director	$28,500	7.00%	$ 564.33	60
Charles B. Davis	COO & Director	$66,500	7.00%	$1,316.78	60
William Stewart	Director	$49,500	7.00%	$ 980.16	36

The above-referenced promissory notes contain customary default and acceleration provisions and provide for a default interest rate of 18% per annum.

In addition, we also issued an unsecured promissory note in the amount of $792,151 on January 1, 2014 to DNR Oil & Gas, Inc. (“DNR”). DNR is a company controlled by one of our directors, Charles B. Davis. The DNR note accrues interest at the rate of 2.50% for the calendar years 2014 and 2015, 4.00% for the calendar year 2016, 6.00% for the calendar year 2017 and 8.00% for the remainder of the term of the DNR note. The DNR note matures on January 1, 2019. The DNR note requires payments as follows:

- One payment of $250,000 in 2016;
- One payment of $250,000 in 2017;
- One payment of $250,000 in 2018; and
- The balance of principal and accrued interest on or before January 1, 2019.

The DNR note contains customary default and acceleration provisions and provides for a default interest rate of 18% per annum and is subordinated to the bank line of credit. The note is subordinated to the bank line of credit.

3)Extension of Existing Promissory Notes

In June 2013, in connection with the conversions of Series A1 Preferred Stock by Burlingame Equity Investors II, LP and Burlingame Equity Investors Master Fund, LP, the Company issued unsecured promissory notes in the original principal amounts of $48,000 and $552,000, respectively, with interest at 7% per annum payable quarterly and all unpaid interest and principal due on July 23, 2014. In connection with our new line of credit, we have agreed with the holders of these two existing notes to make a partial prepayment on the principal balance of the Notes in exchange for an extension of the maturity date to April 27, 2015. Information concerning the principal pay down and new maturity date is set forth in the following table.

Name of Holder	Principal Balance Before Pay down	Principal Pay down	Remaining Principal Balance
Burlingame Equity Investors II, LP	$ 44,000	$ 26,251	$ 17,749
Burlingame Equity Investors Master Fund, LP	$ 506,000	$ 340,749	$ 165,251

If oil and gas prices decrease materially from current levels and additional debt or equity funding is unavailable on acceptable terms, or at all, our strategy would include some or all of the following: (i) defer development drilling on our existing properties, (ii) forego additional oil and gas property acquisitions, (iii) shut-in any marginal or uneconomic wells, (iv) attempt to negotiate the issuance of common stock in exchange for services, (v) pay preferred stock dividends through the issuance of our common stock, and (vi) review and implement other opportunities to reduce general, administrative and operating expenses.

Contractual Obligations and Commercial Commitments

As of December 31, 2014, we have future minimum lease payments of approximately $5,000. This amount is payable during the years ending December 31, 2015, 2016, 2017 and after 2018 in the amounts of $1,000, $1,000, $1,000, $1,000, and $1,000, respectively.

Off-Balance Sheet Arrangements

In connection with the related party acquisition of oil and gas properties in the third quarter of 2011, we acquired interests in certain geologic zones of the properties. For a period of ten years after the closing date, the Colorado and Kansas properties provide for additional consideration that is payable to Sellers based on increases in Nymex prices for oil and natural gas, without regard to changes in the Company's oil and natural gas reserves (referred to as the "Price Increase Factor"). If Nymex thresholds of $90, $100, $110, $125 and $150 per barrel of oil are exceeded for periods of 61 days or more, incremental purchase consideration of $250,000, $250,000, $500,000, $500,000 and $2,000,000, respectively, will be payable to Sellers. Similarly, if Nymex thresholds of $5.00, $6.00, $7.50, $10.00 and $12.00 per MMbtu of natural gas are exceeded for periods of 61 days or more, incremental purchase consideration of $50,000, $50,000, $150,000, $250,000 and $250,000, respectively, will be payable to Sellers.

The Colorado and Kansas properties also provide for additional consideration that is payable to Sellers if reserves classified as "possible" are converted to "proved producing reserves" through drilling or recompletion activities over a period of ten years after the closing date (referred to as the "Possible Reserve Factor"). For such increases in oil reserves, the Sellers are entitled to additional consideration of $250,000 for each increase of 20,000 net barrels; and for such increases in natural gas reserves, the Sellers are entitled to additional consideration of $150,000 for each increase of 150,000 Mcf of natural gas.

The Possible Reserve Factor also requires a multiplier effect from 1 to 5 depending on the Price Increase Factor that is effective when the proved producing reserves are obtained. For example, the Possible Reserve Factor consideration would be multiplied by 2 if the oil Price Increase Factor of $100 is in effect when the proved producing reserves are confirmed. Similarly, the Possible Reserve Factor consideration would be multiplied by 2 if a natural gas Price Increase Factor of $6.00 per MMbtu is in effect when the proved producing natural gas reserves are confirmed. The maximum increase in purchase price for the Kansas and Colorado properties is limited to $5 million.

Additional consideration is also payable for the properties located in Wyoming to the extent that the Company increases proved producing reserves through future drilling or recompletion activities in formations that are not producing as of the closing date under the Possible Reserve Factor. Similar to the properties in Colorado and Kansas, the Possible Reserve Factor will be multiplied by a factor of 1 to 5 depending on the Price Increase Factor that is effective when the proved producing reserves are obtained.

Furthermore, if the Company sells any of the properties in Wyoming, the Sellers have retained an interest of 70% in the net sales proceeds (after the Company receives a recovery of 125% of the original agreed-upon allocation as contained in the table above).

The maximum increase in purchase price (including Sellers retained interest of 70% for the Wyoming properties discussed in the preceding paragraph) for all properties in all states is limited to $25 million. Due to the sale of the Separate Interests discussed below, accrual of $500,000 due to sustained increases in oil prices over $100 per barrel, and the sale of a second property in February 2012, and third property in December 2013, the maximum future consideration has been reduced by approximately $5.8 million to $19.2 million as of December 31, 2013.

SEC Investigation

The Denver Regional Office of the Securities and Exchange Commission is conducting a non-public, formal, investigation ("SEC Investigation") to determine whether there have been violations of certain provisions of the federal securities laws relating to the Company, its management and third parties. The principal areas of the SEC Investigation relate to the sale of certain Company securities, possible trading manipulation activities with respect to the Company's common stock, and potential violations of the federal broker-dealer registration laws by persons or entities in connection with the purchase or sale of the Company's securities. To date, neither the Company nor any of its directors, officers, or employees have been accused of any wrongdoing by the SEC. We also have been informed by the SEC that the existence of this investigation does not mean that the SEC has concluded that anyone has broken the law or that the SEC has a negative opinion of any person, entity, or security. We have been cooperating fully with the SEC. We cannot reasonably estimate the timing of the SEC investigation, nor can we predict whether or not it might have a material adverse effect on our business.

New Accounting Pronouncements

In January 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-1, *Balance Sheet: Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which amended FASB Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet.* The main objective in developing this update was to address implementation issues about the scope of ASU 2011-11, *Balance Sheet: Disclosures about Offsetting Assets and Liabilities.* The amendments clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with Topic 815, *Derivatives and Hedging*, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. This provision is effective for fiscal years beginning on or after January 1, 2013. Adoption of this update did not have a material impact on the Company's disclosures or financial statements.

In February 2013, the FASB issued ASU 2013-2, *Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income,* which amended ASC Topic 220, *Comprehensive Income*. The objective of this update was to improve the reporting of reclassifications out of accumulated other comprehensive income. The amendment did not change the requirements for reporting net income or other comprehensive income in financial statements. However, the amendment required an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This provision is effective for interim and annual periods beginning after December 15, 2012. Adoption of this update did not have a material impact on the Company's disclosures or financial statements.

In July 2013, the FASB issued ASU 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*. The objective of ASU 2013-11 is to provide guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

In June 2014, the FASB issued ASU No. 2014-12, Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period ("ASU 2014-12"). The amendments in ASU 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Accounting Standards Codification Topic No. 718, "Compensation – Stock Compensation" ("ASC 718"), as it relates to awards with performance conditions that affect vesting to account for such awards. The amendments in ASU 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted. Entities may apply the amendments in ASU 2014-12 either: (a) prospectively to all awards granted or modified after the effective date; or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The adoption of ASU 2014-12 is not expected to have a material effect on the Company's consolidated financial statements or disclosures.

In April 2014, the FASB issued ASU 2014-08, “Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity.” ASU 2014-08 changes the criteria for reporting a discontinued operation. Under the new pronouncement, a disposal of a part of an organization that has a major effect on its operations and financial results is a discontinued operation. The Company is required to adopt ASU 2014-08 prospectively for all disposals or components of its business classified as held for sale during fiscal periods beginning after December 15, 2014. The adoption of ASU 2014-08 is not expected to have a material effect on the Company’s consolidated financial statements or disclosures.

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers” (“ASU 2014-09”), which provides guidance for revenue recognition. ASU 2014-09 affects any entity that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets and supersedes the revenue recognition requirements in Topic 605, “Revenue Recognition,” and most industry-specific guidance. This ASU also supersedes some cost guidance included in Subtopic 605-35, “Revenue Recognition- Construction-Type and Production-Type Contracts.” ASU 2014-09’s core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which a company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under today’s guidance, including identifying performance obligations in the contract, estimating the amount of variable consideration to include in the transaction price and allocating the transaction price to each separate performance obligation. ASU 2014-09 is effective for the Company beginning January 1, 2017 and, at that time, the Company may adopt the new standard under the full retrospective approach or the modified retrospective approach. Early adoption is not permitted. The Company is currently evaluating the method and impact the adoption of ASU 2014-09 will have on the Company’s consolidated financial statements and disclosures.

In August 2014, the FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity’s Ability to Continue as a Going Concern* (“ASU 2014-15”). ASU 2014-15 will explicitly require management to assess an entity’s ability to continue as a going concern, and to provide related footnote disclosure in certain circumstances. The new standard will be effective for all entities in the first annual period ending after December 15, 2016. Earlier adoption is permitted. We are currently evaluating the impact of the adoption of ASU 2014-15.

Other accounting standards that have been issued or proposed by the FASB, or other standards-setting bodies, that do not require adoption until a future date are not expected to have a material impact on the Company’s financial statements upon adoption.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

ARÊTE INDUSTRIES, INC. AND SUBSIDIARIES

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CAUSEY DEMGEN & MOORE P.C.
1125 Seventeenth Street, Suite 1450
Denver, Colorado 80202

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders
of Arête Industries, Inc.

We have audited the accompanying consolidated balance sheet of Arête Industries, Inc. and Subsidiaries as of December 31, 2013 and 2014, and the related consolidated statements of operations, stockholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of Arête Industries, Inc. and Subsidiaries at December 31, 2013 and 2014, and the results of their operations and their cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

Denver, Colorado
April 15, 2015

/s/ CAUSEY DEMGEN & MOORE P.C.

ARÊTE INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
December 31,

	2013	2014
ASSETS		
Current Assets:		
Cash and equivalents	$ 476,323	$ 30,755
Receivable from DNR Oil & Gas, Inc.:		
Oil and gas sales, net of production costs	230,029	103,668
Other	2,368	78,273
Prepaid expenses and other	38,177	34,222
Total Current Assets	746,897	246,918
Property and Equipment:		
Oil and gas properties, at cost, successful efforts method:		
Proved properties	9,555,897	10,222,668
Unevaluated properties	314,336	348,836
Natural gas gathering system	442,195	442,195
Furniture and equipment	22,522	22,522
Total property and equipment	10,334,950	11,036,221
Less accumulated depreciation, depletion and amortization	(2,094,337)	(2,840,173)
Net Property and Equipment	8,240,613	8,196,048
TOTAL ASSETS	$ 8,987,510	$ 8,442,966
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts payable:		
Payable to DNR Oil & Gas, Inc.:		
Operator fees and other	$ 36,000	$ 36,000
Unrelated parties	17,806	43,365
Notes and advances payable - current portion:		
Directors and affiliates	717,833	288,258
Unrelated parties	325,000	872,239
Accrued interest expense	52,242	3,279
Accrued consulting - related party	—	21,800
Director fees payable in common stock	450	20,900
Current portion of asset retirement obligations	159,782	191,843
Other accrued costs and expenses	57,210	63,642
Total Current Liabilities	1,366,323	1,541,326
Long-Term Liabilities:		
Contingent acquisition costs payable to DNR Oil & Gas, Inc.	250,000	250,000
Notes and advances payable, net of current portion:		
DNR Oil & Gas, Inc.:	792,151	792,151
Directors and affiliates	246,639	62,440
Unrelated parties	425,000	63,534
Asset retirement obligations, net of current portion	522,421	557,170
Total Long-Term Liabilities	2,236,211	1,725,295
Total Liabilities	3,602,534	3,266,621
Commitments and Contingencies:	—	—
Stockholders' Equity:		
Convertible Class A preferred stock; $10,000 face value per share, authorized 1,000,000 shares:		
Series 1; authorized 30,000 shares, issued and outstanding 10 shares in 2013 and 0 shares in 2014, liquidation preference of $111,250 in 2013 and $-0- in 2014.	95,451	—
Series 2; authorized 2,500 shares, issued and outstanding no shares in 2013 and 2014	—	—
Common stock, no par value; authorized 499,000,000 shares, issued and outstanding 13,608,459 in 2013 and 12,558,459 in 2014	21,488,387	21,294,887
Accumulated deficit	(16,198,862)	(16,118,542)
Total Stockholders' Equity	5,384,976	5,176,345
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 8,987,510	$ 8,442,966

The Accompanying Notes are an Integral Part of These Financial Statements.

ARÊTE INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF OPERATIONS
Years Ended December 31, 2013 and 2014

	2013	2014
Revenues:		
Oil and natural gas sales	$ 2,225,681	$ 2,158,283
Royalty revenues	533	3,369
Sale of oil and natural gas properties	347,888	391,585
Total revenues	2,574,102	2,553,237
Operating Expenses:		
Oil and gas producing activities:		
Lease operating expenses	679,172	791,142
Production taxes	187,594	179,660
Plug and abandonment expenses	—	36,250
Depreciation, depletion, amortization and accretion	665,123	767,857
Gas gathering:		
Operating expenses	14,140	8,926
Depreciation	44,219	44,219
General and administrative expenses:		
Director fees	2,250	20,450
Investor relations	98,505	65,833
Legal, auditing and professional fees	147,348	146,581
Consulting fees executive services:		
Related parties	123,000	220,800
Unrelated parties	—	—
Other administrative expenses	59,712	72,807
Depreciation	570	570
Total operating expenses	2,021,633	2,355,095
Operating income	552,469	198,142
Interest income	1	—
Interest expense	(132,168)	(135,773)
Total other income (expense)	(132,167)	(135,773)
Income before income taxes	420,302	62,369
Income tax benefit (expense)	—	—
Net income	$ 420,302	$ 62,369
Net Income Applicable to Common Stockholders:		
Net income	$ 420,302	$ 62,369
Redemption of preferred stock	3,160,026	17,951
Accrued Preferred stock dividends	(212,813)	(9,375)
Net income applicable to common stockholders	$ 3,367,515	$ 70,945
Earnings Per Share Applicable to Common Stockholders:		
Basic	$ 0.31	$ 0.01
Diluted	$ 0.31	$ 0.01
Weighted Average Number of Common Shares Outstanding:		
Basic	10,760,000	12,450,000
Diluted	10,760,000	12,450,000

The Accompanying Notes are an Integral Part of These Financial Statements.

