IEC ELECTRONICS CORP
Form 10-Q
July 23, 2009

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended June 26, 2009

OR

¨ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the transition period from ____ to ____

Commission File Number 0-6508

IEC ELECTRONICS CORP.

(Exact name of registrant as specified in its charter.)

Delaware	13-3458955
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

105 Norton Street, Newark, New York 14513
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: (315) 331-7742

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 x NO ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data file required to be submitted and posted pursuant to Rule 405 of Regulation S-T (sec. 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

YES ¨ NO ¨

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

Large accelerated filer ¨	Accelerated filer ¨
Non-Accelerated filer x	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 x

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (excludes treasury shares):

Common Stock, $0.01 Par Value - 8,549,113 shares as of July 21, 2009.

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Part 1. Financial Information
Item 1 — Financial Statements

IEC ELECTRONICS CORP. AND ITS SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
JUNE 26, 2009 AND SEPTEMBER 30, 2008
(in thousands)

	JUNE 26, 2009 (Unaudited)	SEPTEMBER 30, 2008
ASSETS		
CURRENT ASSETS:		
Cash (see note #9 page 13)	$ -	$ -
Accounts receivable (net of allowance for doubtful Accounts of $128 and $145 respectively)	9,976	10,345
Inventories	6,592	6,230
Deferred income taxes	1,908	1,908
Other current assets	116	61
Total Current Assets	18,592	18,544
FIXED ASSETS:		
Land and land improvements	742	742
Building and improvements	4,339	4,368
Machinery and equipment	9,846	8,567
Furniture and fixtures	4,105	4,083
Sub-Total Gross Property	19,032	17,760
Less Accumulated Depreciation	(17,088)	(16,907)
Net Fixed Assets	1,944	853
NON-CURRENT ASSETS:		
Deferred income taxes	13,557	14,727
Other Non Current Assets	50	60
Total Non-Current Assets	13,607	14,787
Total Assets	$ 34,143	$ 34,184
LIABILITIES AND SHAREHOLDERS' EQUITY CURRENT LIABILITIES:		
Short term borrowings	$ 1,197	$ 1,098
Accounts payable	4,214	6,125
Accrued payroll and related expenses	970	808
Other accrued expenses	398	603
Customer Deposits (see Note #2)	292	664
Total current liabilities	7,071	9,298
Long term debt	7,864	8,910·

pipeline ruptures; and
·unavailability or high cost of equipment and field services and labor.

A productive well may become uneconomic in the event that unusual quantities of water or other non-commercial substances are encountered in the well bore that impair or prevent production. We may participate in wells that are or become unproductive or, though productive, do not produce in economic quantities. In addition, even commercial wells can produce less, or have higher costs, than we projected.

In addition, initial 24-hour or other limited-duration production rates announced regarding our oil and gas properties are not necessarily indicative of future production rates.

Dry holes and other unsuccessful or uneconomic exploration, exploitation and development activities can adversely affect our cash flow, profitability and financial condition, and can adversely affect our reserves. To the extent we act as a non-operator, we have limited ability to control the manner in which drilling and other exploration and development activities on our properties are conducted, which may increase these risks. Conversely, our anticipated transition to an operated business model entails risks as well. For example, the benefits of this transition may be less, or the costs may be greater, than we currently anticipate. In addition, we may be subject to a greater risk of drilling dry holes or encountering other operational problems until our operating capabilities are more fully developed. Similarly, we may incur liabilities as an operator that we have historically avoided through a non-operated business model.

Our business may be impacted by adverse commodity prices.

In the three years ended December 31, 2014, oil prices have ranged from a high of $110.62 per barrel during September 2013 to a low of $53.45 per barrel during December 2014. Global markets, in reaction to general economic conditions and perceived impacts of future global supply, have caused large fluctuations in price, including an almost 50% decline in the price of oil that occurred over the second half of 2014. Significant future price swings are likely. Natural gas prices have also been volatile, reaching a ten year high during December 2005 on the Henry Hub of $15.39 per MMbtu, and a ten year low during April 2012 of $1.82 per MMbtu. Declines in the prices we receive for our oil and natural gas production can adversely affect many aspects of our business, including our financial condition, revenues, results of operations, cash flows, liquidity, reserves, rate of growth and the carrying value of our oil and natural gas properties, all of which depend primarily or in part upon those prices. For example, due to recent significant decreases in the price of oil, we have reduced our capital expenditure budget for 2015 to $8.2 million from $30.2 million in 2014. The reduction in drilling activity will likely result in lower production and, together with lower realized oil prices, lower revenue and EBITDAX. Declines in the prices we receive for our oil and natural gas can also adversely affect our ability to finance capital expenditures, make acquisitions, raise capital and satisfy our financial obligations. In addition, declines in prices can reduce the amount of oil and natural gas that we can produce economically and the estimated future cash flow from that production and, as a result, adversely affect the quantity and present value of our proved reserves. Among other things, a reduction in the amount or present value of our reserves can limit the capital available to us, as the maximum amount of available borrowing under our Credit Facility is, and the availability of other sources of capital likely will be, based to a significant degree on the estimated quantity and value of the reserves.

Mineral prices also change significantly over time. Molybdenum prices have fluctuated significantly, with a ten-year high of $38.00 per pound in June 2005 to a ten-year low average price of $8.03 per pound in April 2009. The average price at December 31, 2014 was $9.31 per pound, compared to $9.75 per pound at year end 2013. Price improvement in 2015 will be dependent on continued demand, but demand could weaken if industrial consumption sags due to economic constraints in key global markets. Lower molybdenum prices would adversely affect the feasibility of developing the Mt. Emmons Project.

The Williston Basin oil price differential could have adverse impacts on our revenues.

Generally, crude oil produced from the Bakken formation in North Dakota is high quality (36 to 44 degrees API, which is comparable to West Texas Intermediate Crude). However, due to takeaway constraints, our realized oil prices in the Williston Basin generally have been from $13.00 to $21.00 less per barrel than prices for other areas in the United States, and averaged approximately $17.00 less per barrel during the fourth quarter of 2014. This discount, or differential, may widen in the future, which would reduce the price we receive for our production. We may also be adversely affected by widening differentials in other areas of operation.