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ARÊTE INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2013 and 2014

	Class A Preferred Stock		Common Stock		Accumulated	
	Shares	Amount	Shares	Amount	Deficit	Total
Balances, December 31, 2012	522.5	4,987,326	7,979,801	17,151,097	(16,227,289)	5,911,134
Issuance of common stock to unrelated parties:						
Valued at $0.40 per share for consulting services	—	—	45,000	18,000		18,000
Valued at $0.30 per share for consulting services	—	—	20,000	6,000		6,000
Valued at $0.30 per share for loan fees	—	—	20,000	6,000		6,000
Issuance of common stock in exchange for consulting services provided by related parties:						
Valued at $0.67 per share for June 2013 services			44,823	30,000		30,000
Issuance of common stock for Board of Director's fees:						
Valued at an average of $0.49 per share for 2013	—	—	72,170	35,415		35,415
Conversation of Series A						
Preferred Stock	(512.5)	(4,891,875)	5,426,665	4,241,875		(650,000)
Preferred dividend paid					(391,875)	(391,875)
Net income	—	—	—	—	420,302	420,302
Balances, December 31, 2013	10.0	$ 95,451	13,608,459	$21,488,387	$(16,198,862)	$5,384,976
Issuance of common stock in exchange for purchase of oil properties from a related parties:						
Valued at $0.23 per share October 2014			150,000	34,500		34,500
Redeemption of Common Stock			(1,200,000)	(228,000)		(228,000)
Redeemption of Preferred Stock	(10.0)	(95,451)			17,951	(77,500)
Net income	—	—	—	—	62,369	62,369
Balances, December 31, 2014	—	$ —	12,558,459	$21,294,887	$(16,118,542)	$5,176,345

The Accompanying Notes are an Integral Part of These Financial Statements.

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ARÊTE INDUSTRIES, INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013 and 2014

	2013	2014
Cash Flows from Operating Activities:		
Net income	$ 420,302	$ 62,369
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	642,816	745,836
Accretion of discount on asset retirement obligations	67,096	66,810
Gain on sale of oil and gas properties	(347,888)	(391,585)
Common stock issued in exchange for services	18,000	—
Changes in operating assets and liabilities:		
Accounts receivable	(153,519)	101,740
Prepaid expenses and other	22,857	3,955
Accounts payable	(93,136)	25,559
Accrued costs and expenses	(192,397)	44,235
Net cash provided by operating activities	384,131	658,919
Cash Flows from Investing Activities:		
Capital expenditures for oil and gas properties	(307,465)	(639,259)
Proceeds from sale of oil and gas properties	1,033,324	312,789
Contingent consideration paid to DNR under sharing arrangement	(554,193)	—
Net cash provided by (used in) investing activities	171,666	(326,470)
Cash Flows from Financing Activities:		
Proceeds from notes and advance payable	1,042,670	622,638
Principal payments on notes payable	(687,190)	(1,157,155)
Redemption of common stock	—	(228,000)
Payment of dividends on preferred stock	(391,875)	—
Redemption of preferred stock	(50,000)	(15,500)
Net cash (used in) financing activities	(86,395)	(778,017)
Net increase (decrease) in cash and equivalents	469,402	(445,568)
Cash and equivalents, beginning of year	6,921	476,323
Cash and equivalents, end of year	$ 476,323	$ 30,755
Supplemental Disclosure of Cash Flow Information:		
Cash paid for interest	$ 117,578	$ 123,669
Cash paid for income taxes	$ —	$ —
Supplemental Disclosure of Non-cash Investing and Financing Activities:		
Issuance of common stock for asset purchase	$ —	$ 34,500
Asset retirement obligations assumed upon sale of oil and gas properties	$ 32,161	$ —
Conversation of Series A-1 preferred stock to note payable	$ 600,000	$ 62,000

The Accompanying Notes are an Integral Part of These Financial Statements.

ARÊTE INDUSTRIES, INC. AND SUBSIDIARIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
For the Years Ended December 31, 2013 and 2014

1. Organization and Nature of Operations

Arête Industries, Inc. ("Arête" or the "Company"), is a Colorado corporation that was incorporated on July 21, 1987. The Company owns 100% of Arête Energy, Inc. which is an inactive subsidiary which has no assets, liabilities or operations. Arête has operated a natural gas gathering system in Wyoming since 2006 and on July 29, 2011 the Company purchased oil & natural gas properties in Colorado, Montana, Kansas, and Wyoming.

The Company seeks to focus on acquiring interests in traditional oil and gas ventures, and seek properties that offer profit potential from overlooked and by-passed reserves of oil and natural gas, which may include shut-in wells, in-field development, stripper wells, re-completion and re-working projects. In addition, the Company's strategy includes purchase and sale of acreage prospective for oil and natural gas and seeking to obtain cash flow from the sale and farm out of such prospects.

2. Summary of Significant Accounting Policies

Use of Estimates

Preparation of the Company's financial statements in accordance with GAAP requires management to make various assumptions, judgments and estimates that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events and, accordingly, actual results could differ from amounts initially established.

The most significant areas requiring the use of assumptions, judgments and estimates relate to the volumes of natural gas and oil reserves used in calculating depreciation, depletion and amortization ("DD&A"), the amount of expected future cash flows used in determining possible impairments of oil and gas properties and the amount of future capital costs used in these calculations. Assumptions, judgments and estimates also are required in determining future asset retirement obligations, impairments of undeveloped properties, and in valuing stock-based payment awards.

The only component of comprehensive income that is applicable to the Company is net income (loss). Accordingly, a separate statement of comprehensive income (loss) is not included in these financial statements.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of Arête and its inactive subsidiary, Arête Energy, Inc. All intercompany accounts and transactions have been eliminated in consolidation.

Reclassifications

The Company has condensed certain line items within the current period financial statements, and certain prior period balances were reclassified to conform to the current year presentation. Reclassifications did not have any impact on the Company's previously reported working capital, results of operations or cash flows.

Cash Equivalents

For purposes of the statement of cash flows, the Company considers cash and all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Gas Gathering System, Furniture and Equipment

The Company's gas gathering system and its furniture and equipment are stated at cost. Material expenditures that increase the life of an asset are capitalized and depreciated over the estimated remaining useful life of the asset. The cost of normal maintenance and repairs is charged to operating expenses as incurred. Upon disposal of an asset, the cost of the asset and the related accumulated depreciation are removed from the accounts, and any gains or losses will be reflected in current operations. For the gas gathering system, depreciation is computed using the straight line method over an estimated useful life of ten years. Depreciation of furniture and equipment is computed using the straight-line method over an estimated useful life of five years.

Oil and Gas Producing Activities

The Company's oil and gas exploration and production activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending determination of whether the well has proved reserves. If an exploratory well does not result in proved reserves, the costs of drilling the well are charged to expense and included within cash flows from investing activities in the Consolidated Statements of Cash Flows. The costs of development wells are capitalized whether productive or nonproductive. Oil and gas lease acquisition costs are also capitalized.

Other exploration costs, including certain geological and geophysical expenses and delay rentals for oil and gas leases, are charged to expense as incurred. The sale of a partial interest in a proved property is accounted for as a cost recovery and no gain or loss is recognized as long as this treatment does not significantly affect the unit-of-production DD&A rate. A gain or loss is recognized for all other sales of proved properties and is classified in other operating revenues. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unevaluated oil and gas property costs are transferred to proved oil and gas properties if the properties are subsequently determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unevaluated oil and gas properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage.

The Company reviews its proved oil and gas properties for impairment annually or whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and gas properties to fair value. The factors used to determine fair value include, but are not limited to, recent sales prices of comparable properties, the present value of estimated future cash flows, net of estimated operating and development costs using estimates of reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected.

The provision for DD&A of oil and gas properties is calculated based on proved reserves on a field-by-field basis using the unit-of-production method. Natural gas is converted to barrel equivalents, BOE, at the rate of six Mcf of natural gas to one barrel of oil. Estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values, are taken into consideration.

In January 2010, the Financial Accounting Standards Board ("FASB") issued authoritative oil and gas reserve estimation and disclosure guidance that was effective for the Company beginning in 2010. This guidance was issued to align the accounting oil and gas reserve estimation and disclosure requirements with the requirements in the SEC final rule, "Modernization of Oil and Gas Reporting", which was also effective in 2010. Many of the revisions were updates to definitions in the existing oil and gas rules to make them consistent with the Petroleum Resource Management System, which was developed by several petroleum industry organizations and is a widely accepted standard for the management of petroleum resources. Key revisions include a requirement to use 12-month average pricing determined by averaging the first of the month prices for the preceding 12 months rather than year-end pricing for estimating proved reserves, the ability to include nontraditional resources in reserves, the ability to use new technology for determining proved reserves, and permitting disclosure of probable and possible reserves.

Asset Retirement Obligations

The estimated fair value of the future costs associated with dismantlement, abandonment and restoration of oil and gas properties is recorded generally upon acquisition or completion of a well. The net estimated costs are discounted to present values using a credit-adjusted, risk-free rate over the estimated economic life of the oil and gas properties. Such costs are capitalized as part of the related asset. The asset is depleted on the units-of-production method on a field-by-field basis. The associated liability is classified in current and long-term liabilities in the Consolidated Balance Sheets. The liability is periodically adjusted to reflect (1) new liabilities incurred, (2) liabilities settled during the period, (3) accretion expense and (4) revisions to estimated future cash flow requirements. The accretion expense is recorded as a component of depreciation, depletion and amortization expense in the Consolidated Statements of Operations.

Revenue Recognition

The Company records revenues from the sale of natural gas, natural gas liquids ("NGL") and crude oil when delivery to the purchaser has occurred and title has transferred. The Company uses the sales method to account for gas imbalances. Under this method, revenue is recorded on the basis of gas actually sold by the Company. In addition, the Company will record revenue for its share of gas sold by other owners that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company also reduces revenue for other owners' gas sold by the Company that cannot be volumetrically balanced in the future due to insufficient remaining reserves. The Company's remaining over- and under-produced gas balancing positions are considered in the Company's proved oil and gas reserves. Gas imbalances at December 31, 2013 and 2014 were not material.

Environmental Liabilities

Environmental expenditures that relate to an existing condition caused by past operations and that do not contribute to current or future revenue generation are expensed. Liabilities are accrued when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. As of December 31, 2013 and 2014, the Company had not accrued for nor been fined or cited for any environmental violations that would have a material, adverse effect upon capital expenditures, operating results or the competitive position of the Company.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil, and all of the Company's operations are conducted in the continental United States. Consequently, the Company currently reports as a single industry segment.

Stock-Based Compensation

The Company did not grant any stock options or warrants during the years ended December 31, 2013 and 2014 and no options or warrants were outstanding at any time during these years. The Company has issued shares of common stock for services performed by officers, directors and unrelated parties during 2013 and 2014. The Company has recorded these transactions based on the value of the services or the value of the common stock, whichever is more readily determinable.

Income Taxes

The Company accounts for income taxes under ASC 740. Temporary differences are differences between the tax basis of assets and liabilities and their reported amounts in the financial statements that will result in taxable or deductible amounts in future years. The Company's temporary differences consist primarily of tax operating loss carry forwards and start-up costs capitalized for tax purposes.

Fair Value of Financial Instruments

Cash, accounts payable, accrued liabilities and notes payable are carried in the Consolidated Financial Statements in amounts which approximate fair value because of the short-term maturity of these instruments.

Earnings Per Share

Basic net income (loss) per share of common stock is calculated by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares outstanding during each period. Diluted net income (loss) attributable to common stockholders is calculated by dividing net income (loss) attributable to common stockholders by the weighted average number of common shares outstanding and other dilutive securities. The only potentially dilutive securities for the diluted earnings per share calculations consist of Series 1 preferred stock that is convertible into common stock at an exchange price of $3.30 per common share. As of December 31, 2013, the convertible preferred stock had an aggregate liquidation preference of $30,303 and was convertible to 33,712 shares of common stock. These shares were excluded from the earnings per share calculation because it was anti-dilutive to assume conversion immediately prior to the last dividend payment date, which would have eliminated preferred dividends for the fourth quarters of 2013 and 2014 from the earnings per share calculation.

New Accounting Pronouncements

In January 2013, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2013-1, *Balance Sheet: Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities,* which amended FASB Accounting Standards Codification ("ASC") Topic 210, *Balance Sheet.* The main objective in developing this update was to address implementation issues about the scope of ASU 2011-11, *Balance Sheet: Disclosures about Offsetting Assets and Liabilities.* The amendments clarify that the scope of ASU 2011-11 applies to derivatives accounted for in accordance with Topic 815, *Derivatives and Hedging*, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset in accordance with ASC 210-20-45 or ASC 815-10-45 or subject to an enforceable master netting arrangement or similar agreement. This provision is effective for fiscal years beginning on or after January 1, 2013. Adoption of this update did not have a material impact on the Company's disclosures or financial statements.

In February 2013, the FASB issued ASU 2013-2, *Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income,* which amended ASC Topic 220, *Comprehensive Income*. The objective of this update was to improve the reporting of reclassifications out of accumulated other comprehensive income. The amendment did not change the requirements for reporting net income or other comprehensive income in financial statements. However, the amendment required an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, an entity is required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. This provision is effective for interim and annual periods beginning after December 15, 2012. Adoption of this update did not have a material impact on the Company's disclosures or financial statements.

In July 2013, the FASB issued ASU 2013-11, *Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists*. The objective of ASU 2013-11 is to provide guidance on financial statement presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. ASU 2013-11 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2013. The adoption of this standard did not have an impact on the Company's consolidated financial statements

In June 2014, the FASB issued ASU No. 2014-12, Accounting for Share-Based Payments When the Terms of an Award Provide That a Performance Target Could Be Achieved after the Requisite Service Period ("ASU 2014-12"). The amendments in ASU 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period be treated as a performance condition. A reporting entity should apply existing guidance in Accounting Standards Codification Topic No. 718, "Compensation – Stock Compensation" ("ASC 718"), as it relates to awards with performance conditions that affect vesting to account for such awards. The amendments in ASU 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Early adoption is permitted. Entities may apply the amendments in ASU 2014-12 either: (a) prospectively to all awards granted or modified after the effective date; or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The adoption of ASU 2014-12 is not expected to have a material effect on the Company's consolidated financial statements or disclosures.

In April 2014, the FASB issued ASU 2014-08, "Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360): Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity." ASU 2014-08 changes the criteria for reporting a discontinued operation. Under the new pronouncement, a disposal of a part of an organization that has a major effect on its operations and financial results is a discontinued operation. The Company is required to adopt ASU 2014-08 prospectively for all disposals or components of its business classified as held for sale during fiscal periods beginning after December 15, 2014. The adoption of ASU 2014-08 is not expected to have a material effect on the Company's consolidated financial statements or disclosures.

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers" ("ASU 2014-09"), which provides guidance for revenue recognition. ASU 2014-09 affects any entity that either enters into contracts with customers to transfer goods or services or enters into contracts for the transfer of nonfinancial assets and supersedes the revenue recognition requirements in Topic 605, "Revenue Recognition," and most industry-specific guidance. This ASU also supersedes some cost guidance included in Subtopic 605-35, "Revenue Recognition- Construction-Type and Production-Type Contracts." ASU 2014-09's core principle is that a company will recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration to which a company expects to be entitled in exchange for those goods or services. In doing so, companies will need to use more judgment and make more estimates than under today's guidance, including identifying performance obligations in the contract, estimating the amount of variable consideration to include in the transaction price and allocating the transaction price to each separate performance obligation. ASU 2014-09 is effective for the Company beginning January 1, 2017 and, at that time, the Company may adopt the new standard under the full retrospective approach or the modified retrospective approach. Early adoption is not permitted. The Company is currently evaluating the method and impact the adoption of ASU 2014-09 will have on the Company's consolidated financial statements and disclosures.

In August 2014, the FASB issued ASU No. 2014-15, *Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern* ("ASU 2014-15"). ASU 2014-15 will explicitly require management to assess an entity's ability to continue as a going concern, and to provide related footnote disclosure in certain circumstances. The new standard will be effective for all entities in the first annual period ending after December 15, 2016. Earlier adoption is permitted. We are currently evaluating the impact of the adoption of ASU 2014-15.

Other accounting standards that have been issued or proposed by the FASB, or other standards-setting bodies, that do not require adoption until a future date are not expected to have a material impact on the Company's financial statements upon adoption.

3. Acquisitions and Dispositions of Oil and Gas Properties

Acquisitions

On May 25, 2011, the Company entered into a Purchase and Sale Agreement and other related agreements and documents with Tucker Family Investments, LLLP; DNR Oil & Gas, Inc. ("DNR"); and Tindall Operating Company (collectively, the "Sellers") for the purchase of certain oil and gas operating properties in Colorado, Kansas, Wyoming, and Montana (collectively, the "Original Purchase and Sale Agreement"). DNR is principally owned by an officer and director of the Company, Charles B. Davis. The consideration for the purchase was determined by bargaining between management of the Company and Sellers, and the Company used reports of independent engineering firms to analyze the purchase price. The base purchase price for the properties was $10.0 million, of which the Company paid a nonrefundable down payment of $0.5 million and the remaining $9.5 million was financed by the Sellers pursuant to a promissory note due on July 1, 2011. The Company was unable to arrange the funding to pay the $9.5 million promissory note due on July 1, 2011, and therefore, the note was not paid.

On July 29, 2011, the Company and Sellers entered into an Amended and Restated Purchase and Sale Agreement ("PSA") regarding the purchase of (i) working interests in oil and gas properties located in Wyoming, Colorado, Kansas and Montana (the "Properties"), and (ii) vested contractual rights in the net proceeds from the future sale of certain properties located in Wyoming (the "Separate Interests"). The material terms of the PSA included an aggregate base purchase price for the Properties and the Separate Interests of $11.0 million to be paid by an initial payment of $0.9 million, comprised of (i) a credit in the amount of $0.5 million previously paid by the Company in connection with the Original Purchase and Sale Agreement; and (ii) $0.4 million in funds paid contemporaneously with the execution of the PSA. The remaining principal balance of the base purchase price in the amount of $10.1 million, together with interest at 10% per annum, was payable to Sellers in three monthly payments, with $3.7 million due August 15, 2011 (extended to August 31, 2011), and $3.2 million due on each of September 15, 2011 and October 15, 2011. By September 29, 2011, all required consideration had been paid to Sellers and closing of the PSA was completed.

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The PSA provided that the Company was entitled to the Properties' oil and gas production and sales proceeds beginning on April 1, 2011, and the Company was also responsible for the lease operating expenses of the Properties beginning on April 1, 2011. The net proceeds from oil and gas sales, less production taxes and lease operating expenses from April 1, 2011 to July 29, 2011 amounted to $766,728, which was treated as a reduction of the carrying cost of the Properties.

The acquisition of the Properties was structured such that the Company acquired 100% of Seller's interest in certain geologic zones of the properties. Presented below is a summary of agreed-upon values associated with the Properties and the Separate Interests, along with a discussion of the interests in the Properties retained by the Sellers:

Properties:	
Rex Lake/ Big Hollow (WY)	$ 511,025***(b)***
Kansas	2,152,216***(a)***
Montana	98,179***(b)***
Wyoming	2,733,773***(b)***
Buff (WY)	611,211***(b)***
Colorado	2,507,678***(a)***
Total Working Interest Properties	8,614,802
Separate Interests	2,385,918***(d)***
	$11,000,000***(c)***

(a) For a period of ten years after the closing date, the Colorado and Kansas properties provide for additional consideration that is payable to Sellers based on increases in Nymex prices for oil and natural gas, without regard to changes in the Company's oil and natural gas reserves (referred to as the "Price Increase Factor"). If Nymex thresholds of $90, $100, $110, $125 and $150 per barrel of oil are exceeded for periods of 61 consecutive days, incremental purchase consideration of $250,000, $250,000, $500,000, $500,000 and $2,000,000, respectively, will be payable to Sellers. Similarly, if Nymex thresholds of $5.00, $6.00, $7.50, $10.00 and $12.00 per MMbtu of natural gas are exceeded for periods of 61 consecutive days, incremental purchase consideration of $50,000, $50,000, $150,000, $250,000 and $250,000, respectively, will be payable to Sellers.

The Colorado and Kansas properties also provide for additional consideration that is payable to Sellers if reserves classified as "possible" are converted to "proved producing reserves" through drilling or recompletion activities over a period of ten years after the closing date (referred to as the "Possible Reserve Factor"). For such increases in oil reserves, the Sellers are entitled to additional consideration of $250,000 for each increase of 20,000 net barrels; and for such increases in natural gas reserves, the Sellers are entitled to additional consideration of $150,000 for each increase of 150,000 mcf of natural gas.

The Possible Reserve Factor also requires a multiplier effect from 1 to 5 depending on the Price Increase Factor that is effective when the proved producing reserves are obtained. For example, the Possible Reserve Factor consideration would be multiplied by 2 if the oil Price Increase Factor of $100 is in effect when the proved producing reserves are confirmed. Similarly, the Possible Reserve Factor consideration would be multiplied by 2 if a natural gas Price Increase Factor of $6.00 per MMbtu is in effect when the proved producing natural gas reserves are confirmed. The maximum increase in purchase price for the Kansas and Colorado properties is limited to $5 million.

(b) Additional consideration is also payable for the properties located in Wyoming to the extent that the Company increases proved producing reserves through future drilling or recompletion activities in formations that are not producing as of the closing date under the Possible Reserve Factor. Similar to the properties in Colorado and Kansas, the Possible Reserve Factor will be multiplied by a factor of 1 to 5 depending on the Price Increase Factor that is effective when the proved producing reserves are obtained.

Furthermore, if the Company sells any of the properties in Wyoming, the Sellers have retained an interest of 70% in the net sales proceeds (after the Company receives a recovery of 125% of the original agreed-upon allocation as contained in the table above).

The maximum increase in purchase price (including Sellers retained interest of 70% for the Wyoming properties discussed in the preceding paragraph) for all properties in all states shown in the table above is limited to $25 million. Due to the sale of the Separate Interests discussed below, accrual of $500,000 due to a sustained increase in oil prices over $90 and $100 per barrel, the sale of a second property in February 2012 and a the sale of a third property in 2013 , the maximum future consideration has been reduced by approximately $5.8 million to $19.2 million.

(c) Note that the values shown in this table are the allocation amounts attributable to the proved developed zones agreed to between the Company and the Sellers, before purchase adjustments for pre-acquisition net revenues received, oil in tanks and contingent purchase price adjustments. These adjustments do not modify the agreed upon value for purposes of the adjustments discussed above but will affect the final purchase allocation under generally accepted accounting principles.

(d) With respect to the Separate Interests, a formal closing and transfer of title was not required, and did not occur, in order for the Company to realize its proceeds related to the sale of the Separate Interests. The Company acquired the contractual rights associated with the Separate Interests on July 29, 2011, and the Company's share of the net proceeds of $5,101,047 was received on August 23, 2011, which resulted in recognition of a non-operating gain in the third quarter of 2011 of $2,479,934. The Company applied the $5,101,047 of net proceeds to the payments due under the PSA.

Property Dispositions

The Company also had an agreement for the right to receive a portion of the proceeds from sale of certain of the properties that could be sold before payment in full of the base purchase price and assignment of the properties to the Company. The School Creek properties were sold on August 23, 2011 and the Company received $5,101,047 for its share of the proceeds on the sale, which resulted in a gain on sale of $2,479,934. The Company applied the proceeds to the payments due under the purchase and sale agreement. On September 29, 2011 the Company paid the balance of $5,120,194 that included $121,241 of interest. The Company as part of the agreement received the production of oil and gas from April 1, 2011 and was responsible was the lease operating expenses for that period. The net proceeds of the production, production taxes, and lease operating expenses from April 1, 2011 to July 29, 2011 of $766,812 was applied to the carrying costs of the oil and natural gas properties.

In February 2012, the Company sold to an unaffiliated party a working interest in a well and related lease in Niobrara County, Wyoming for gross proceeds of approximately $1,109,000. After payment of additional consideration pursuant to the formula discussed under (b) in the acquisition table above, the Company realized net proceeds of $826,000. The purchaser assumed the asset retirement obligations estimated at approximately $16,000 and after deducting the net book value of the property, the Company recognized a gain on sale of $533,048. The Company retained a 2.575% overriding royalty interest in this property. This sale comprised approximately 1.6% of the Company's barrels of oil equivalent ("BOE") of oil and gas reserve quantities, and approximately 2.2% of the Company's discounted future net revenues prior to the sale. The Company determined that this sale did not qualify for discontinued operations reporting.

In December 2013, we sold one of our producing properties, which resulted in gross proceeds of approximately $1,004,000. This property was sold to an unrelated purchaser and pursuant to our amended purchase agreement entered into in September 2013, we were required to pay the related party sellers approximately $554,000 of the proceeds due to their contingent interest and, as a result our net proceeds were $450,000. After deducting the net book value of the property of $163,000, plus the asset retirement obligation assumed by the unrelated purchaser of $31,000, we recognized a gain of approximately $318,000. The Company retained a 1.57% overriding royalty interest in this property. This sale comprised approximately 1.1% of the Company's barrels of oil equivalent ("BOE") of oil and gas reserve quantities, and approximately 2.2% of the Company's discounted future net revenues prior to the sale. The Company determined that this sale did not qualify for discontinued operations reporting.

4. Stockholders' Equity

Common Stock

As of December 31, 2012, the Company has a liability for directors' fees of $33,615 which was a issuance of 64,556 shares of common stock in 2013. Additionally, the Company has a liability for accrued consulting fees of $29,550 that resulted in the issuance of 85,000 shares of common stock in 2013.

During the year ended December 31, 2013, the Company issued 85,000 shares of common stock for payment of fees accrued to consultants. The Company issued 44,823 shares of common stock for payment of fees accrued to related party consultants. During 2013 the Company issued 72,170 shares of common stock for payment of accrued directors fees for the period July 1, 2012 to November 30, 2013.

Effective June 28, 2013, several holders of the Company's 15% Series A1 Convertible Preferred Stock ("Series A1 Preferred Stock") elected to convert shares of such stock into the Company's common stock at a redemption price of $0.75 per common share. In connection with those redemptions all such holders agreed to waive all dividend rights on their shares of Series A1 Preferred Stock subsequent to March 30, 2013. Information regarding the conversions is set forth below.

Name of Holder	Number of Shares of Series A1 Preferred Stock Converted	Number of Common Shares Issued
Burlingame Equity Investors II, LP	16	100,800
Burlingame Equity Investors Master Fund, LP	184	1,159,200
Charles B. Davis*	100	1,333,333
Tucker Family Investments LLLP	25	333,333
Mark Venjohn	10	133,333
Pete Haman	35	466,667
Nicholas L. Scheidt*	100	1,333,333
Michael J. Finney	5	66,667
William and Sara Kroske	2.5	33,333
Michael A. Geller	10	133,333
John H. Rosasco	10	133,333
Lyon Oil & Gas Company	10	133,333
T P Furlong	5	66,667

* Executive Officer and Director of the Company

In addition, in connection with the conversions of Series A1 Preferred Stock by Burlingame Equity Investors II, LP and Burlingame Equity Investors Master Fund, LP, the Company also entered into transactions with these entities in exchange for cash consideration, promissory notes and cancellation of certain Series A1 Preferred Shares.

Name of Holder	Cash Consideration	Promissory Note–Principal	Series A1 Preferred Shares Cancelled
Burlingame Equity Investors II, LP	$ 4,000	$ 48,000	16
Burlingame Equity Investors Master Fund, LP	$ 46,000	$ 552,000	184

The above promissory notes bear interest at 7% per annum, with interest payable quarterly and all unpaid interest and principal due on July 23, 2014 and the note has been extended to April 28, 2015. If the promissory notes are not paid when due or declared due, the entire principal and interest thereon will bear interest at the rate of 12% per annum (see note 5).

The redemption of preferred stock on the earning per share applicable to common stockholders was calculated as the difference between the fair market value of common shares received on June 28, 2013 and the cost of the preferred stock redeemed which amounted to $3,160,026.

On August 15, 2014, the remaining preferred shareholders made an agreement with The Company to redeem his 10 shares of Series A-1 Convertible Preferred Stock. The Company paid $77,500 for the shares as follows; $15,500 in cash and a promissory note for $62,000.

On December 10, 2013, Burlingame Equity Investors Master Fund LP ("Burlingame"), a significant stockholder of Arête Industries, Inc. (the "Company") entered into conditional stock option agreements with Nicholas L. Scheidt, the Company's Chief Executive Officer and Director, pursuant to which Mr. Scheidt was granted options to purchase up to 1,460,000 shares of Company common stock at $0.19 per share. Mr. Scheidt subsequently assigned the right to purchase 1,200,000 shares to the Company on January 27, 2014. On January 30, 2014, the Company entered into a Direct Stock Purchase Agreement with Burlingame pursuant to which the Company has purchased the 1,200,000 shares of its common stock from Burlingame at a price of $0.19 per share for total consideration of $228,000. In addition, Mr. Scheidt assigned an additional 141,873 shares of Company common stock underlying his option from Burlingame to Donald W. Prosser, the Company's Chief Financial Officer and Director. Pursuant to this assignment, Mr. Prosser agreed to purchase the entire 141,873 shares of Company common stock from Burlingame at a price of US $0.19 per share for total consideration of $26,956. Furthermore, of these 141,873 shares, Mr. Prosser agreed to transfer 57,895 shares to William W. Stewart, a Director of the Company, for $11,000 or $0.19 per share and 13,158 shares to Apex Financial Services Corp, a company controlled by Mr. Scheidt, for $2,500 or $0.19 per share. Finally, Mr. Scheidt agreed to exercise the remaining 118,127 shares of Company common stock under his option from Burlingame at a price of $0.19 per share for total consideration of $22,444.

The Company purchased an option to acquire rights in minerals owned by William W Stewart (related party) for 150,000 shares of common stock valued at $34,500.

Preferred Stock Dividends

Preferred stock dividends are payable semi-annually in cash or shares of the Company's common stock, at the election of the Company. The Board of Directors declared the preferred dividend of $391,875 on April 26, 2013 and paid the dividend in cash on April 28, 2013.

Preferred Stock

On September 29, 2011, the Company completed a private placement of its Preferred Stock Series A1 which resulted in the issuance of 522.5 shares for gross proceeds of $5,225,000. The balance of the Preferred Stock Series 1-A at December 31, 2014 and was $ 0 as all shares have been redeemed or canceled.

The following are the terms of the Preferred Stock Series A1:

Authorized Shares, Stated Value and Liquidation Preference. Seven hundred fifty shares are designated as the Series A1 15% Convertible Preferred Stock, which has a stated value and liquidation preference of $10,000 per share plus accrued and unpaid dividends.

Ranking. The Series A1 Preferred Stock will rank senior to future classes or series of preferred stock established after the issue date of the Series A1 Preferred Stock, unless the Company's Board of Directors expressly provides otherwise when establishing a future class or series. The Series A1 Preferred Stock ranks senior to the Company's common stock in liquidation and dissolution.

Dividends. Holders of Series A1 Preferred Stock are entitled to receive, when, as and if declared by the Board of Directors, non-cumulative dividends at an annual rate of 15.0% of the $10,000 per share stated value. Declared dividends are payable in cash or in shares of Common Stock (at its then fair market value), at the election of the Company.

Voting Rights. The holders of the Series A1 Preferred Stock will vote together with the holders of common stock as a single class on all matters upon which the holders of common stock are entitled to vote, except that the common stock will elect four directors and the Series A1 Preferred Stock will elect three directors. Each share of Series A Preferred Stock will be entitled to such number of votes as the number of shares of common stock into which such share of Preferred Stock is convertible; however, solely for the purpose of determining such number of votes, the conversion price per share will be deemed to be $3.30, subject to customary anti-dilution adjustment. In addition, the holders of the Series A1 Preferred Stock will vote as a separate class with respect to certain matters, including amendments to the Company's Articles of Incorporation that alter the voting powers, preferences and special rights of the Series A1 Preferred Stock.

Liquidation. In the event we voluntarily or involuntarily liquidate, dissolve or wind up, the holders of the Series A1 Preferred Stock will be entitled, before any distribution or payment out of the Company's assets may be made to or set aside for the holders of any junior capital stock and subject to the rights of creditors, to receive a liquidation distribution in an amount equal to $10,000 per share, plus any accrued but unpaid dividends. A merger, consolidation or sale of all or substantially all of the Company's property or business is not deemed to be a liquidation for purposes of the preceding sentence.

Redemption. The Series A1 Preferred Stock is redeemable in whole or in part at the Company's option at any time. The redemption price is equal to $10,000 per share, plus any accrued but unpaid dividends.

Preemptive Rights. Holders of the Series A1 Preferred Stock do not have preemptive rights to purchase securities of the Company.