Drilling and completion costs for the wells we drill in the Williston Basin are comparable to or higher than other areas where there is no price differential. This makes it more likely that a downturn in oil prices will result in a ceiling limitation write-down of our Williston Basin oil and gas properties. A widening of the differential would reduce the cash flow from our Williston Basin properties and adversely impact our ability to participate fully in drilling with Statoil, Zavanna and other operators and to effect our strategy of transitioning to an operated business model. Our production in other areas could also be affected by adverse changes in differentials. In addition, changes in differentials could make it more difficult for us to effectively hedge our exposure to changes in commodity prices.

We may require funding in addition to working capital during 2015.

We were able to maintain adequate working capital in 2014 primarily through borrowing under our Credit Facility and cash flow from operations. Working capital at December 31, 2014 was negative $466,000, an amount insufficient to continue substantial exploration and development work on our oil and gas properties without additional borrowing under our Credit Facility or other funding. In 2015, we have budgeted $8.2 million for work on existing oil and gas programs.

Our exploration and development agreements contain customary industry non-consent provisions. Pursuant to these provisions, if a well is proposed to be drilled or completed but a working interest owner elects not to participate, the resulting revenues (which otherwise would go to the non-participant) flow to the participants until they receive from 150% to 300% of the capital they provided to cover the non-participant's share. In order to be in position to avoid non-consent penalties and to make opportunistic investments in new assets, we will continue to evaluate various options to obtain additional capital, including borrowings under our Credit Facility, sales of one or more producing or non-producing oil and gas assets and/or the issuance of equity.

The oil and gas and minerals businesses present the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. As examples:

- Initial results from one or more of the oil and gas programs could be marginal but warrant investing in more wells. Dry holes, over-budget exploration costs, low commodity prices, or any combination of these or other adverse factors, could result in production revenues below projections, thus adversely impacting cash expected to be available for continued work in a program, and a reduction in cash available for investment in other programs.

- We are paying the annual costs (approximately $1.7 million) to operate and maintain the water treatment plant and stormwater management system at the Mt. Emmons Project, and these costs could increase in the future.

These types of events could require a reassessment of priorities and therefore potential re-allocations of existing capital and could also mandate obtaining new capital. There can be no assurance that we will be able to complete any financing transaction on acceptable terms. For example, our ability to borrow under our Credit Facility may be limited if we are unable, or run a significant risk of becoming unable, to comply with the financial covenants that we are required to satisfy under the agreement. In addition, the borrowing base under the agreement is subject to redetermination periodically and from time to time at the lenders' discretion. Borrowing base reductions may occur as a result of unfavorable changes in commodity prices, asset sales, performance issues or other events. In addition to reducing the capital available to finance our operations, a reduction in the borrowing base could cause us to be required to repay amounts outstanding under the Credit Facility in excess of the reduced borrowing base, and the funds necessary to do so may not be available at that time. Other sources of external debt or equity financing may not be available when needed on acceptable terms or at all, especially during periods in which financial market conditions are unfavorable. Also, the issuance of equity would be dilutive to existing shareholders.

Competition may limit our opportunities in the oil and gas business.

The oil and natural gas business is very competitive. We compete with many public and private exploration and development companies in finding investment opportunities. We also compete with oil and gas operators in acquiring acreage positions. Our principal competitors are small to mid-size companies with in-house petroleum exploration and drilling expertise. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. They also may be willing and able to pay more for oil and natural gas properties than our financial resources permit, and may be able to define, evaluate, bid for and purchase a greater number of properties. In addition, there is substantial competition in the oil and natural gas industry for investment capital, and we may not be able to compete successfully in raising additional capital if needed.

Successful exploitation of the Buda formation, the Williston Basin (Bakken and Three Forks shales) and the Eagle Ford shale is subject to risks related to horizontal drilling and completion techniques.

Operations in the Buda formation and the Bakken, Three Forks and Eagle Ford shales in many cases involve utilizing the latest drilling and completion techniques in an effort to generate the highest possible cumulative recoveries and therefore generate the highest possible returns. Risks that are encountered while drilling include, but are not limited to, landing the well bore in the desired drilling zone, staying in the zone while drilling horizontally through the shale formation, running casing the entire length of the well bore (as applicable to the formation) and being able to run tools and other equipment consistently through the horizontal well bore.

For wells that are hydraulically fractured, completion risks include, but are not limited to, being able to fracture stimulate the planned number of frac stages, and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these latest drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficient period of time.

Currently, the typical cost for drilling and completing a horizontal well is estimated at approximately $3.0 million to $4.0 million for wells targeting the Buda formation, $8.1 million to $10.1 million for wells in the Williston Basin, and $7.5 million for wells in the Eagle Ford, in each case on a gross basis. Costs for any individual well will vary due to a variety of factors. These wells are significantly more expensive than a typical onshore shallow conventional well. Accordingly, unsuccessful exploration or development activity affecting even a small number of wells could have a significant impact on our results of operations. Costs other than drilling and completion costs can also be significant for Williston Basin, Eagle Ford and other wells. For example, we incurred approximately $3.1 million in workover costs relating to a single Williston Basin well in 2011, and these costs substantially exceeded our estimates.

If our access to oil and gas markets is restricted, it could negatively impact our production and revenues. Securing access to takeaway capacity may be particularly difficult in less developed areas of the Williston Basin.

Market conditions or limited availability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and other midstream facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, rail transportation and processing facilities owned and operated by third parties. In particular, access to adequate gathering systems or pipeline or rail takeaway capacity is limited in the Williston Basin. In order to secure takeaway capacity and related services, we or our operating partners may be forced to enter into arrangements that are not as favorable to operators as those in other areas.

As of the date of this report, all of the wells we have drilled in the Williston Basin have produced oil and natural gas (generally at an initial ratio of about 85% oil and 15% gas). Oil sales generally commence immediately after completion work is finished, but natural gas is flared (burned off) until the well can be hooked up to a transmission line. Installation of a gathering system can take from 90 to 120 days, or longer, depending on well location, weather conditions, and availability of service providers. As of the date of this report, all but one of our Williston Basin wells is selling gas.

Continued drilling in the Williston Basin and South Texas has placed additional demands on the capacity of the various gathering and intrastate or interstate transportation pipelines or rail tankers and other midstream facilities available in these areas, and increased production from us and others could exceed available capacity in some areas from time to time. If this occurs, it will be necessary for new rail takeaway lines, pipelines, gathering systems and/or other types of infrastructure to be built. The availability of new or existing infrastructure or services depends on many factors outside of our control. For example, well-publicized accidents involving trains carrying crude oil may lead to new regulations that limit the number of rail cars available to transport our production. In addition, certain pipeline or rail projects that are planned for the Williston Basin and other areas may not occur. In such event, we might have to sell our production for significantly lower prices or shut in our wells until a pipeline connection or rail capacity is available. In the case of natural gas, we may have to flare the gas we produce or shut the well in.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to participate in all or even a substantial portion of the many locations we have potentially available through our agreements with our partners. The extent of our participation will depend on drilling and completion results, commodity prices, the availability and cost of capital relative to ongoing revenues from completed wells, applicable spacing rules and other factors. Significant recent declines in the price of oil may reduce the number of potential locations that we will ultimately drill.

Lower oil and natural gas prices may cause us to record ceiling test write-downs, which would reduce stockholders' equity.

We use the full cost method of accounting to account for our oil and natural gas investments. Accordingly, we capitalize the cost to acquire, explore for and develop these properties. Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" that is based upon the present value of estimated future net revenues from proved reserves, discounted at 10%, plus the lower of the cost or fair market value of unproved properties. If net capitalized costs exceed the ceiling limit, we must charge the amount of the excess to earnings (a charge often referred to as a "ceiling test write-down"). The risk of a ceiling test write-down increases when oil and gas prices are depressed, if we have substantial downward revisions in estimated proved reserves or if we drill unproductive wells.

Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from disposals are credited against accumulated cost, except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated costs, adjusted for contract provisions, any financial derivatives that hedge our oil and gas revenue and asset retirement obligations, and unescalated oil and gas prices during the period, (ii) the cost of properties not being amortized, and (iii) the lower of cost or market value of unproved properties included in the cost being amortized, less (iv) income tax effects related to tax assets directly attributable to the natural gas and crude oil properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs.

Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2014, 2013 and 2012, which were not included in the amortized cost pool, were $12.5 million, $7.5 million and $9.2 million, respectively. These costs consist of wells in progress, costs for seismic analysis of potential drilling locations, and land costs, all related to unproved properties.

We perform a quarterly and annual ceiling test for each of our oil and gas cost centers. At December 31, 2014 and 2013, there was one such cost center (the United States). The ceiling test incorporates assumptions regarding pricing and discount rates over which we have no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2014, we used $94.99 per barrel for oil and $4.35 per MMbtu for natural gas to compute the future cash flows of each of the producing properties at that date. The discount factor used was 10%.

During the first quarter of 2013, capital costs for oil and gas properties exceeded the ceiling test limit and we recorded a ceiling test write-down of $5.8 million primarily due to a decline in the price of oil, additional capitalized well costs and changes in production. We recorded a similar write-down of $5.2 million in 2012. We may be required to recognize additional ceiling test write-downs in future reporting periods depending on the results of oil and gas operations and/or market prices for oil, and to a lesser extent natural gas.

Recent declines in the price of oil have significantly increased the risk of a ceiling test write-down. For example, we expect to use $82.72 per barrel for oil and $3.84 per MMbtu for natural gas to compute the ceiling test limit as of March 31, 2015. Had these prices been used to compute the ceiling test limit as of December 31, 2014 and all other variables (including applicable differentials) remained unchanged, we would have incurred a ceiling test write-down of approximately $14 million. Further, if we assume that the oil price is $50 per barrel for the remainder of 2015, the oil prices used in the ceiling test limit calculation would be approximately $70.06, $57.63 and $50.11 at June 30, 2015, September 30, 2015 and December 31, 2015, respectively. Had these oil prices been used to compute the ceiling test limit as of December 31, 2014, we would have incurred ceiling test write-downs of approximately $31 million, $44 million and $51 million, respectively.

We do not currently operate our drilling locations. Therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of these non-operated assets.

We do not currently operate any of the prospects we hold with industry partners. As a non-operator, our ability to exercise influence over the operations of the drilling programs is limited. In the usual case in the oil and gas industry, new work is proposed by the operator and often is approved by most of the non-operating parties. If the work is approved by the holders of a majority of the working interests, but we disagree with the proposal and do not (or are unable to) participate, we will forfeit our share of revenues from the well until the participants receive 150% to 300% of their investment. In some cases, we could lose all of our interest in the well. We would avoid a penalty of this kind only if a majority of the working interest owners agree with us and the proposal does not proceed.

The success and timing of our drilling and development activities on properties operated by others depend upon a number of factors outside of our control, including:

- the nature and timing of the operator's drilling and other activities;
- the timing and amount of required capital expenditures;
- the operator's geological and engineering expertise and financial resources;
- the approval of other participants in drilling wells; and
- the operator's selection of suitable technology.

The fact that we do not operate our prospects with industry partners makes it more difficult for us to predict future production, cash flows and liquidity needs. Our ability to grow our production and reserves depends on decisions by our partners to drill wells in which we have an interest, and they may elect to reduce or suspend the drilling of those wells.

Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves.

Oil and gas reserve reports are prepared by independent consultants to provide estimates of the quantities of hydrocarbons that can be economically recovered from proved properties, utilizing current commodity prices and taking into account expected capital and other expenditures. These reports also provide estimates of the future net present value of the reserves, which we use for internal planning purposes and for testing the carrying value of the properties on our balance sheet.

The reserve data included in this report represent estimates only. Estimating quantities of, and future cash flows from, proved oil and natural gas reserves is a complex process. It requires interpretations of available technical data and various estimates, including estimates based upon assumptions relating to economic factors, such as future commodity prices, production costs, severance and excise taxes, availability of capital, estimates of required capital expenditures and workover and remedial costs, and the assumed effect of governmental regulation. The assumptions underlying our estimates of our proved reserves could prove to be inaccurate, and any significant inaccuracy could materially affect, among other things, future estimates of the reserves, the economically recoverable quantities of oil and natural gas attributable to the properties, the classifications of reserves based on risk of recovery, and estimates of our future net cash flows.