Mandatory Conversion. Each share of Series A1 Preferred Stock remaining outstanding will automatically be converted into shares of our common stock upon the earlier of (i) any closing of underwritten offering by the Company of shares of Common Stock to the public pursuant to an effective registration statement under the Securities Act of 1933, in which the aggregate cash proceeds to be received by the Company and selling stockholders (if any) from such offering (without deducting underwriting discounts, expenses and commissions) are at least $15,000,000, and the price per share paid by the public for such shares is at least $3.30 (such price to be adjusted for any stock dividends, combinations or splits or (ii) the date agreed to by written consent of the holders of a majority of the outstanding Series A1 Preferred Stock.

Optional Conversion by Investors. At any time, each holder of Series A1 Preferred Stock has the right, at such holder's option, to convert all or any portion of such holder's Series A1 Preferred Stock into shares of common stock prior to the mandatory conversion of the Series A1 Preferred Stock at a price of $3.30 per share.

Optional Conversion by the Company. If the closing price of the Company's common stock on the Trading Market is $4.50 or more for 20 consecutive trading days, then up to 25% of the outstanding stated value of the Series A1 Preferred Stock, plus any accrued and unpaid dividends, will be subject to conversion into Company common stock at the option of the Company. For each successive period that the closing price of the common stock is at least $4.50 for a period of 20 consecutive trading days beyond the first 20 day period, the Company will have the right to convert another 25% of the outstanding Series A1 Preferred Stock, such that if the closing price of the common stock is at least $4.50 for 80 consecutive trading days, then all of the outstanding shares of Series A1 Preferred Stock may be converted into common stock at the Company's option.

Conversion Price. Each share of Series A1 Preferred Stock is convertible into shares of common stock at a conversion price of $3.30 per share, subject to customary anti-dilution adjustments, including in connection with stock dividends and distributions, stock splits, subdivisions and combinations.

Redemption by Holder. Unless prohibited by Colorado law, upon 90 days' prior written request from any holders of outstanding shares of Series A1 Preferred Stock, the Company may at its discretion, redeem at a redemption price equal to the sum of (i) $10,000 per share and (ii) the accrued and unpaid dividends thereon, to the redemption date, up to one-third of each holder's outstanding shares of Series A1 Preferred Stock on: (i) the first anniversary of the Original Issuance Date (the "First Redemption Date"), (ii) the second anniversary of the Original Issue Date (the "Second Redemption Date") and (iii) the third anniversary of the Original Issue Date (the "Third Redemption Date", along with the First Redemption Date and the Second Redemption Date, collectively, each a "Redemption Date"). The redemption price for any shares of Series A1 Preferred Stock shall be payable on the redemption date to the holder of such shares against surrender of the certificate(s) evidencing such shares to the Corporation or its agent. The Company may instead at its option, reduce the applicable conversion price by 50% with respect to the shares of preferred stock for which redemption has been requested.

5. Notes and advances payable

Notes payable consist of the following as of December 31, 2013 and 2014:

	2013	2014
Officers, directors and affiliates:		
Notes and advances payable, interest at 8.0%, due on demand	$ 14,984	$ —
Notes and advances payable, interest at 9.7%, due on demand	85,000	—
Note payable, interest at 7.5%, due March 2015 Extended to March 2016	150,000	150,000
Notes payable, interest 7.0%, due January 2017	—	79,970
Notes payable, interest varies (see explanation below)	792,151	792,151
Collateralized note payable (see below)	714,488	120,728
Total officers, directors and affiliates	1,756,623	1,142,849
Less: Current portion of officers, directors, and affiliates	717,833	288,258
Long-term portion of officers, directors, and affiliates	$1,038,790	$ 854,591
Unrelated parties:		
Notes payable, interest at 7.5%, due March 2015 Extended to March 2016	200,000	100,000
Note payable, interest variable (see below)	—	549,105
Note payable, interest at 7.0%, due August 2016	—	62,000
Notes payable, interest at 7.0%, due January 2017	—	41,668
Notes payable, interest at 7.0%, due April 2015	550,000	183,000
Total unrelated parties	750,000	935,773
Less: Current portion of unrelated parties	325,000	872,239
Long-term portion of unrelated parties	$ 425,000	$ 63,534

On April 29, 2013, the Company executed a promissory note under which the Company agreed to pay Apex Financial Services Corp, a Colorado corporation, ("Apex") the principal sum of $1,000,000, with interest accruing at an annual rate of 7.5%, with principal and interest due on May 31, 2014 paid and renewed to March 31, 2016. The Company also agreed to assign 75% of its operating income from its oil and gas operations and any lease or well sale or any other assets sales to Apex to secure the debt. Apex is 100% owned by the CEO, director, and shareholder of the Company, Nicholas L. Scheidt. The Company borrowed the full amount of principal on the note, and also paid a loan fee of $10,000. In the event of default on the note and failure to cure the default in ten days, Apex may accelerate payment and the annual interest rate on the note will accrue at 18%. Default includes failure to pay the note when due or if the Company borrows any other monies or offers security in the Company or in the collateral securing the note prior to the note being paid in full. The outstanding principal balance as of December 31, 2014 was $120,728.

On January 28, 2014, we entered into a line of credit loan agreement for $1,500,000 due January 15, 2015 extended to April 28, 2015. The terms of the note are as follows: 1) the accrued interest is payable monthly starting February 28, 2014, 2) the interest rate is variable based on an index calculated based on a prime rate as published by the Wall Street Journal index (currently 3.25%) plus an add on index with the current and minimum rate of 6.5%., the note has draw provisions, with the first draw of $479,701 4) the note is secured by seven wells and leases owned by the Company, a certificate of deposit for $500,000 at CityWide Bank pledged by a related party, and 5) the personal guarantee of the Nicholas Scheidt, Chief Executive Officer. The amount eligible for borrowing on the Credit Facility is limited to the lesser of (i) 65% of the Company's PV10 value of its carbon reserves based upon the most current engineering reserve report or (ii) 48 month cumulative cash flow based upon the most current engineering reserve report. In addition to the borrowing base limitation, the Company is required to maintain and meet certain affirmative and negative covenants and conditions in order to draw advances on the Credit Facility. The Credit Facility contains certain representations, warranties, and affirmative and negative covenants applicable to the Company, which are customarily applicable to senior secured loan facilities. Key covenants include limitations on indebtedness, restricted payments, creation of liens on oil and gas properties, hedging transactions, mergers and consolidations, sales of assets, use of loan proceeds, change in business, and change in control. The above-referenced promissory notes contain customary default and acceleration provisions and provide for a default interest rate of 21% per annum. In addition, the Credit Facility contains customary events of default, including: (a) failure to pay any obligations when due; (b) failure to comply with certain restrictive covenants; (c) false or misleading representations or warranties; (d) defaults of other indebtedness; (e) specified events of bankruptcy, insolvency or similar proceedings; (f) one or more final, non-appealable judgments in excess of $50,000 that is not covered by insurance; (g) change in control (25% threshold); (h) negative events affecting the Guarantor; and (i) lender in good faith believes itself insecure. In an event of default arising from the specified events, the Credit Facility provides that the commitments thereunder will terminate and the Lender may take such other actions as permitted including, declaring any principal and accrued interest owed on the line of credit to become immediately due and payable. The Credit Facility is secured by a security interest in substantially all of the assets of the Company, pursuant to a Security Agreement, Deed of Trust and Assignment of As-Extracted Collateral entered into between the Company and Citywide Banks. The outstanding principal balance as of December 31, 2014 was $549,105.

On January 1, 2014, we memorialized our short-term liabilities into formal promissory notes. These certain outstanding advances and other notes payable are now included in single promissory notes, all have been reported previously in our financial statements. Information concerning these promissory notes is set forth in the table below.

Name of Holder	Position	Principal Amount	Interest Rate	Monthly P&I Payment Amount	Number of Monthly Payments
Donald W. Prosser	CFO & Director	$28,500	7.00%	$564.33	60
Charles B. Davis	COO & Director	$66,500	7.00%	$1,316.78	60
William Stewart	Director	$49,500	7.00%	$980.16	36
Sold to an unrelated party					

The above-referenced promissory notes contain customary default and acceleration provisions and provide for a default interest rate of 18% per annum. The outstanding principal balances as of December 31, 2014 was $79,970.

In addition, we also issued an unsecured promissory note in the amount of $792,151 on January 1, 2014 to DNR Oil & Gas, Inc. ("DNR"). DNR is a company controlled by one of our directors, Charles B. Davis. The DNR note accrues interest at the rate of 2.50% for the calendar years 2014 and 2015, 4.00% for the calendar year 2016, 6.00% for the calendar year 2017 and 8.00% for the remainder of the term of the DNR note. The DNR note matures on January 1, 2019. The DNR note requires payments as follows:

- One payment of $250,000 in 2016;
- One payment of $250,000 in 2017;
- One payment of $250,000 in 2018; and
- The balance of principal and accrued interest on or before January 1, 2019.

The DNR note contains customary default and acceleration provisions and provides for a default interest rate of 18% per annum. The note is subordinated to the Bank Line of Credit. The outstanding principal balance as of December 31, 2014 was $792,151.

In June 2013, in connection with the conversions of Series A1 Preferred Stock by Burlingame Equity Investors II, LP and Burlingame Equity Investors Master Fund, LP, the Company issued unsecured promissory notes in the original principal amounts of $48,000 and $552,000, respectively, with interest at 7% per annum payable quarterly and all unpaid interest and principal due on July 23, 2014. In connection with our new line of credit, we have agreed with the holders of these two existing notes to make a partial prepayment on the principal balance of the Notes in exchange for an extension of the maturity date to April 28, 2015. Information concerning the principal pay down and new maturity date is set forth in the following table.

Name of Holder	Principal Balance Before Pay down	Principal Pay down	Remaining Principal Balance
Burlingame Equity Investors II, LP	$ 44,000	$ 26,251	$ 17,749
Burlingame Equity Investors Master Fund, LP	$ 506,000	$ 340,749	$ 165,251

On August 15, 2014 the Company executed a Promissory Note to an individual for the redemption of 10 shares of Series A-1 Preferred Stock. The terms of the Promissory Note are as follows: $62,000 with an interest rate of 7% payable in two payments of $31,000 each plus interest, due August 15, 2015 and August 15, 2016 respectively.

All of the notes payable shown above are unsecured, except the Apex note. Accrued interest on notes and advances payable amounted to $52,242 as of December 31, 2013 and $3,279 as of December 31, 2014.

6. Contracts Payable

The Company entered into a consulting contract for financing, structure, and investor services on March 2, 2010 for 800,000 shares of Common Stock valued at $500,000. The contract was for a period of three years and the fair value of the services were amortized ratably over the service period. Accordingly, the Company recognized a charge to investor relations expense of $27,778 and $0 for the year ended December 31, 2013 and 2014, respectively.

7. General and Administrative Expenses

In connection with the property acquisition agreement entered into in the third quarter of 2011, the Company executed an operating agreement whereby DNR provides services to operate all of the properties acquired by the Company for a monthly fee of $23,000. The operating agreement expired on March 31, 2012 and renews on a month to month basis.

Based on operator costs for the properties prior to the Company's acquisition, approximately $8,000 per month is included in lease operating expenses and $15,000 per month is included in related party consulting fees in the accompanying Consolidated Statements of Operations. Effective July 1, 2012, the monthly operator fee was reduced to $18,000 per month, of which $8,000 per month is included in lease operating expense and the remaining $10,000 per month is included in related party consulting fees.

Presented below is a summary of general and administrative expenses for the years ended December 31, 2013 and 2014:

	2013	2014	Change
Director fees	$ 2,250	$ 20,450	$ 18,200
Investor relations	98,505	65,833	(32,672)
Legal, auditing and professional services	147,348	146,581	(767)
Consulting and executive services:			
Related parties	123,000	220,800	97,800
Unrelated parties	—	—	—
Other administrative expenses	59,712	72,807	13,095
Depreciation	570	570	—
Total general and administrative expenses	$431,485	$527,041	$ 95,656

General and administrative expenses increased by $95,656 for 2014 compared to 2014, primarily due to decreases in investor relations and legal, auditing and professional fees; and increases in consulting and executive services, directors fees, and other administrative expenses.

8. Income Taxes

At December 31, 2014, the Company has net operating loss ("NOL") carryforwards for Federal income tax purposes of approximately $7,900,000. If not previously utilized, the NOL carryforwards will expire in 2018 through 2030.

For the years ended December 31, 2013 and 2014, the Company did not recognize any current or deferred income tax benefit or expense. Actual income tax benefit (expense) for the years ended December 31, 2013 and 2014 differs from the amounts computed using the federal statutory tax rate of 34%, as follows:

	2013	2014
Income tax benefit (expense) at the statutory rate	$(152,000)	$(21,000)
Benefit (expense) resulting from:		
Increase in Federal valuation allowance	152,000	—
Utilization of net operating loss carryforwards	—	21,000
Income tax benefit (expense)	$ —	$ —

At December 31, 2013 and 2014, the tax effects of temporary differences that give rise to significant deferred tax assets and liabilities are presented below:

	2013	2014
Federal net operating loss carryforwards	$ 2,677,000	$ 2,465,000
State net operating loss carryforwards	268,000	264,000
Oil and gas properties	(222,000)	(222,000)
Asset retirement obligations	241,000	241,000
Net deferred tax assets	2,964,000	2,748,000
Less valuation allowance	(2,964,000)	(2,748,000)
Net deferred tax assets	$ —	$ —

A valuation allowance has been recorded for all deferred tax assets since the “more likely than not” realization criterion was not met as of December 31, 2013 and 2014.

A tax benefit from an uncertain tax position may be recognized if it is “more likely than not” that the position is sustainable based solely on its technical merits. For the years ended December 31, 2013 and 2014, the Company had no unrecognized tax benefits and management is not aware of any issues that would cause a significant increase to the amount of unrecognized tax benefits within the next year. The Company’s policy is to recognize any interest or penalties as a component of income tax expense. The Company’s material taxing jurisdictions are comprised of the U.S. federal jurisdiction and the states of Colorado, Wyoming and Kansas. The tax years 2009 through 2014 remain open to examination by these taxing jurisdictions.

9. Asset Retirement Obligations

The Company follows accounting for asset retirement obligations (“ARO”) in accordance with ASC 410, *Asset Retirement and Environmental Obligations*, which requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it was incurred if a reasonable estimate of fair value can be made. The Company’s ARO primarily represents the estimated present value of the amounts expected to be incurred to plug, abandon and remediate producing and shut-in wells at the end of their productive lives in accordance with applicable state and federal laws. The Company determines the estimated fair value of its ARO by calculating the present value of estimated cash flows related to plugging and abandonment liabilities. The significant inputs used to calculate such liabilities include estimates of costs to be incurred, the Company’s credit adjusted discount rates, inflation rates and estimated dates of abandonment. The ARO is accreted to its present value each period and the capitalized asset retirement costs are amortized using the unit of production method.

A reconciliation of the Company’s ARO for the years ended December 31, 2013 and 2014 is as follows:

	2013	2014
Balance, beginning of year	$ 647,268	$ 682,203
Liabilities incurred upon acquisition of properties	—	—
Liabilities assumed by buyer of properties	(32,161)	—
Liabilities settled	—	—
Accretion expense	67,096	66,810
Revisions of prior estimates	—	—
Balance, end of year	682,203	749,013
Less current asset retirement obligations	(159,782)	(191,843)
Long-term asset retirement obligations	$ 522,421	$ 557,170

10. Commitments and Contingencies

Lease commitments. The Company entered into a lease for property access rights and compressor space in Wyoming related to the Company’s natural gas gathering system. The expense in 2013 and 2014 was approximately $9,600, which is included in gas gathering operating costs. The Company uses office space and conference room space provided by a director for an annual charge of $3,000 for the years ended December 31, 2013 and 2014.

Legal Proceedings. The Company is subject to the risk of litigation, claims and assessments that may arise in the ordinary course of its business activities, including contractual matters and regulatory proceedings. As of December 31, 2014, the Company was not subject to any pending litigation and management is not currently aware of any asserted or unasserted claims and assessments that may impact the Company’s future results of operations.

11. Business and Credit Concentrations

Concentrations of Market Risk. The future results of the Company’s oil and gas operations will be affected by the market prices of oil and gas. A readily available market for crude oil, natural gas and liquid products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of oil, gas and liquid products, the regulatory environment, the economic environment and other regional and political events, none of which can be predicted with certainty.