At December 31, 2014, 43% of our estimated proved reserves were producing, 1% were proved developed non-producing and 56% were proved undeveloped. Estimation of proved undeveloped reserves and proved developed non-producing reserves is almost always based on analogy to existing wells, volumetric analysis or probabilistic methods, in contrast to the performance data used to estimate producing reserves. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. Revenues from estimated proved developed non-producing and proved undeveloped reserves will not be realized until sometime in the future, if at all.

You should not assume that the present values referred to in this report represent the current market value of our estimated oil and natural gas reserves. The timing and success of the production and the expenses related to the development of oil and natural gas properties, each of which is subject to numerous risks and uncertainties, will affect the timing and amount of actual future net cash flows from our proved reserves and their present value. In addition, our PV10 and standardized measure estimates are based on costs as of the date of the estimates and assume fixed commodity prices. Actual future prices and costs may be materially higher or lower than the prices and costs used in the estimate. If prices as of December 31, 2014 were used to derive the estimated quantity and present value of our reserves, those estimates would have been significantly lower than those included in this report, which are based on a 12-month average price under applicable SEC rules.

Further, the use of a 10% discount factor to calculate PV10 and standardized measure values may not necessarily represent the most appropriate discount factor given actual interest rates and risks to which our business or the oil and natural gas industry in general are subject.

The use of hedging arrangements in oil and gas production could result in financial losses or reduce income.

From time to time, we use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil production. The fair value of our derivative instruments will be marked to market at the end of each quarter and the resulting unrealized gains or losses due to changes in the fair value of our derivative instruments will be recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative contracts for the relevant period. If the actual amount of production is higher than we estimated, we will have greater commodity price exposure than we intended. If the actual amount of production is lower than the notional amount that is subject to our derivative instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial diminution of our liquidity. As a result of these factors, our hedging activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counter-party to the derivative instrument defaults on its contract obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- the steps we take to monitor our derivative financial instruments do not detect and prevent transactions that are inconsistent with our risk management strategies.

In addition, depending on the type of derivative arrangements we enter into, the agreements could limit the benefit we would receive from increases in oil prices. It cannot be assumed that the hedging transactions we have entered into, or will enter into, will adequately protect us from fluctuations in commodity prices.

Additionally, the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, among other things, imposes restrictions on the use and trading of certain derivatives, including energy derivatives. The nature and scope of those restrictions will be determined in significant part through regulations that are in the process of being implemented by the SEC, the Commodities Futures Trading Commission and other regulators. If, as a result of the Dodd-Frank Act or its implementing regulations, capital or margin requirements or other limitations relating to our commodity derivative activities are imposed, this could have an adverse effect on our ability to implement our hedging strategy. In particular, a requirement to post cash collateral in connection with our derivative positions, which are currently collateralized on a non-cash basis by our oil and natural gas properties and other assets, would likely make it impracticable to implement our current hedging strategy. In addition, requirements and limitations imposed on our derivative counterparties could increase the costs of pursuing our hedging strategy.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, the loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our potential drilling locations are identified, the leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. The risk that our leases may expire will generally increase when commodity prices fall, as lower prices may cause our operating partners to reduce the number of wells they drill. In addition, on certain portions of our acreage, third-party leases could become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business.

Our producing properties are primarily located in the Williston Basin and South Texas, making us vulnerable to risks associated with having operations concentrated in these geographic areas.

Because our operations are geographically concentrated in the Williston Basin and South Texas (94% of our production in the fourth quarter of 2014 was from these areas), the success and profitability of our operations may be disproportionally exposed to the effect of regional events. These include, among others, regulatory issues, natural disasters and fluctuations in the prices of crude oil and natural gas produced from wells in the region and other regional supply and demand factors, including gathering, pipeline and other transportation capacity constraints, available rigs, equipment, oil field services, supplies, labor and infrastructure capacity. Any of these events has the potential to cause producing wells to be shut-in, delay operations and growth plans, decrease cash flows, increase operating and capital costs and prevent development of lease inventory before expiration. In addition, our operations in the Williston Basin may be adversely affected by seasonal weather and lease stipulations designed to protect wildlife, which can intensify competition for services, infrastructure and equipment during months when drilling is possible and may result in periodic shortages. Any of these risks could have a material adverse effect on our financial condition and results of operations.

Our acquisition activities may not be successful.

As part of our growth strategy, we have made and may continue to make acquisitions. However, suitable acquisition candidates may not continue to be available on terms and conditions we find acceptable, and acquisitions pose substantial risks to our business, financial condition and results of operations. In pursuing acquisitions, we compete with other companies, many of which have greater financial and other resources than we do. The following are some of the risks associated with acquisitions, including any completed or future acquisitions:

- acquired properties may not produce revenues, reserves, earnings or cash flow at anticipated levels, or at all;
- we may assume liabilities that were not disclosed to us or that exceed our estimates;
- we may be unable to integrate acquisitions successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and
- acquisitions could disrupt our ongoing business, distract management, divert resources and make it difficult to maintain our current business standards, controls and procedures.

We may incur losses as a result of title deficiencies in oil and gas leases.

Typically, operators obtain a preliminary title opinion prior to drilling. We rely on our operating partners to provide us with ownership of the interests we pay for. To date, our operators have generally provided preliminary title opinions prior to drilling. However, from time to time, our operators may not retain attorneys to examine title, even on a preliminary basis, before starting drilling operations. If curative title work is recommended to provide marketability of title (and assurance of payment from production), but is not successfully completed, a loss may be incurred from drilling a productive well because the operator (and therefore the Company) would not own the interest.

Insurance may be insufficient to cover future liabilities.

Our business is focused in two areas, each of which presents potential liability exposure: oil and gas exploration and development and permitting and limited exploration of the Mt. Emmons molybdenum property. We also have potential exposure to general liability and property damage associated with the ownership of other corporate assets. In the past, we relied primarily on the operators of our oil and gas properties to obtain and maintain liability insurance for our working interest in our oil and gas properties. In some cases, we may continue to rely on those operators' insurance coverage policies depending on the coverage. However, since June 2011, we have established our own insurance policies for our oil and gas operations that are broader in scope and coverage and are in our control. We also maintain insurance policies for liabilities associated with and damage to general corporate assets.

We also have separate policies for the Mt. Emmons properties and liability and environmental exposures for the water treatment plant operations at the Mt. Emmons project. These policies provide coverage for bodily injury and property damage as well as costs to remediate events adversely impacting the environment. See "Insurance" below.

We would be liable for claims in excess of coverage and for any deductible provided for in the relevant policy. If uncovered liabilities are substantial, payment could adversely impact the Company's cash on hand, resulting in possible curtailment of operations. Moreover, some liabilities are not insurable at a reasonable cost or at all.

Oil and gas and mineral operations are subject to environmental and other regulations that can materially adversely affect the timing and cost of operations.

Oil and gas exploration, development and production activities are subject to certain federal, state and local laws and regulations relating to a variety of issues, including environmental quality and pollution control. These laws and regulations increase costs and may prevent or delay the commencement or continuance of operations. Specifically, the industry generally is subject to regulations regarding the acquisition of permits before drilling, well construction, the spacing of wells, unitization and pooling of properties, habitat and endangered species protection, reclamation and remediation, restrictions on drilling activities in restricted areas, emissions into the environment, management of drilling wastes, water discharges, chemical disclosures and storage and disposition of hazardous wastes. In addition, state laws require wells and facility sites to be abandoned and reclaimed to the satisfaction of state authorities. Such laws and regulations have been frequently changed in the past, and we are unable to predict the ultimate cost of compliance as a result of any future changes. The adoption or enforcement of stricter regulations, if enacted, could have a significant impact on our operating costs.

Our business activities in mining are also regulated by government agencies. Among other things, permits are required to explore for minerals, operate mines and build and operate processing facilities. The regulations under which permits are issued change from time to time to reflect changes in public policy or scientific understanding of issues. If the economics of a project cannot withstand the cost of complying with new or modified regulations, we may decide to not move forward with the project.

In addition, we must comply with numerous environmental laws and regulations with respect to our activities, including the National Environmental Policy Act ("NEPA"), the Clean Air Act, the Clean Water Act, and the Resource Conservation and Recovery Act ("RCRA"). Other laws impose reclamation obligations on abandoned mining properties, in addition to or in conjunction with federal statutes.

Under these laws and regulations, we could be liable for personal injuries, property and natural resource damages, releases or discharges of hazardous materials, well reclamation costs, oil spill clean-up costs, other remediation and clean-up costs, plugging and abandonment costs, governmental sanctions, and other environmental damages. Some environmental laws, such as the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), impose joint and several and strict liability. Strict liability means liability without fault such that in some situations we could be exposed to liability for clean-up costs and other damages as a result of conduct that was lawful at the time it occurred or otherwise without negligence on our part or for the conduct of third parties. These third parties may include prior operators of properties we have acquired, operators of properties in which we have an interest and parties that provide transportation services for us. If exposed to joint and several liabilities, we could be responsible for more than our share of a particular clean-up, reclamation or other obligation, and potentially for the entire obligation, even where other parties were involved in the activity giving rise to the liability.

Federal, state and local legislation and regulations relating to hydraulic fracturing could result in increased costs, additional drilling and operating restrictions or delays in the production of natural gas and crude oil, and could prohibit hydraulic fracturing activities.

Many of our activities involve the use of hydraulic fracturing, which is a process that creates a fracture extending from the well bore in a rock formation to enable oil or natural gas to move more easily through the rock pores to a production well. Fractures typically are created through the injection of water and chemicals into the rock formation.

Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used by the oil and natural gas industry in fracturing fluids under the Safe Drinking Water Act ("SDWA"), and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, the Emergency Planning and Community Right-to-Know Act ("EPCRA"), or other laws. Sponsors of these bills, which have been subject to various proceedings in the legislative process, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. In March 2011, the Environmental Protection Agency ("EPA") announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. EPA issued an initial report about the study in December 2012. The initial report described the focus of the continuing study but did not include any data concerning EPA's efforts to date, nor did it draw any conclusions about the safety of hydraulic fracturing. A draft report including data and conclusions is expected in 2015 and a final, peer-reviewed report is expected in 2016.

EPA also has begun a Toxic Substances Control Act ("TSCA") rulemaking which will collect expansive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. In addition, in January 2015, several national environmental advocacy groups filed a lawsuit requesting that EPA add the oil and gas extraction industry to the list of industries required to report releases of certain "toxic chemicals" under EPCRA's Toxics Release Inventory (TRI) program. Concurrently, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices.

EPA also finalized major new Clean Air Act standards (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants) applicable to hydraulically fractured natural gas wells in August 2012 known as "Quad O." The standards require, among other things, use of reduced emission completions, or green completions, to reduce volatile organic compound emissions during hydraulically fractured natural gas well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers, and dehydrators at gas well affected facilities. Following a legal challenge and several petitions for administrative reconsideration of the Quad O rules, EPA issued final amendments related to storage tanks, green completions, and other provisions of the rule in September 2013 and December 2014, respectively. Most key provisions in Quad O take effect in 2015. The rules associated with such standards are substantial and will likely increase future costs of our operations and will require us to make modifications to our operations or install new equipment.

EPA has also issued permitting guidance under the SDWA for the underground injection of liquids from hydraulically fractured (and other) wells where diesel is used. This guidance may create duplicative requirements, further slow down the permitting process in certain areas, increase the costs of operations, and result in expanded regulation of hydraulic fracturing activities by EPA depending on how it is implemented. Certain other federal agencies are analyzing, or have been requested to review, environmental issues associated with hydraulic fracturing. Most notably, the U.S. Department of the Interior, through the Bureau of Land Management ("BLM"), is currently conducting a rulemaking that will require, among other things, disclosure of chemicals and more stringent well integrity measures associated with hydraulic fracturing operations on public land. BLM has not indicated when it will issue a final rule, but an Advanced Notice of Proposed Rulemaking is expected in Spring 2015. BLM also is expected to continue assessing the need for additional rules and regulations to address venting and flaring associated with oil and natural gas production on BLM land.