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The Company operates in the exploration, development and production phase of the oil and gas industry. Its receivables include amounts due from DNR, a related party that operates the Company's oil and gas properties and collects remittances from the purchasers of the Company's oil and natural gas. The Company believes that no single customer or joint venture partner exposes the Company to significant credit risk. While certain of these customers and joint venture partners are affected by periodic downturns in the economy in general or in their specific segment of the natural gas or oil industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations in the long-term. Trade receivables are not collateralized.

Concentrations of Credit Risk. The Company maintains its cash in bank accounts that, at times, may exceed federally insured limits. During the years ended December 31, 2013 and 2014, the Company had balances that exceeded the $250,000 federally insured limit.

12. Subsequent Events

The following are the subsequent events:

During the 1st quarter 2015 the Company extended all of its notes due during that period. The following are the details of the extensions:

Fairfield Management Company extended to March 31, 2016
Apex Financial Services Corporation extended to March 31, 2016
Pikerni LLC extended to March 31, 2016
Burlingame Equity Investors II, LP extended to April 28, 2016 (reviewing a longer term)
CityWide Bank extended to April 28, 2015 longer extension pending the review of the reserve study and 10K 2014

13. Supplementary Oil and Gas Information (unaudited)

Costs Incurred in Oil and Gas Producing Activities

Costs incurred in oil and gas property acquisition, exploration and development activities and related depletion, depreciation, amortization and accretion ("DD&A") per equivalent unit-of-production were as follows for the years ended December 31, 2013 and 2014:

	2013	2014
Acquisition costs:		
Unproved properties	$ —	$ 34,500
Proved properties	—	—
Exploration costs	—	—
Development costs	307,834	594,359
Revisions to asset retirement obligation	34,934	—
Total costs incurred	$342,768	$628,859
Depletion per BOE of production	$ 19.01	$ 22.24

Supplemental Oil and Gas Reserve Information

The reserve information presented below is based on estimates of net proved reserves as of December 31, 2012 and 2013 that were prepared by Ryder Scott Company, the Company's independent petroleum engineering firm, in accordance with guidelines established by the SEC.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Changes in Proved Reserves

The Company did not have any proved reserves prior to 2011. The following table sets forth information regarding the Company's estimated total proved and oil and gas reserve quantities for the years ended December 31, 2013 and 2014:

	Oil (Bbl)	Gas (Mcf)	Equivalent (BOE)
Balance, December 31, 2012	331,672	529,239	419,879
Sale of oil and gas reserves in place	(4,080)	—	(4,080)
Revisions in previous estimates	(60,081)	233,116	(18,229)
Production	(20,517)	(85,567)	(37,778)
Balance, December 31, 2013	246,994	676,788	359,792
Revisions in previous estimates	13,060	8,347	14,452
Production	(22,825)	(70,195)	(34,524)
Balance, December 31, 2014	237,229	614,940	339,720
Proved reserves, December 31, 2013:			
Proved developed	184,349	668,489	295,764
Proved undeveloped	62,645	8,299	64,028
Proved reserves, December 31, 2014:			
Proved developed	230,530	614,940	333,020
Proved undeveloped	6,699		6,699

Standardized Measure

Certain information concerning the assumptions used in computing the valuation of proved reserves and their inherent limitations are discussed below. The Company believes such information is essential for a proper understanding and assessment of the data presented.

As of December 31, 2013, future cash inflows were computed by applying the SEC-mandated 12 month arithmetic average of the first of month price for January through December of 2013, which resulted in benchmark prices of $96.78 per barrel for crude oil and $3.67 per MMbtu for natural gas. Prices were further adjusted for transportation, quality and basis differentials, which resulted in an average price used as of December 31, 2013 of $87.49 per barrel of oil and $5.86 per Mcf for natural gas.

As of December 31, 2014, future cash inflows were computed by applying the SEC-mandated 12 month arithmetic average of the first of month price for January through December of 2014, which resulted in benchmark prices of $94.99 per barrel for crude oil and $4.35 per MMbtu for natural gas. Prices were further adjusted for transportation, quality and basis differentials, which resulted in an average price used as of December 31, 2014 of $84.09 per barrel of oil and $6.09 per Mcf for natural gas.

The assumptions used to compute estimated future cash inflows do not necessarily reflect the Company's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Company's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. However, if reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

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Future development and production costs are 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.

Future income tax expenses are computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the Company's proved oil and gas reserves. Net operating losses incurred in oil and gas producing activities are utilized to reduce taxable income. Permanent differences in oil and gas related tax credits and allowances are recognized, if reasonably estimable.

A 10% annual discount rate was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves. The following table presents the standardized measure of discounted future net cash flows related to proved oil and gas reserves as of December 31, 2013 and 2014:

	2013	2014
Future cash inflows	$ 25,573,856	$23,132,987
Future production costs	(10,493,071)	(9,732,541)
Future development costs	(880,486)	(781,442)
Future income taxes	(2,490,706)	—
Future net cash flows	11,709,593	12,619,004
10% annual discount	(5,554,945)	(5,476,544)
Standardized measure of discounted future net cash flows	$ 6,154,648	$ 7,142,460

The present value (at a 10% annual discount) of future net cash flows from the Company's proved reserves is not necessarily the same as the current market value of its estimated oil and gas reserves. The Company bases the estimated discounted future net cash flows from its proved reserves on average prices realized in the preceding year and on costs in effect at the end of the year. However, actual future net cash flows from the Company's oil and gas properties will also be affected by factors such as actual prices the Company receives for oil and gas, the amount and timing of actual production, supply of and demand for oil and gas and changes in governmental regulations or taxation.

The timing of both the Company's production and incurrence of expenses in connection with the development and production of oil and gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% annual discount factor the Company uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Company or the oil and gas industry in general.

A summary of changes in the standardized measure of discounted future net cash flows is as follows for the years ended December 31, 2013 and 2014:

	2013	2014
Standardized measure of discounted future net cash flows, beginning of year	$ 7,033,189	$ 6,154,647
Sales of oil and gas, net of production costs and taxes	(1,359,448)	(1,190,850)
Purchases of reserves in place	—	—
Sales of reserves in place	(160,748)	—
Changes in development costs	(7,872)	98,054
Revisions of previous estimates	(524,565)	213,112
Changes in prices and production costs	492,325	(341,335)
Net changes in income taxes	(21,553)	440,034
Accretion of discount	703,319	615,465
Standardized measure of discounted future net cash flows, end of year	$ 6,154,647	$ 5,989,127

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

Not Applicable.

Item 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2014, our Chief Executive Officer and Chief Financial Officer (the “Certifying Officers”) conducted evaluations of our disclosure controls and procedures. As defined under Sections 13a-15(e) and 15d-15(e) of the Exchange Act, the term “disclosure controls and procedures” means controls and other procedures of an issuer that are designed to ensure that information required to be disclosed by the issuer in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by an issuer in the reports that it files or submits under the Exchange Act is accumulated and communicated to the issuer’s management, including the Certifying Officers, to allow timely decisions regarding required disclosure. Based on this evaluation, the Certifying Officers have concluded that our disclosure controls and procedures were not effective to ensure that material information is recorded, processed, summarized and reported by our management on a timely basis in order to comply with the disclosure requirements under the Exchange Act and the rules and regulations promulgated thereunder.

Management’s Report on Internal Control Over Financial Reporting.

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Securities Exchange Act, as amended. Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, our management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”) in Internal Control-Integrated Framework. 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 the company’s annual or interim financial statements will not be prevented or detected on a timely basis. We have identified the following material weaknesses.

- Our Board of Directors does not currently have any independent members that qualify as an audit committee financial expert,
- We have not developed and effectively communicated our accounting policies and procedures, and
- Our controls over financial statement disclosures were determined to be ineffective.

Changes in Internal Control Over Financial Reporting.

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

There have been no changes in our internal control over financial reporting during the latest fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. OTHER INFORMATION

Not Applicable.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The directors named below were elected for one-year terms. Officers hold their positions at the discretion of the Board of Directors absent any employment agreements, none of which currently exist or are contemplated. The names, addresses and ages of each of our directors and executive officers and the positions and offices held by them, which director positions are for a period of one year, are:

Name and Address	Age	First Became Officer and/or Director	Position(s)
Donald W. Prosser 7260 Osceola Street Westminster, CO 80030	64	September 2003	Chairman and Chief Financial Officer
Nicholas Scheidt 7260 Osceola Street Westminster, CO 80030	54	November 2012	Director and Chief Executive Officer
Charles B. Davis 7260 Osceola Street Westminster, CO 80030	57	October 2007	Director and Chief Operating Officer
Charles L. Gamber 7260 Osceola Street Westminster, CO 80030	65	September 2003	Director and Secretary
William W. Stewart 7260 Osceola Street Westminster, CO 80030	54	December 2001	Director and Assistant Secretary

Donald W. Prosser

Mr. Prosser is a Director and member of our Compensation and Audit Committees. Mr. Prosser is a practicing certified public accountant, specializing in tax and securities accounting, and has represented a number of companies serving in the capacity of CPA, member of boards of directors, and as Chief Financial Officer. Mr. Prosser brings to the Company an experienced depth of expertise in tax and securities compliance and accounting, corporate finance transactions and turn-around.

From 1997 to 1999, Mr. Prosser served as CFO and Director for Chartwell International, Inc, a publicly traded company which filed reports under the Exchange Act which published high school athletic information and provided athletic recruiting services. From 1999 to 2000, he served as CFO and Director for Anything Internet, Inc. and from 2000 to 2001, served as CFO and Director for its successor, Inform Worldwide Holdings, Inc., which is a publicly traded company which filed reports under the Exchange Act. From 2001 to 2002, Mr. Prosser served as CFO and Director for Net Commerce, Inc, a public company selling internet services. From November 2002 through June 2008, Mr. Prosser served as CFO of VCG Holding Corp., a publicly traded company which filed reports under the Exchange Act and engaged in the business of acquiring, owning and operating nightclubs. His accounting firm performs accounting service for VCG Holding Corp. From July 2008 through August 2009 Mr. Prosser was chief financial officer of IPtimize, Inc., a provider of broadband and data services that filed a petition under federal bankruptcy laws in October 2009. Since July 2013 he has served as a director and then acting chief financial officer (April 2014 to March 2014) of MusclePhar Corporation, a publicly traded company that has a class of securities registered under the Exchange Act.

Mr. Prosser has been a certified public accountant since 1975, and is licensed in the state of Colorado. Mr. Prosser attended the University of Colorado from 1970 to 1971 and Western State College of Colorado from 1972 to 1975, where he earned a Bachelor's degree in both accounting and history (1973) and a Masters degree in accounting – income taxation (1975).

Charles B. Davis

Mr. Davis joined Arête's Board of Directors in 2006, and serves as a member of the Company's Nominating and Compensation Committees. From January 1981 to June 1983, Mr. Davis was Operations Manager for Keba Oil and Gas Co. where he was responsible for drilling, completion and producing operations. From July 1983 to April 1986, Mr. Davis was Vice-President of operations for Private Oil Industries. From April 1986 until August 1988, Mr. Davis did consulting work related to well site operations. Since August 1988 Mr. Davis has worked for DNR Oil & Gas Inc., as president, overseeing the day to day operations for 150 to 200 wells, and involved in exploration activities. Mr. Davis graduated from the University of Wyoming with a Bachelor of Science Degree in Engineering.

Charles L. Gamber

Mr. Gamber joined Arête's Board of Directors in September 2003. He serves as an independent director, and is a member of our Nominating, Audit, and Compensation Committees. Mr. Gamber is the owner of Charles L. Gamber, Inc. dba Capital Resource Management LLC and works as a consultant creating business opportunities and relationships with strategic partners and business organizations. He is also the Director of Business Development for MedCenterNetwork. He has over 35 years of sales, customer service and marketing experience. Mr. Gamber started Charles L Gamber, Inc., in 2003. Mr. Gamber received a bachelor's degree in Business Administration with minors in Accounting and Economics from Western State College of Colorado in 1973.

William W. Stewart

From December, 2001 until August, 2002, Mr. Stewart ran the operations and directed the business plan of Eagle Capital Funding Corp. (Eagle Capital) to pursue capital funding projects. In addition to serving as an outside director, he serves as a member of the Company's Nominating and Compensation Committees. Mr. Stewart worked in the brokerage industry as an NASD licensed registered representative from 1986 to 1994. Mr. Stewart started his career with Boettcher and Company of Denver, Colorado and left the Principal Financial Group of Denver, Colorado in 1994 to open his own small-cap investment firm, S.W. Gordon Capital, Inc., where he has been its president since 1994 to the present. Mr. Stewart formerly served as CEO and is an owner of Larimer County Sports, LLC, a Colorado limited liability company, which owns the Colorado Eagles Hockey Club a minor league professional hockey franchise in northern Colorado. He has been President of Wenatche Sports Partners, LLC, owner of a minor league hockey team, since 2008. Mr. Stewart attended the University of Denver on a full athletic scholarship where he played hockey from 1979 to 1983 as right wing and served as assistant captain during his senior year. Mr. Stewart graduated with a BS, Business Administration from the University of Denver in 1983, with honors as a Student Athlete.

Nicholas L. Scheidt

Mr. Scheidt joined the Company's Board of Directors in November of 2012, and became the Chief Executive Officer in May 2013, and as a member of the Company's Audit, Nomination and Compensation Committees. Mr. Scheidt has served as President and Chairman of Apex Financial Services Corp (aka Apex Realty Investments Inc.) since 1983; he has served on the Board of Directors of Truck Wash Inc. since 1989; he has served on the Board of Directors of Out Reach Housing Corporation since 1992 and he has served as Chief Financial Officer of Truck Wash Inc. since 1995.

Board Committees

Our Board of Directors oversees the business affairs of the Company and monitors the performance of our management. The Board of Directors met five times during the year 2014.

Director Independence

Our common stock is listed on the OTC Markets under the QB tier, which does not have director independence requirements.

Audit, Compensation and Nominating Committees

As noted above, our common stock is listed on the OTC Markets, which does not require companies to maintain audit, compensation or nominating committees consisting solely of independent directors. Nonetheless, we maintain an audit, compensation and nominating committee, although the membership on these committees does not solely consist of independent directors.

Audit Committee

The Audit Committee's primary responsibilities are to monitor our financial reporting process and internal control system, to monitor the audit processes of our independent auditors, and internal financial management; and to provide an open avenue of communication among our independent auditors, financial and senior management and the Board. The Audit Committee reviews its charter annually and updates it as appropriate. The Committee met four times during the year 2014.

Audit Committee Financial Expert

The Board has determined that Mr. Prosser is an audit committee financial expert; however, he is not independent within the meaning of Regulation S-K.

Nominating Committee

The Nominating Committee was also established in 2003. It identifies candidates for future Board membership and proposes criteria for Board candidates and candidates to fill Board vacancies, as well as a slate of directors for election by the shareholders at each annual meeting. The Committee reviews and makes recommendations to the Board concerning the composition, size and structure of the Board and its committees; and annually reviews and reports to the Board on director compensation and benefits matters. The Nominating Committee met one time during the year 2014.

Compensation Committee.

While the Company established a Compensation Committee in 2003, our full Board currently administers compensation matters. As we expand our operations and compensation policies, we intend to appoint members to the committee. Upon reinstatement of the Committee, it will administer our incentive plans, sets policies that govern executives' annual compensation and long-term incentives, and reviews management performance, compensation, development and succession. The Compensation Committee met one time during the year 2014.

Compliance with Section 16(a) of the Exchange Act.

The Company voluntarily files reports under Section l5 (d) of the Exchange Act; accordingly, directors, executive officers and 10% shareholders are not required to make filings under Section 16 of the Exchange Act.

Shareholder Communications.

We do not have a formal shareholder communications process. Shareholders are welcome to communicate with the Company by forwarding correspondence to Arête Industries, Inc., Board of Directors, 7260 Osceola Street, Westminster, Colorado 80030, Attention: Donald W. Prosser, CFO and Director.

CODE OF BUSINESS CONDUCT AND ETHICS

Our corporate philosophy is that good ethics and good business conduct go hand in hand. Our business standards provide a general framework of values and obligations that should be adhered to at all times. Corporate standards guide our professional conduct in regard to actions, words, sense of fairness, honesty and integrity. The Company is required to comply with laws in all jurisdictions, and our Code of Business Conduct and Ethics, which we refer to as the Code, supports and reflects our statutory compliance with such laws. The Code applies to our principal executive officer, principal financial officer, principal accounting officer or controller, and persons performing similar functions.