Currently, hydraulic fracturing is regulated primarily at the state level through permitting and other compliance requirements. For example, North Dakota, Montana, Texas, and Louisiana require disclosure of information concerning the chemicals used in hydraulic fracturing fluids. In Montana, disclosure of information about hydraulic fracturing fluids is on a well-by-well basis. Further, in Montana and Louisiana, operators must generally obtain approval from the state before hydraulic fracturing occurs and submit a report after the work is performed. Montana, Texas, and North Dakota also require specific construction and testing requirements for wells that will be hydraulically fractured. Certain state governments have adopted or are considering adopting laws and regulations that impose or could impose, among other requirements, stringent permitting or air emission control requirements, disclosure, wastewater disposal, baseline sampling, well construction and well location requirements on hydraulic fracturing operations or otherwise seek to ban underground injection of fracturing wastewater or fracturing activities altogether. At the local level, some municipalities and local governments have adopted or are considering similar actions.

In addition, lawsuits have been filed against unrelated third parties in a number of states alleging contamination of drinking water by hydraulic fracturing. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to natural gas and crude oil production activities using hydraulic fracturing techniques. Additional legislation, litigation, regulation, or moratoria could also lead to operational delays or lead us to incur increased operating costs in the production of crude oil and natural gas, including from the development of our shale plays, or could make it more difficult to perform hydraulic fracturing or other drilling activities. If these legislative, regulatory, litigation, and other initiatives cause a material decrease in the drilling of new wells and in related servicing activities, our profitability could be materially impacted.

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

President Obama has made proposals that would, if enacted into law, make significant changes to United States tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could defer or eliminate certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

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

Climate change has emerged as an important topic in public policy debate. It is a complex issue, with some scientific research suggesting that rising global temperatures are the result of an increase in greenhouse gases ("GHGs"). Products produced by the oil and natural gas exploration and production industry are a source of certain GHGs, namely carbon dioxide and methane, and future restrictions on the combustion of fossil fuels or the venting and release of fugitive emissions of natural gas could have a significant impact on our future operations. EPA has issued a notice of finding and determination that emissions of carbon dioxide, methane and other GHGs present an endangerment to human health and the environment, which has allowed the EPA to begin regulating emissions of GHGs under existing provisions of the Clean Air Act. The EPA has begun to implement GHG-related reporting and permitting rules. In June 2014, however, the United States Supreme Court invalidated a portion of EPA's GHG program in the case Utility Air Regulatory Group v. EPA. Specifically, under the Supreme Court's UARG opinion, sources that are subject to the federal Title V and/or the Prevention of Significant Deterioration ("PSD") programs because of emissions of non-GHG pollutants may still be subject to GHG permitting, including requirements to install Best Available Control Technology ("BACT"). Sources that would be subject to Title V or PSD because of GHG emissions only, however, are no longer subject to GHG permitting requirements, including GHG BACT requirements. Upon remand, EPA currently is considering how to implement the Court's decision.

The U.S. Congress also has considered, and may in the future consider, "cap and trade" legislation that would establish an economy-wide cap on emissions of GHGs in the United States and would require most sources of GHG emissions to obtain GHG emission "allowances" corresponding to their annual emissions of GHGs. Similarly, President Obama has indicated that climate change and GHG regulation is a significant priority for his second term. The President issued a Climate Action Plan in June 2013 that, among other things, calls for a reduction in methane emissions from the oil and gas sector. In Spring 2014, EPA issued five "Methane White Papers" exploring methane emissions from, and possible controls for, various aspects of the oil and natural gas production process. As noted above, building on these white papers, in January 2015, EPA announced a comprehensive strategy to further reduce methane emissions from the U.S. oil and gas industry, which will likely include some additional mandatory requirements, including potentially leak detection and repair obligations, controls for hydraulically fractured oil wells, as well as other control, monitoring, and recordkeeping requirements applicable to a variety of oil and gas facility processes and associated equipment.

In November 2013, the President released an Executive Order charging various federal agencies, including EPA, with devising and pursuing strategies to improve the country's preparedness and resilience to climate change. In part through these executive actions, the direct regulation of methane emissions from the oil and gas sector continues to be a focus of regulation. Any laws or regulations that may be adopted to restrict or reduce emissions of GHGs would likely require us to incur increased operating costs and could have an adverse effect on demand for our production. For example, as part of state-level efforts to reduce these emissions, operating restrictions on emissions by drilling rigs and completion equipment could be enacted, leading to an increase in drilling and completion costs. Also, the emergence of trends such as a worldwide increase in hybrid power motor vehicle sales, and/or decreased personal motor vehicle use by individuals in response to regulatory changes and/or perceived negative impacts on the climate from GHGs could result in lower world-wide consumption of, and prices for, crude oil.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Williston Basin and the Gulf Coast can be adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities sometimes cannot be conducted as effectively during the winter months, and this can materially increase our operating and capital costs. Gulf Coast operations are also subject to the risk of adverse weather events, including hurricanes.

Shortages of equipment, services and qualified personnel could reduce our cash flow and adversely affect results of operations.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil and natural gas prices and activity levels in new regions, causing periodic shortages. These problems can be particularly severe in certain regions such as the Williston Basin and Texas. During periods of high oil and gas prices, the demand for drilling rigs and equipment tends to increase along with increased activity levels, and this may result in shortages of equipment. Higher oil and natural gas prices generally stimulate increased demand for equipment and services and subsequently often result in increased prices for drilling rigs, crews and associated supplies, oilfield equipment and services, and personnel in exploration, production and midstream operations. These types of shortages and subsequent price increases could significantly decrease our profit margin, cash flow and operating results and/or restrict or delay our ability to drill those wells and conduct those activities that we currently have planned and budgeted, causing us to miss our forecasts and projections.

We do not have a feasibility study relating to Mt. Emmons.