ITEM 11. EXECUTIVE COMPENSATION

EXECUTIVE COMPENSATION

We do not currently have any full time or part time employees, except as set forth below. Our three executive officers, who are also directors, did not receive any salary or other compensatory benefits during 2013 or 2014 in their capacity as officers. During 2013 and 2014, we used independent contractors, consultants, attorneys and accountants as necessary, to complement services for operations and regulatory filings.

We paid cash of $70,000 and accrued $20,000 for Nicholas Scheidt as his compensation as Chief Executive Officer for 2013 and 2014. We paid no compensation to Donald W. Prosser, P.C. CPA, for 2013 and 2014. Mr. Prosser is our Chief Financial Officer and Director. We also paid Charles Davis $150,000 in 2013 and 2014 for providing us with management services relating to our oil and gas properties. See also "Certain Relationships and Related Transactions" for further information regarding certain transactions with our officers. We paid William W. Stewart $6,000 in cash and accrued $1,800 to be paid in 10,000 shares in common stock in 2014 for management services.

Equity Awards

We do not maintain any equity award plans. Accordingly, there were no stock grants, options or other equity awards to our two executive officers in their capacity as officers.

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Compensation of Directors.

The following table discloses the cash, equity awards and other compensation earned, paid or awarded, as the case may be, to each of our non-employee Directors during the fiscal year ended December 31, 2014.

Name	Fees Earned Or Paid in Cash ($)	Stock Awards ($) (1)	Option Awards ($)	All Other Compensation ($)	Total ($)
Charles Davis	—	4,180	—	—	4,180
Charles Gamber	—	4,180	—	—	4,180
Donald W. Prosser	—	4,180	—	—	4,180
William Stewart	—	4,180	—	—	4,180
Nicholas Scheidt	—	4,180	—	—	4,180

(1) Our Directors are entitled to common shares of the Company’s common stock for each meeting attended. The fee was payable at the end of each calendar quarter and was calculated based on the closing price of our common stock as reported by the OTC Market as of the last day of each quarter. Each of the Company’s five directors attended four meetings resulting in an obligation for the Company to issue an aggregate of 106,142 common shares with an estimated fair value of $20,900 and includes 2,140 common shares from the year ended December 31, 2013.

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Cash Compensation Paid to Directors

We currently do not pay any cash fees to our Directors for services provided in their capacity as Directors.

Equity Based Compensation Paid to Directors

Since we currently do not have any formal equity incentive plans, the stock issued to directors is allocated from our authorized shares. The offer and sale of shares issued in connection with the Directors' fees are not registered with the SEC and are therefore "restricted securities" as that term is defined in Rule 144 of the SEC, and as such are subject to holding period requirements and other restrictions set forth in Rule 144.

Other

All Directors are reimbursed for their reasonable expenses incurred in connection with attending meetings.

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

Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information regarding the beneficial ownership of the Company's common stock as of April 14, 2015 by (i) each person known by the Company to beneficially own more than five percent of the outstanding shares of common stock, (ii) each current director and named executive officer of the Company and (iii) all executive officers and directors as a group. Except as indicated, the persons named in the table have sole voting and investment power with respect to all shares beneficially owned. Outstanding shares at April 14, 2015 were 12,558,459

Title of Class	Name and Address of Beneficial Owner Directors and Executive Officers	Amount and Nature of Beneficial Ownership		Percent of Class
Common Stock	Charles Davis, Director/COO 7260 Osceola Street Westminster, Colorado 80030,	Direct	2,076,534	16.53%
Common Stock	Charles L. Gamber, Director/Secretary 7260 Osceola Street Westminster, Colorado 80030,	Direct	20,159	0.16%
Common Stock	Nicholas L. Scheidt, Director 7260 Osceola Street Westminster, Colorado 80030,	Direct	1,637,775	13.04%
Common Stock	Donald W. Prosser, CFO 7260 Osceola Street Westminster, Colorado 80030,	Direct	1,298,796	10.34%
Common Stock	William W. Stewart, Director 7260 Osceola Street Westminster, Colorado 80030,	Direct	266,554	2.12%
Common Stock	Directors and Officers as a Group (5 persons)	Total:	5,299,818	42.19%

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Item 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Our officers and directors have advanced funds to pay for necessary expenses and costs of the Company. The following are the advances from the officers and directors as of December 31, 2013 and 2014 are unsecured and due on demand:

	2013	2014
Note Payable – Donald W. Prosser , CEO & Director 7% Interest	$ 24,984	$ 23,991
Note Payable – Fairfield Management Group (Donald W. Prosser) 7.50% Interest	150,000	150,000
Note Payable – William W. Stewart 7% Interest	35,000	-0-
Note Payable – Apex Financial Services (Nicholas L Scheidt) 7.5% Interest	714,488	120,728
Note Payable – Charles B. Davis 7% Interest	66,500	55,979
Note Payable – DNR Oil & Gas Inc. (Charles Davis) Variable interest	792,151	792,151
Balances	$1,781,623	$1,142,849

We had related party payables of accrued interest to the officers and directors above of $1,404 at December 31, 2014.

In May 2011 we entered into a purchase and sale agreement, amended in July, 2011, for the purchase of certain oil and gas operating properties in Colorado, Kansas, Wyoming, and Montana with the Tucker Family Investments, LLLP, DNR and Tindall Operating Company, collectively, the "Sellers," for the purchase of certain oil and gas operating properties in Colorado, Kansas, Wyoming, and Montana. In addition, the agreement included an operating agreement for the continued operations of the purchased properties by DNR. DNR is principally owned by Charles B. Davis, our Chief Operating Officer and one of our directors. The consideration for the purchase was determined by bargaining between management of the Company and Mr. Davis, and the Company used reports of independent engineering firms to analyze the purchase price. The base purchase price for the acquisition was $11,000,000. Potential additional purchase price payments are due under the following circumstances:

- The Colorado and Kansas properties provide for additional consideration that is payable to Sellers if proved producing reserves are increased on these properties through drilling or recompletion activities over a period of ten years after the closing date. To the extent that oil reserves increase, the Sellers are entitled to additional consideration of $250,000 for each increase of 20,000 net barrels. Furthermore, to the extent that oil and gas prices increase, the Sellers are entitled to additional consideration as the targeted price thresholds are exceeded for periods of 61 days. The maximum increase in purchase price for the Kansas and Colorado properties is limited to a maximum of $5 million.
- The properties located in Wyoming and Montana provide a similar formula as used for Colorado and Kansas that could result in an obligation for additional purchase consideration to the extent that we perform future drilling or recompletion activities in formations that are not producing as of the closing date. Further, if we sell properties where reserves have been proved up through drilling or recompletion, the Sellers have retained an interest of 70% in the net sales proceeds (after we receive a recovery of 125% of the original purchase price allocation attributed to the properties.

Notwithstanding the foregoing, the maximum increase in purchase price is limited to a maximum of $25 million. Due to sales of some of the properties to unrelated third parties and additional purchase price payable due because the $90 and $100 oil price thresholds were exceeded for 61 consecutive days, the maximum future consideration was reduced to approximately $19.2 million as December 31, 2014.

We also entered into a contract operator agreement with DNR to operate all of the properties purchased pursuant to the purchase and sale agreement, as amended. Under the agreement, DNR:

- operates, manages, and maintains the properties in accordance with past practices;
- employs such personnel as may be reasonably necessary to operate the properties;
- provides various accounting and governmental reporting functions;
- purchases supplies, materials, tools and equipment associated with ownership and operation of the properties;

- pays and performs all obligations of Arête which relate to the properties, including, without limitation, the payment of operating costs, vendor invoices and contractor invoices associated with ownership or operation of the properties; and
- provides marketing, gas control and other similar services necessary to sell the oil and gas produced from the properties.

Under the contract operator agreement, we reimburse DNR for all third party costs and expenses, including without limitation, operating costs, capital expenditures, production taxes and producing, drilling and construction overhead charges billed by third party operators, incurred or borne by DNR and associated with the properties. In addition to the foregoing reimbursements, we pay DNR $23,000 per month for the performance of its services under the contract operator agreement. The operator agreement expired on March 31, 2012 and renews on a month to month basis. Effective July 1, 2012, the monthly operator fee was reduced to $18,000 per month.

On September 29, 2011, as part of our convertible preferred stock private placement of $5.225 million, Mr. Davis purchased 100 shares of our convertible preferred stock for $1 million. On September 29, 2011, as part of our convertible preferred stock private placement of $5.225 million, Mr. Scheidt purchased 100 shares of our convertible preferred stock for $1 million. Effective June 28, 2013, a number of holders of Arête Industries, Inc.'s (the "Company") 15% Series A1 Convertible Preferred Stock ("Series A1 Preferred Stock") elected to convert shares of such stock into the Company's common stock at a deemed conversion price of $0.75 per common share. In connection with those conversions, the Company agreed to reduce the deemed conversion price from $3.35 per common share to $0.75 per common share and all such holders agreed to waive all dividend rights on their shares of Series A1 Preferred Stock subsequent to March 30, 2013. Mr. Davis and Mr. Scheidt elected to convert their preferred stock under these terms. Mr. Davis and Mr. Scheidt received 1,333,333 shares each this agreement.

On September 29, 2012, the Company borrowed $425,000 from an affiliate of a stockholder and director under a note agreement that provides for interest at the stated annual rate of 12% (and an effective annual rate of 17.8%) with unpaid principal and interest due on December 31, 2013. The outstanding principal balance as of December 31, 2012 was $261,109 principal and $5,064 interest due and was paid in full April 29, 2013.

On April 29, 2013, the Company executed a promissory note under which the Company agreed to pay Apex Financial Services Corp, a Colorado corporation, ("Apex") the principal sum of $1,000,000, with interest accruing at an annual rate of 7.5%, with principal and interest due on May 31, 2014 extended to March 31, 2016. The Company also agreed to assign 75% of its operating income from its oil and gas operations and any lease or well sale or any other assets sales to Apex to secure the debt. Apex is 100% owned by the CEO, director, and shareholder of the Company, Nicholas L. Scheidt. The Company borrowed the full amount of principal on the note, and also paid a loan fee of $10,000. In the event of default on the note and failure to cure the default in ten days, Apex may accelerate payment and the annual interest rate on the note will accrue at 18%. Default includes failure to pay the note when due or if the Company borrows any other monies or offers security in the Company or in the collateral securing the note prior to the note being paid in full. The outstanding principal balance as of December 31, 2014 was $120,728 and interest due in the amount of $-0-.

On January 1, 2014, we memorialized our short-term liabilities into formal promissory notes. These certain outstanding advances and other notes payable are now included in single promissory notes, all have been reported previously in our financial statements. Information concerning these promissory notes is set forth in the table below.

Name of Holder	Position	Principal Amount	Interest Rate	Monthly P&I Payment Amount	Number of Monthly Payments
Donald W. Prosser	CFO & Director	$28,500	7.00%	$ 564.33	60
Charles B. Davis	COO & Director	$66,500	7.00%	$1,316.78	60
William Stewart Sold to an unrelated party	Director	$49,500	7.00%	$ 980.16	36

The above-referenced promissory notes contain customary default and acceleration provisions and provide for a default interest rate of 18% per annum.

In addition, we also issued an unsecured promissory note in the amount of $792,151 on January 1, 2014 to DNR Oil & Gas, Inc. (“DNR”). DNR is a company controlled by one of our directors, Charles B. Davis. The DNR note accrues interest at the rate of 2.50% for the calendar years 2014 and 2015, 4.00% for the calendar year 2016, 6.00% for the calendar year 2017 and 8.00% for the remainder of the term of the DNR note. The DNR note matures on January 1, 2019. The DNR note requires payments as follows:

- One payment of $250,000 in 2016;
- One payment of $250,000 in 2017;
- One payment of $250,000 in 2018; and
- The balance of principal and accrued interest on or before January 1, 2019.

The DNR note contains customary default and acceleration provisions and provides for a default interest rate of 18% per annum.

On January 28, 2014, we entered into a line of credit loan agreement for $1,500,000 due January 15, 2015 extended to April 28, 2015, at an unrelated bank. The terms of the note are as follows: 1) the accrued interest is payable monthly starting February 28, 2014, 2) the interest rate is variable based on an index calculated based on a prime rate as published by the Wall Street Journal index (currently 3.25%) plus an add on index with the current and minimum rate of 6.5%., the note has draw provisions, with the first draw of $479,701.39, 4) the note is secured by seven wells and leases owned by the Company, a certificate of deposit for $500,000 at CityWide Bank pledged by a third party, and 5) the personal guarantee of the Nicholas Scheidt, Chief Executive Officer.

The Company signed a contract with an Partnership owned by William W Stewart an Officer and Director to purchase an option to repurchase certain mineral interest currently held by a third party pursuant to a Purchase and Sales Agreement dated July 10, 2014 with that third party, in exchange for issuing 150,000 of its restricted common shares, on or before October 15, 2014 currently valued at $34,500. The Purchase and Sales Agreement states that the option price is $60,000 if it is exercised after December 1, 2014 and before December 31, 2014 and the agreement was extended to September 30, 2015. The Company shall have the right, at its option, to put back the purchase from the partnership owned by the related party on or before February 1, 2016, the minerals, which are the subject matter of the Purchase and Sales Agreement described above, in the amount of $97,500 less any disbursement, royalties, or other revenues derived from the minerals during the period between December 1, 2014 and the Put date in the event that disbursement, royalties, and other revenues during the above described period are less than twelve percent (12%) annual return.

Due to the need of additional assistance with respect to corporate matters and operational needs, in October, 2014, we entered into a Consulting Agreement with William W. Stewart, a Director of the Company, to assist and advise us with respect to the following matters:

(a) Assist the Company with resolving outstanding business issues; advise and assist with respect to proposed transactions and the Company’s business plan.

(b) Assist with operations, including reviewing and advising on correspondence and documents received by the Company.

(c) Review the Company’s insurance needs, obtain quotes and consult with the Company’s officers and Board remembers regarding the same.

(d) Review the Company’s website and advise regarding updating and revising the website.

(e) Review the Company’s organizational documents and related corporate governance documents and advise the Board regarding corporate governance matters and recommend revisions and updates to the organizational documents.

The agreement is for a term of eight months. For his consulting services, we have agreed to pay Mr. Stewart a monthly cash retainer of $3,000 per month. In addition, the Company agreed to issue Mr. Stewart 40,000 restricted shares (the “Restricted Shares”) of the Company’s common stock which are subject to vesting in increments of 5,000 per month. Mr. Stewart will also be entitled to reimbursement of reasonable business expenses incurred by him in connection with his services provided pursuant to the consulting agreement.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The following relate to aggregate fees billed for the last two fiscal years by the Company’s principal accountants concerning the Company’s: (1) audit; (2) for assurance and services reasonably related to the audit; (3) for tax compliance, advice, and planning; and (4) for other fees provided by the principal accountant for the following:

1. Audit Fees. $38,000 (2013) and $48,600 (2014)

2. Audit-Related Fees. $2,468 (2013) and $-0- (2014)

3. Tax Fees. $-0- (2013 and 2014)

4. All Other Fees. $-0- (2013 and 2014)

5. (i) The Company’s Audit Committee’s pre-approval policies and procedures (described in paragraph (c)(7)(i) of Rule 2-01 of Regulation S-X), are:

Audit Committee Pre-Approval Policies and Procedures

As set forth in its charter, our Audit Committee has the sole authority to pre-approve all audit and non-audit services provided by our independent auditor. All services performed by Causey Demgen and Moore, P.C. in 2013 and 2014 were pre-approved by our Audit Committee. Having considered whether the provision of the auditors’ services other than for the annual audit and quarterly reviews is compatible with its independence, the Audit Committee has concluded that it is.