We have not yet completed a feasibility study on the Mt. Emmons Project. A feasibility study would establish the potential economic viability of the molybdenum property based on a reassessment of historical and additional drilling and sampling data, the design of and costs to build and operate a mine and mill, the cost of capital, and other factors. A feasibility study conducted by professional consulting and engineering firms will determine if the deposit contains proved reserves (i.e., amounts of minerals in sufficient grades that can be extracted profitably under current commodity pricing assumptions and estimated development and operating costs).

The timing and cost of obtaining a feasibility study for the Mt. Emmons property cannot be predicted. However, when such a study is obtained, it may not support our internal valuations of the property, and additionally may not be sufficient to attract new partners or investment capital.

The exploration and future development of our Mt. Emmons Project is highly speculative, involves substantial expenditures, and may be non-productive.

Mineral exploration and development, including the exploration and development of our Mt. Emmons Project, involves a high degree of risk. Exploration projects are frequently unsuccessful and few prospects that are explored are ultimately developed into producing mines. We cannot assure you that our exploration or development efforts at Mt. Emmons will be successful. Substantial expenditures are required to determine if the project has economically mineable mineralization, and our ability to fund these expenditures will be driven substantially by the market price for molybdenum. It could take several years to obtain the necessary governmental approvals and permits to establish proven and probable mineral reserves and to develop and construct mining and processing facilities. Because of these uncertainties, it cannot be assumed that our efforts at Mt. Emmons will result in the discovery of economic mineral reserves or the development of the project into a producing mine. Similarly, other attempts to create value from the Mt. Emmons Project may not be successful.

Development of the Mt. Emmons Project is subject to numerous environmental and permitting risks.

The Mt. Emmons Project is located on fee property within the boundary of U.S. Forest Service ("USFS") land. Although mining of the mineral resource would occur on fee property, associated ancillary activities will occur on USFS land. The Company submitted a full mine plan of operations to the USFS in part to satisfy the requirements of the conditional water rights decree on October 10, 2012. The USFS has notified us that it will prepare an environmental analysis under the procedures mandated by NEPA in the form of an environmental impact statement to evaluate the predicted environmental and socio-economic impacts of the proposed mine plan. The NEPA process provides for public review and comment on the proposed plan.

The USFS is the lead regulatory agency in the NEPA process, and coordinates with the various federal and state agencies in the review and approval of the mine plan of operations. Various Colorado state agencies will have primary jurisdiction over certain areas. For example, enforcement of the Clean Water Act in Colorado is delegated to the Colorado Department of Public Health and Environment. A water discharge permit under the Colorado Discharge Permit System ("CDPS") is required before the USFS can approve the plan of operations. We currently have CDPS permits for the discharge from the water treatment plant treating water flowing from the historic Keystone Mine workings and for stormwater discharges associated with the Mt. Emmons Project, but this project is not related to the proposed mining activities.

In addition, the Colorado Division of Reclamation, Mining and Safety ("DRMS") issues mining and reclamation permits for mining activities pursuant to the Colorado Mined Land Reclamation Act, and otherwise exercises supervisory authority over mining in the state. As part of obtaining a permit to mine, we will be required to submit a detailed reclamation plan for the eventual mine closure, which must be reviewed and approved by the agency. In addition, we will be required to provide financial assurance that the reclamation plan will be achieved (by bonding and/or insurance) before a mining permit will be issued.

Obtaining and maintaining the various permits for the mining operations at the Mt. Emmons Project will be complex, time-consuming, and expensive, and likely to be subject to ongoing litigation. Changes in a mine's design, production rates, quality of material mined, and many other matters, often require submission of the proposed changes for agency approval prior to implementation. In addition, changes in operating conditions beyond our control, or changes in agency policy and federal and state laws, could further affect the successful permitting of the mine operations and the costs of complying with environmental permits and related requirements. The timing, cost, and ultimate success of our future development efforts and mining operations cannot be predicted.

In July 2009, the EPA announced that it will develop financial assurance requirements under CERCLA § 108(b) for the hardrock mining industry, specifically including molybdenum mining. EPA expects to publish its proposed financial responsibility regulations in 2016. EPA's notice did not indicate what the anticipated scope of these requirements will be, or whether they will be duplicative of existing bonding and other financial assurance requirements applicable to the hardrock mining industry. However, the promulgation of regulations that require significant additional financial assurance could adversely impact the economic viability of the Mt. Emmons project.

We depend on key personnel.

Our employees have experience in dealing with the acquisition of and financing of oil and gas as well as mineral properties, but we have a limited technical staff. From time to time we rely on third party consultants for professional engineering, geophysical and geological advice in oil and gas matters. The loss of key employees could adversely impact our business, as finding replacements could be difficult as a result of competition for experienced personnel in the oil and gas and minerals industry.

Risks Related to Our Stock

We have authorization to issue shares of preferred stock with greater rights than our common stock.

Although we have no current plans, arrangements, understandings or agreements to do so, our articles of incorporation authorize the board of directors to issue one or more series of preferred stock and set the terms of the stock without seeking approval from holders of the common stock. Preferred stock that is issued may have preferential rights over the common stock in terms of dividends, liquidation rights and voting rights.

Future equity transactions and exercises of outstanding options or warrants could result in dilution.

From time to time, we have sold common stock, warrants and convertible debt to investors in private placements and public offerings. These transactions caused dilution to existing shareholders. Also, from time to time, we issue options and warrants to employees, directors and third parties as incentives, with exercise prices equal to the market price at the date of issuance. Exercise of options and warrants would result in dilution to existing shareholders. Future issuances of equity securities, or securities convertible into equity securities, would also have a dilutive effect on existing shareholders. In addition, the perception that such issuances may occur could adversely affect the market price of our common stock.

We do not intend to declare dividends on our common stock.

We paid a one-time special cash dividend of $0.10 per share on our common stock in July 2007. However, we do not intend to declare dividends in the foreseeable future. Accordingly, stockholders must look solely to increases in the price of our common stock to realize a gain on their investment, and this may not occur.

We could implement take-over defense mechanisms that could discourage some advantageous transactions.

Although our shareholder rights plan expired in 2011, certain provisions of our governing documents and applicable law could have anti-takeover effects. For example, we are subject to a number of provisions of the Wyoming Management Stability Act, an anti-takeover statute, and have a classified or "staggered" board. We could implement additional anti-takeover defenses in the future. These existing or future defenses could prevent or discourage a potential transaction in which shareholders would receive a takeover price in excess of then-current market values, even if a majority of the shareholders support such a transaction.