The Audit Committee on an annual basis reviews audit and non-audit services performed by the independent auditors. All audit and non-audit services are pre-approved by the Audit Committee, which considers, among other things, the possible effect of the performance of such services on the auditors’ independence. All requests for services to be provided by the independent auditor, which must include a description of the services to be rendered and the amount of corresponding fees, are submitted to the Chief Executive or Financial Officer. The Chief Executive or Financial Officer authorizes services that have been pre-approved by the Audit Committee. If there is any question as to whether a proposed service fits within a pre-approved service, the Audit Committee chair is consulted for a determination. The Chief Executive or Financial Officer submits requests or applications to provide services that have not been pre-approved by the Audit Committee, which must include an affirmation by the Chief Executive or Financial Officer and the independent auditor that the request or application is consistent with the SEC’s rules on auditor independence, to the Audit Committee (or its chair or any of its other members pursuant to delegated authority) for approval.

(ii) 100 per cent of the fees billed by the principal accountant were approved by the Audit Committee (described in paragraph (c)(7)(i)(C) of Rule 2-01 of Regulation S-X).

6. The percentage (if over 50%) of hours expended on the principal accountant’s engagement to audit the Company’s financial statements for the most recent fiscal year done by persons other than the principal accountant’s full-time, permanent employees, was: Not applicable

PART IV

Item 15. EXHIBITS

The following exhibits are filed with, or incorporated by reference in, this registration statement:

Exhibit Number	Description
3.1	Restated Articles of Incorporation with Amendment adopted by shareholders on September 1, 1998 (filed as Exhibit 3.1 to Form 10-KSB for the year ended December 31, 1998 (filed with the SEC on April 16, 1999), and incorporated herein by reference).
3.2	Articles of Amendment to the Articles of Incorporation of Arête Industries, Inc. – Preferences, Limitations and Relative Rights of 15% Series A1 convertible preferred stock (filed as Exhibit 3.1 to Form 8-K dated September 30, 2011, and incorporated herein by reference.)
3.2(a)	Articles of Amendment to Articles of Incorporation dated May 29, 2012 – Preferences, Limitations and Relative Rights of 15% Series A1 Convertible Preferred Stock (filed as Exhibit 3.2(a) to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference.)
3.3	Bylaws (filed as Exhibit 3.3 to Form 10-K for the year ended December 31, 2010 and filed with the SEC on March 30, 2011.)
10.1	Purchase and Sale Agreement among Tucker Family Investment LLLP, DNR Oil & Gas, Inc., Tindall Operating Company and Arête Industries, Inc., dated May 25, 2011 (filed as Exhibit 10.4 to Form 8-K dated May 25, 2011, and incorporated herein by reference.)
10.2	Security Agreement among Tucker Family Investment LLLP, DNR Oil & Gas, Inc., Tindall Operating Company and Arête Industries, Inc., dated May 25, 2011 (filed as part of Exhibit 10.4 to Form 8-K dated May 25, 2011, and incorporated herein by reference.)
10.3	Purchase agreement with PRB for purchase of pipeline (filed as Exhibit 10.1 to Form 8-K dated September 18, 2006, and incorporated herein by reference.)
10.4	Amended and Restated Purchase and Sale Agreement among Tucker Family Investment LLLP, DNR Oil & Gas, Inc., Tindall Operating Company and Arête Industries, Inc., dated July 29, 2011 (filed as Exhibit 10.5 to Amendment No. 1 to Form 8-K dated May 25, 2011 (filed with the SEC on August 5, 2011), and incorporated herein by reference.)
10.5	First Amendment to the Amended and Restated Purchase and Sale Agreement among Tucker Family Investment LLLP, DNR Oil & Gas, Inc., Tindall Operating Company and Arête Industries, Inc., dated August 12, 2011 (filed as Exhibit 10.8 to Amendment No. 1 to Form 8-K/A dated August 12, 2011 (filed with the SEC on August 18, 2011), and incorporated herein by reference.)
10.6	Second Amendment to the Amended and Restated Purchase and Sale Agreement among Tucker Family Investment LLLP, DNR Oil & Gas, Inc., Tindall Operating Company and Arête Industries, Inc., dated September 16, 2011 (filed as Exhibit 10.9 to Form 8-K dated September 16, 2011, and incorporated herein by reference.)
10.7	Promissory Note due to Pikerni, LLC ($250,000) (filed as Exhibit 10.7 to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference)
10.8	Promissory Note due to Fairfield Management Group, LLC ($150,000) (filed as Exhibit 10.8 to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference)
10.9	Amended and Restated Contract Operator Agreement between DNR Oil & Gas, Inc. and Arête Industries, Inc. (filed as Exhibit 10.9 to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference)
10.10	Agreement regarding Increase in Payments in respect of Amended and Restated Purchase and Sale Agreement (Exhibit C) (filed as Exhibit 10.10 to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference)
10.11	Promissory Note due to Apex Financial Services Corp. ($455,000) and Assignment of Proceeds (filed as Exhibit 10.11 to Amended Registration Statement on Form S-1 filed on October 26, 2012, and incorporated herein by reference)
10.12	Promissory Note due to Apex Financial Services Corp. dated April 2, 2013 (filed as Exhibit 10.12 to Form 8-K dated May 3, 2013, and incorporated herein by reference.)
10.13	Notice of Conversion by Burlingame Equity Investors II, LP, dated June 28, 2013 (filed as Exhibit 10.13 to Form 8-K dated July 5, 2013, and incorporated herein by reference.)
10.14	Notice of Conversion by Burlingame Equity Investors Master Fund, LP, dated June 28, 2013 (filed as Exhibit 10.14 to Form 8-K dated July 5, 2013, and incorporated herein by reference.)

10.15	Promissory Note - Burlingame Equity Investors II, LP, dated June 28, 2013 (filed as Exhibit 10.15 to Form 8-K dated July 5, 2013, and incorporated herein by reference.)
10.16	Promissory Note - Burlingame Equity Investors Master Fund, LP, dated June 28, 2013 (filed as Exhibit 10.16 to Form 8-K dated July 5, 2013, and incorporated herein by reference.)
10.17	Form of Notice of Conversion for holders of Series A1 Preferred Stock other than Burlingame Equity Investors II, LP and Burlingame Equity Investors Master Fund, LP (filed as Exhibit 10.17 to Form 8-K dated July 5, 2013, and incorporated herein by reference.)
10.18	Promissory Note, Dated January 28, 2014 City Wide Bank (filed as Exhibit 10.18 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.19	Promissory Note, Dated January 28, 2014 Donald W Prosser (filed as Exhibit 10.19 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.20	Promissory Note, Dated January 28, 2014 Charles B Davis (filed as Exhibit 10.20 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.21	Promissory Note, Dated January 28, 2014 William Stewart (filed as Exhibit 10.21 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.22	Promissory Note, Dated January 28, 2014 DNR Oil & Gas, Inc. (filed as Exhibit 10.22 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.23	Extension of Burlingame Equity Investors II, LP Promissory Note, Dated January 28, 2014 (filed as Exhibit 10.23 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.24	Extension of Burlingame Equity Investors Master Fund, LP Promissory Note, Dated January 28, 2014 (filed as Exhibit 10.24 to Form 8-K dated February 3, 2014, and incorporated herein by reference.)
10.25	Direct stock purchase agreement between Arête Industries, Inc. and Burlingame Equity Investors Master Fund LP dated January 30, 2014 (filed as Exhibit 10.25 to Form 8-K dated February 21, 2014, and incorporated herein by reference.)
14	Code of Business Conduct and Ethics (filed as Exhibit 14 to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference)
21	List of Subsidiaries (filed as Exhibit 21 to Registration Statement on Form S-1 filed on May 29, 2012, and incorporated herein by reference)
23.1	Consent of Ryder Scott Company*
31.1	Certification of the Principal Executive Officer pursuant to §302 of the Sarbanes-Oxley Act of 2002. *
31.2	Certification of the Principal Financial Officer pursuant to §302 of the Sarbanes-Oxley Act of 2002. *
32.1	Certification of the Principal Executive Officer pursuant to 18 U.S.C. Section 1350. *
32.2	Certification of the Principal Financial Officer pursuant to 18 U.S.C. Section 1350. *
99.1	Reserve Estimate Report of Ryder Scott Company *
101	The following materials are filed herewith: (i) XBRL Instance, (ii) XBRL Taxonomy Extension Schema, (iii) XBRL Taxonomy Extension Calculation, (iv) XBRL Taxonomy Extension Definition, (v) XBRL Taxonomy Extension Labels, and (vi) XBRL Taxonomy Extension Presentation.

* Filed herewith.

SIGNATURES

In accordance with Section 13 or 15(d) of the Exchange Act, the registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Arête Industries, Inc.

April 15, 2015

By: /s/ Nicholas L. Scheidt
Nicholas L. Scheidt,
Chief Executive Officer and Director

In accordance with the Exchange Act, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ Charles L. Gamber Charles L. Gamber	Secretary and Director	April 15, 2015
/s/ Donald W. Prosser Donald W. Prosser	Chairman of the Board and Chief Financial Officer	April 15, 2015
/s/ Nicholas L. Scheidt Nicholas L. Scheidt	Director and Chief Executive Officer	April 15, 2015
/s/ William W. Stewart William W. Stewart	Director	April 15, 2015

Exhibit 23.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Arête Industries, Inc. for the year ended December 31, 2013. We hereby further consent to the use of information contained in our reports setting forth the estimates of revenues from Arête Industries, Inc.'s oil and gas reserves as of December 31, 2013, and to the inclusion of our report dated April 4, 2014 as an exhibit to the Annual Report on Form 10-K of Arête Industries, Inc. for the year ended December 31, 2013.

\s\ Ryder Scott Company L.P.
RYDER SCOTT COMPANY, L.P

Denver, Colorado
April 15, 2015

Exhibit 31.1

CERTIFICATION OF CHIEF EXECUTIVE OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Nicholas L. Scheidt, certify that:

1. I have reviewed this annual report on Form 10-K of Arête Industries, Inc.

2. Based on my knowledge, this annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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)) for the small business issuer 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 any consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

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

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

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

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

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

Dated: April 15, 2015

By: /s/ Nicholas L. Scheidt
Nicholas L. Scheidt, Chief Executive Officer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL ACCOUNTING OFFICER
PURSUANT TO SECTION 302 OF THE SARBANES-OXLEY ACT OF 2002

I, Donald W. Prosser, certify that:

1. I have reviewed this annual report on Form 10-K of Arête Industries, Inc.

2. Based on my knowledge, this annual 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 annual report;

3. Based on my knowledge, the financial statements, and other financial information included in this annual 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 annual 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)) 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 any consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

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

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

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

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

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

Dated: April 15, 2015

By: /s/ Donald W. Prosser
Donald W. Prosser, Chief Financial Officer

EXHIBIT 32.1

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

In connection with the Annual Report of Arête Industries, Inc. (the "Company") on Form 10-K for the fiscal year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Nicholas L. Scheidt, Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Dated: April 15, 2015

By: /s/ Nicholas L. Scheidt
Nicholas L. Scheidt, Chief Executive Officer

EXHIBIT 32.2

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

In connection with the Annual Report of Arête Industries, Inc. (the “Company”) on Form 10-K for the fiscal year ended December 31, 2014, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Donald W. Prosser, Interim Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

Dated: April 15, 2015

By: /s/ Donald W. Prosser
Donald W. Prosser, Chief Financial Officer

Exhibit 99.1

RYDER SCOTT COMPANY
PETROLEUM CONSULTANTS

TBPE REGISTERED ENGINEERING FIRM F-1580 FAX (303) 623-4258
621 SEVENTEENTH STREET SUITE 1550 DENVER, COLORADO 80293 TELEPHONE (303) 623-9147

March 31, 2015

Arête Industries, Inc.
P.O. Box 141
Westminster, CO 80036-0141

Gentlemen:

At your request, Ryder Scott Company, L.P. (Ryder Scott) has prepared an estimate of the proved and probable reserves, future production, and income attributable to certain leasehold interests of Arête Industries, Inc. (Arête) as of December 31, 2014. The subject properties are located in the states of Colorado, Kansas, Montana and Wyoming. The reserves and income data were estimated based on the definitions and disclosure guidelines of the United States Securities and Exchange Commission (SEC) contained in Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). Our third party study, completed on March 31, 2015 and presented herein, was prepared for public disclosure by Arête in filings made with the SEC in accordance with the disclosure requirements set forth in the SEC regulations.

The properties evaluated by Ryder Scott represent 100 percent of the total net proved and probable liquid hydrocarbon reserves and 100 percent of the total net proved and probable gas reserves of Arête as of December 31, 2014.

The estimated reserves and future net income amounts presented in this report, as of December 31, 2014, are related to hydrocarbon prices. The hydrocarbon prices used in the preparation of this report are based on the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements, as required by the SEC regulations. Actual future prices may vary significantly from the prices required by SEC regulations; therefore, volumes of reserves actually recovered and the amounts of income actually received may differ significantly from the estimated quantities presented in this report. The results of this study are summarized below.

SEC PARAMETERS
Estimated Net Reserves and Income Data
Certain Leasehold Interests of
Arête Industries, Inc.
As of December 31, 2014

	Proved		
	Developed Producing	Undeveloped	Total Proved
Net Remaining Reserves			
Oil/Condensate – Barrels	173,375	57,155	230,530
Gas – MCF	614,943	0	614,943
Income Data			
Future Gross Revenue	$17,123,043	$4,822,873	$21,945,916
Deductions	7,394,447	1,932,466	9,326,913
Future Net Income (FNI)	$ 9,728,596	$2,890,407	$12,619,003
Discounted FNI @ 10%	$ 5,358,676	$1,783,784	$ 7,142,460

	Total Probable Undeveloped
Net Remaining Reserves	
Oil/Condensate – Barrels	6,699
Gas – MCF	0
Income Data	
Future Gross Revenue	$ 576,750
Deductions	273,714
Future Net Income (FNI)	$ 303,036
Discounted FNI @ 10%	$ 193,312

Liquid hydrocarbons are expressed in standard 42 gallon barrels. All gas volumes are reported on an “as sold” basis expressed in thousands of cubic feet (MCF) at the official temperature and pressure bases of the areas in which the gas reserves are located. In this report, the revenues, deductions, and income data are expressed as U.S. dollars.

The estimates of the reserves, future production, and income attributable to properties in this report were prepared using the economic software package PHDWin Petroleum Economic Evaluation Software, a copyrighted program of TRC Consultants, L.C. Ryder Scott has found this program to be generally acceptable, but notes that certain summaries and calculations may vary due to rounding and may not exactly match the sum of the properties being summarized. Furthermore, one line economic summaries may vary slightly from the more detailed cash flow projections of the same properties, also due to rounding. The rounding differences are not material.

The future gross revenue is after the deduction of production taxes. The deductions incorporate the normal direct costs of operating the wells, ad valorem taxes and development costs. The future net income is before the deduction of state and federal income taxes and general administrative overhead, and has not been adjusted for outstanding loans that may exist nor does it include any adjustment for cash on hand or undistributed income.

Liquid hydrocarbon reserves account for approximately 84 percent of the total future gross revenue from proved reserves and gas reserves account for the remaining 16 percent of total future gross revenue from the proved reserves reported herein. Liquid hydrocarbon reserves account for approximately 100 percent of the total future gross revenue from probable reserves and gas reserves account for 0 percent of the total future gross revenue from the probable reserves reported herein. There are no possible reserves included in this evaluation.

The discounted future net income shown above was calculated using a discount rate of 10 percent per annum compounded monthly. Future net income was discounted at four other discount rates which were also compounded monthly. These results are shown in summary form as follows.

	Discounted Future Net Income As of December 31, 2014	
Discount Rate Percent	Total Proved	Total Probable
5	$ 9,117,465	$ 240,505
12	$ 6,571,628	$ 177,621
15	$ 5,865,787	$ 156,793
20	$ 4,968,881	$ 127,924

The results shown above are presented for your information and should not be construed as our estimate of fair market value.

Reserves Included in This Report

The proved and probable reserves included herein conform to the definition as set forth in the Securities and Exchange Commission's Regulations Part 210.4-10(a). An abridged version of the SEC reserves definitions from 210.4-10(a) entitled "Petroleum Reserves Definitions" is included as an attachment to this report.

The various proved and probable reserve status categories are defined under the attachment entitled "Petroleum Reserves Status Definitions and Guidelines" in this report.

No attempt was made to quantify or otherwise account for any accumulated gas production imbalances that may exist. The proved and probable gas volumes presented herein do not include volumes of gas consumed in operations as 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." All reserve estimates involve an assessment of the uncertainty relating the likelihood that the actual remaining quantities recovered will be greater or less than the estimated quantities determined as of the date the estimate is made. The uncertainty depends chiefly on the amount of reliable geologic and engineering data available at the time of the estimate and the interpretation of these data. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved. Unproved reserves are less certain to be recovered than proved reserves, and may be further sub-classified as probable and possible reserves to denote progressively increasing uncertainty in their recoverability. At Arête's request, this report addresses the proved and probable reserves attributable to the properties evaluated herein.

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”. The SEC has defined reasonable certainty for proved reserves, when based on deterministic methods, as a “high degree of confidence that the quantities will be recovered.” 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.” Possible reserves are “those additional reserves which are less certain to be recovered than probable reserves” and thus the probability of achieving or exceeding the proved plus probable plus possible reserves is low.

The reserves included herein were estimated using deterministic methods and presented as incremental quantities. Under the deterministic incremental approach, discrete quantities of reserves are estimated and assigned separately as proved, probable or possible based on their individual level of uncertainty. Because of the differences in uncertainty, caution should be exercised when aggregating quantities of oil and gas from different reserves categories. Furthermore, the reserves and income quantities attributable to the different reserve categories that are included herein have not been adjusted to reflect these varying degrees of risk associated with them and thus are not comparable.

Reserve estimates will generally be revised only as additional geologic or engineering data become available or as economic conditions change. For proved reserves, the SEC states that “as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to the estimated ultimate recovery (EUR) with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.” Moreover, estimates of proved and probable reserves may be revised as a result of future operations, effects of regulation by governmental agencies or geopolitical or economic risks. Therefore, the proved and probable reserves included in this report are estimates only and should not be construed as being exact quantities, and if recovered, the revenues therefrom, and the actual costs related thereto, could be more or less than the estimated amounts.

Arête’s operations may be subject to various levels of governmental controls and regulations. These controls and regulations may include, but may not be limited to, matters relating to land tenure and leasing, the legal rights to produce hydrocarbons, drilling and production practices, environmental protection, marketing and pricing policies, royalties, various taxes and levies including income tax and are subject to change from time to time. Such changes in governmental regulations and policies may cause volumes of proved and probable reserves actually recovered and amounts of proved and probable income actually received to differ significantly from the estimated quantities.

The estimates of reserves presented herein were based upon a detailed study of the properties in which Arête owns an interest; however, we have not made any field examination of the properties. No consideration was given in this report to potential environmental liabilities that may exist nor were any costs included for potential liabilities to restore and clean up damages, if any, caused by past operating practices.

Estimates of Reserves

The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the Securities and Exchange Commission’s Regulations Part 210.4-10(a). The process of estimating the quantities of recoverable oil and gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (1) performance-based methods, (2) volumetric-based methods and (3) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserve evaluators must select the method or combination of methods which in their professional judgment is most appropriate given the nature and amount of reliable geoscience and engineering data available at the time of the estimate, the established or anticipated performance characteristics of the reservoir being evaluated, and the stage of development or producing maturity of the property.

In many cases, the analysis of the available geoscience and engineering data and the subsequent interpretation of this data may indicate a range of possible outcomes in an estimate, irrespective of the method selected by the evaluator. When a range in the quantity of reserves is identified, the evaluator must determine the uncertainty associated with the incremental quantities of the reserves. If the reserve quantities are estimated using the deterministic incremental approach, the uncertainty for each discrete incremental quantity of the reserves is addressed by the reserve category assigned by the evaluator. Therefore, it is the categorization of reserve quantities as proved, probable and/or possible that addresses the inherent uncertainty in the estimated quantities reported. For proved reserves, uncertainty is defined by the SEC as reasonable certainty wherein the “quantities actually recovered are much more likely than not to be achieved.” The SEC states that “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.” The SEC states that “possible reserves are those additional reserves that are less certain to be recovered than probable reserves and the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves.” All quantities of reserves within the same reserve category must meet the SEC definitions as noted above.

Estimates of reserves quantities and their associated reserve categories may be revised in the future as additional geoscience or engineering data become available. Furthermore, estimates of reserves quantities and their associated reserve categories may also be revised due to other factors such as changes in economic conditions, results of future operations, effects of regulation by governmental agencies or geopolitical or economic risks as previously noted herein.

The proved and probable reserves for the properties included herein were estimated by performance methods or by analogy. Approximately 100 percent of the proved producing reserves attributable to producing wells and/or reservoirs were estimated by the performance methods. These performance methods include decline curve analysis which utilized extrapolations of historical production and pressure data available through December, 2014. The data utilized in this analysis considered sufficient for the purpose thereof.

Approximately 100 percent of the proved and 100 percent of the probable undeveloped reserves included herein were estimated by the analogy method. The analogy method utilized pertinent well data supplied to Ryder Scott by Arête or which we have obtained from public data sources that were available through December 2014. The data utilized in this analysis considered sufficient for the purpose thereof.

To estimate economically recoverable proved and probable oil and gas reserves and related future net cash flows, we consider many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and SEC pricing requirements, and forecasts of future production rates. Under the SEC regulations 210.4-10(a)(22)(v) and (26), proved and probable reserves must be anticipated to be economically producible from a given date forward based on existing economic conditions including the prices and costs at which economic producibility from a reservoir is to be determined. While it may reasonably be anticipated that the future prices received for the sale of production and the operating costs and other costs relating to such production may increase or decrease from those under existing economic conditions, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Arête has informed us that they have furnished us all of the material accounts, records, geological and engineering data, and reports and other data required for this investigation. In preparing our forecast of future proved and probable production and income, we have relied upon data furnished by Arête with respect to property interests owned, production and well tests from examined wells, normal direct costs of operating the wells or leases, other costs such as transportation and/or processing fees, ad valorem and production taxes, recompletion and development costs, development plans, product prices based on the SEC regulations and adjustments or differentials to product prices. Ryder Scott reviewed such factual data for its reasonableness; however, we have not conducted an independent verification of the data furnished by Arête. We consider the factual data used in this report appropriate and sufficient for the purpose of preparing the estimates of reserves and future net revenues herein.

In summary, we consider the assumptions, data, methods and analytical procedures used in this report appropriate for the purpose hereof, and we have used all such methods and procedures that we consider necessary and appropriate to prepare the estimates of reserves herein. The proved and probable reserves included herein were determined in conformance with the United States Securities and Exchange Commission (SEC) Modernization of Oil and Gas Reporting; Final Rule, including all references to Regulation S-X and Regulation S-K, referred to herein collectively as the “SEC Regulations.” In our opinion, the proved and probable reserves presented in this report comply with the definitions, guidelines and disclosure requirements as required by the SEC regulations.

Future Production Rates

For wells currently on production, our forecasts of future production rates are based on historical performance data. If no production decline trend has been established, future production rates were held constant, or adjusted for the effects of curtailment where appropriate, until a decline in ability to produce was anticipated. An estimated rate of decline was then applied to depletion of the reserves. If a decline trend has been established, this trend was used as the basis for estimating future production rates.

Offset analogies and other related information were used to estimate the anticipated initial production rates for those wells or locations that are not currently producing. For reserves not yet on production, sales were estimated to commence at an anticipated date furnished by Arête. Wells or locations that are not currently producing may start producing earlier or later than anticipated in our estimates due to unforeseen factors causing a change in the timing to initiate production. Such factors may include delays due to weather, the availability of rigs, the sequence of drilling, completing and/or recompleting wells and/or constraints set by regulatory bodies.

The future production rates from wells currently on production or wells or locations that are not currently producing may be more or less than estimated because of changes including, but not limited to, reservoir performance, operating conditions related to surface facilities, compression and artificial lift, pipeline capacity and/or operating conditions, producing market demand and/or allowables or other constraints set by regulatory bodies.

Hydrocarbon Prices

The hydrocarbon prices used herein are based on SEC price parameters using the average prices during the 12-month period prior to the “as of date” of this report, determined as the unweighted arithmetic averages of the prices in effect on the first-day-of-the-month for each month within such period, unless prices were defined by contractual arrangements. For hydrocarbon products sold under contract, the contract prices, including fixed and determinable escalations, exclusive of inflation adjustments, were used until expiration of the contract. Upon contract expiration, the prices were adjusted to the 12-month unweighted arithmetic average as previously described.

Ryder Scott furnished Arête the above mentioned average prices in effect on December 31, 2014. These initial SEC hydrocarbon prices were determined using the 12-month average first-day-of-the-month benchmark prices appropriate to the geographic area where the hydrocarbons are sold. These benchmark prices are prior to the adjustments for differentials as described herein. The table below summarizes the “benchmark prices” and “price reference” used for the geographic areas included in the report.

The product prices that were actually used to determine the future gross revenue for each property reflect adjustments to the benchmark prices for gravity, quality, local conditions, and/or distance from market, referred to herein as “differentials.” The differentials used in the preparation of this report were estimated by Ryder Scott based on information furnished by Arête.

In addition, the table below summarizes the net volume weighted benchmark prices adjusted for differentials and referred to herein as the “average realized prices.” The average realized prices shown in the table below were determined from the total future gross revenue before production taxes and the total net reserves by reserve category for the geographic area and presented in accordance with SEC disclosure requirements for each of the geographic areas included in the report.

Geographic Area	Product	Price Reference	Average Benchmark Prices	Average Proved Realized Prices	Average Probable Realized Prices
United States	Oil/Condensate	WTI Cushing	$94.99/Bbl	$84.09/Bbl	$89.99/Bbl
	Gas	Henry Hub	$4.35/MMBTU	$6.09/MCF	$0.00/MCF

The effects of derivative instruments designated as price hedges of oil and gas quantities are not reflected in our individual property evaluations.

Costs

Operating costs for the leases and wells in this report were furnished by Arête and are based on the operating expense reports of Arête and include only those costs directly applicable to the leases or wells. The operating costs include a portion of general and administrative costs allocated directly to the leases and wells. The operating costs furnished to us were accepted as factual data and reviewed by us for their reasonableness; however, we have not conducted an independent verification of the operating cost data used by Arête. No deduction was made for loan repayments, interest expenses, or exploration and development prepayments that were not charged directly to the leases or wells.

Development costs were furnished to us by Arête and are based on authorizations for expenditure for the proposed work or actual costs for similar projects. Arête's estimates of zero abandonment costs after salvage value were used in this report. Ryder Scott has not performed a detailed study of the abandonment costs or the salvage value and makes no warranty for Arête's estimate.

The proved and probable developed undeveloped reserves in this report have been incorporated herein in accordance with Arête's plans to develop these reserves as of December 31, 2014. The implementation of Arête's development plans as presented to us and incorporated herein is subject to the approval process adopted by Arête's management. As the result of our inquiries during the course of preparing this report, Arête has informed us that the development activities included herein have been subjected to and received the internal approvals required by Arête's management at the appropriate local, regional and/or corporate level. In addition to the internal approvals as noted, certain development activities may still be subject to specific partner AFE processes, Joint Operating Agreement (JOA) requirements or other administrative approvals external to Arête. Additionally, Arête has informed us that they are not aware of any legal, regulatory or political obstacles that would significantly alter their plans. While these plans could change from those under existing economic conditions as of December 31, 2014, such changes were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation.

Current costs used by Arête were held constant throughout the life of the properties.

Standards of Independence and Professional Qualification

Ryder Scott is an independent petroleum engineering consulting firm that has been providing petroleum consulting services throughout the world since 1937. Ryder Scott is employee-owned and maintains offices in Houston, Texas; Denver, Colorado; and Calgary, Alberta, Canada. We have over eighty engineers and geoscientists on our permanent staff. By virtue of the size of our firm and the large number of clients for which we provide services, no single client or job represents a material portion of our annual revenue. We do not serve as officers or directors of any privately-owned or publicly-traded oil and gas company and are separate and independent from the operating and investment decision-making process of our clients. This allows us to bring the highest level of independence and objectivity to each engagement for our services.

Ryder Scott actively participates in industry-related professional societies and organizes an annual public forum focused on the subject of reserves evaluations and SEC regulations. Many of our staff have authored or co-authored technical papers on the subject of reserves related topics. We encourage our staff to maintain and enhance their professional skills by actively participating in ongoing continuing education.

Prior to becoming an officer of the Company, Ryder Scott requires that staff engineers and geoscientists have received professional accreditation in the form of a registered or certified professional engineer's license or a registered or certified professional geoscientist's license, or the equivalent thereof, from an appropriate governmental authority or a recognized self-regulating professional organization.

We are independent petroleum engineers with respect to Arête. Neither we nor any of our employees have any financial interest in the subject properties and neither the employment to do this work nor the compensation is contingent on our estimates of reserves for the properties which were reviewed.

The results of this study, presented herein, are based on technical analysis conducted by teams of geoscientists and engineers from Ryder Scott. The professional qualifications of the undersigned, the technical person primarily responsible for overseeing, reviewing and approving the evaluation of the reserves information discussed in this report, are included as an attachment to this letter.

Terms of Usage

The results of our third party study, presented in report form herein, were prepared in accordance with the disclosure requirements set forth in the SEC regulations and intended for public disclosure as an exhibit in filings made with the SEC by Arête.

Arête makes periodic filings on Form 10-K with the SEC under the 1934 Exchange Act. Our written consent for such use is included as a separate exhibit to the filings made with the SEC by Arête.

We have provided Arête with a digital version of the original signed copy of this report letter. In the event there are any differences between the digital version included in filings made by Arête and the original signed report letter, the original signed report letter shall control and supersede the digital version.

The data and work papers used in the preparation of this report are available for examination by authorized parties in our offices. Please contact us if we can be of further service.

Very truly yours,

RYDER SCOTT COMPANY, L.P.
TBPE Firm Registration No. F-1580

\s\ James L. Baird
[Seal]
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Managing Senior Vice President

\s\ Thomas E. Venglar
[Seal]
Thomas E. Venglar, P.E.
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Senior Petroleum Engineer

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Professional Qualifications of Primary Technical Person

The conclusions presented in this report are the result of technical analysis conducted by teams of geoscientists and engineers from Ryder Scott Company, L.P. James Larry Baird was the primary technical person responsible for overseeing the estimate of the reserves.

Mr. Baird, an employee of Ryder Scott Company, L.P. (Ryder Scott) since 2006, is a Managing Senior Vice President and also serves as Manager of the Denver office, responsible for coordinating and supervising staff and consulting engineers of the company in ongoing reservoir evaluation studies worldwide. Before joining Ryder Scott, Mr. Baird served in a number of engineering positions with Gulf Oil Corporation (1970-1973), Northern Natural Gas (1973-1975) and Questar Exploration & Production (1975-2006). For more information regarding Mr. Baird's geographic and job specific experience, please refer to the Ryder Scott Company website at www.ryderscott.com/Experience/Employees.

Mr. Baird earned a Bachelor of Science degree in Petroleum Engineering from the University of Missouri at Rolla in 1970 and is a registered Professional Engineer in the States of Colorado and Utah. He is also a member of the Society of Petroleum Engineers.

In addition to gaining experience and competency through prior work experience, the Colorado and Utah Board of Professional Engineers recommend continuing education annually, including at least one hour in the area of professional ethics, which Mr. Baird fulfills. As part of his 2011 continuing education hours, Mr. Baird attended an internally presented sixteen hours of formalized training as well as an eight hour public forum. Mr. Baird attended the 2010 and 2011 RSC Reserves Conference and various professional society presentations specifically on the new SEC regulations relating to the definitions and disclosure guidelines contained in the United States Securities and Exchange Commission Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register. Mr. Baird attended an additional sixteen hours of formalized in-house and external training during 2011, 2012 and 2013 covering such topics as the SPE/WPC/AAPG/SPEE Petroleum Resources Management System, reservoir engineering, geoscience and petroleum economics evaluation methods, reserve reconciliation processes, overviews of the various productive basins of North America, evaluations of resource play reserves, procedures and software and ethics for consultants. Mr. Baird was a keynote speaker, presenting the Changing Landscape of the SEC Reporting, at the 2009 Unconventional Gas International Conference held in Fort Worth, Texas.

Based on his educational background, professional training and more than 43 years of practical experience in the estimation and evaluation of petroleum reserves, Mr. Baird has attained the professional qualifications as a Reserves Estimator and Reserves Auditor set forth in Article III of the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007.