Our stock price likely will continue to be volatile.

Our stock is traded on the Nasdaq Capital Market. In the two years ended December 31, 2014, the stock has traded as high as $5.00 per share and as low as $1.17 per share. The principal factors which have contributed and/or in the future could contribute to this volatility include:

- price volatility in the oil and gas commodities markets;
- price and volume fluctuations in the stock market generally;
- relatively small amounts of stock trading on any given day;
- fluctuations in our financial operating results;
- industry trends;
- legislative and regulatory changes; and
- global economic uncertainty.

The stock market has recently experienced significant price and volume fluctuations, and oil and natural gas prices have declined significantly. These fluctuations have particularly affected the market prices of securities of oil and gas companies like ours. These market fluctuations could adversely affect the market price of our stock.

Item 1 B - Unresolved Staff Comments.

None.

Item 2 – Properties

Oil and Natural Gas

The following table sets forth our net proved reserves as of the dates indicated. We do not have in-house geophysical or reserve engineering expertise. We therefore primarily rely on the operators of our producing wells who provide production data to our reserve engineers.

Our reserve estimates as of December 31, 2014, 2013 and 2012 are based on reserve reports prepared by Cawley, Gillespie & Associates, Inc., or CGA. CGA is a nationally recognized independent petroleum engineering firm and is a Texas Registered Engineering Firm (F-693). Our primary contact at CGA is Mr. W. Todd Brooker, Senior Vice President. Mr. Brooker is a State of Texas Licensed Professional Engineer (License #83462). The reserve estimates were based upon the review (by the relevant contracted engineering firm(s)) of the production histories and other geological, economic, ownership and engineering data, as provided by us and the corresponding operators to them. A copy of CGA's report is filed as an exhibit to this report.

Summary of Oil and Gas Reserves as of Fiscal Year End (1)

	December 31, 2014	2013	2012
Net proved reserves			
Oil (Bbls)			
Developed	1,754,668	1,875,528	1,770,659
Undeveloped	2,365,069	1,584,187	842,984
Total	4,119,737	3,459,715	2,613,643
Natural gas (Mcf)			
Developed	1,892,446	1,701,282	1,420,295
Undeveloped	1,318,801	670,628	377,791
Total	3,211,247	2,371,910	1,798,086
Total proved reserves (BOE)	4,654,944	3,855,033	2,913,324

(1) Reserve estimates are based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period. Reserve estimates as of December 31, 2014 are based on prices of $94.99 per barrel of oil and $4.35 per MMbtu of natural gas, in each case adjusted for regional price differentials and other factors.

As of December 31, 2014, our proved reserves totaled 4,654,944 BOE (44% developed and 56% undeveloped), comprised of 4,119,737 Bbls of oil (89% of the total) and 3,211,247 Mcf of natural gas (11% of the total). See the "Glossary of Oil and Gas Terms" for an explanation of these and other terms. You should not place undue reliance on estimates of proved reserves. See "Risk Factors - Our estimated reserves are based on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or the relevant underlying assumptions will materially affect the quantity and present value of our reserves". A variety of methodologies are used to determine our proved reserve estimates. The principal methodologies employed are reservoir simulation, decline curve analysis, volumetrics, material balance, advance production type curve matching, petrophysics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates in substantially all of our fields.

We maintain an effective system of internal controls over the reserve estimation process as well as the underlying data upon which reserve estimates are based. The primary inputs to the reserve estimation process are comprised of technical information, financial data, ownership interests and production data. All field and reservoir technical information is assessed for validity when meetings are held with management, land personnel and third party operators to discuss field performance and to validate future development plans. Current revenue and expense information is obtained from our accounting records, which are subject to external quarterly reviews, annual audits and their own set of internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated into the reserve database as well and verified to ensure their accuracy and completeness. Our reserve database is maintained by CGA. CGA works with our personnel to review field performance, future development plans, current revenues and expense information. Following these reviews, the reserve database and supporting data is updated so that CGA can prepare its independent reserve estimates and final report.

Proved Undeveloped Reserves

As of December 31, 2014, we had 2,584,869 BOE (91% oil and 9% natural gas) of proved undeveloped reserves, which is an increase of 888,911 BOE, or 52%, compared with 1,695,958 BOE of proved undeveloped reserves at December 31, 2013. This increase was primarily due to increased density in the Bakken formation in North Dakota. Due to lower oil prices, drilling activity in North Dakota has slowed. However, this slowdown has resulted in increased competition among drilling and completion services companies and lower drilling and completion costs. In addition, there has been an overall longer term trend of lower drilling and completion costs; since 2012, drilling and completion costs for horizontal wells on our properties in the Williston Basin have dropped from approximately $11.5 million to a range of approximately $8.1 to $10.1 million. Our development plan contemplates an increase in Bakken drilling after 2015 as a result of reduced costs and commodity prices moving closer to forward strip prices.

We invested approximately $8.3 million to convert 381,187 BOE of proved undeveloped reserves to proved developed reserves in 2014 (representing 22.5% of our beginning of year proved undeveloped reserves). The following table details the changes in the quantity of proved undeveloped reserves during the year ended December 31, 2014:

December 31, 2014	BOE
Beginning of year	1,695,958
Conversion to Proved Developed Producing	(381,187)
Revisions of previous quantity estimates	(122,967)
Extensions, discoveries and improved recoveries	1,588,709
Purchase of reserves in place	--
Sales of reserves in place	(195,644)
End of year	2,584,869

As of December 31, 2014, we have no proved undeveloped reserves that have been on the books in excess of five years and we have recorded no material proved undeveloped locations that were more than one direct offset from an existing producing well. Additionally, no proved undeveloped reserves are scheduled for development beyond five years of initial booking. As of December 31, 2014, estimated future development costs relating to proved undeveloped reserves are projected to be approximately $70.8 million over the next five years.

Oil and Gas Production, Production Prices, and Production Costs

The following table sets forth certain information regarding our net production volumes, average sales prices realized and certain expenses associated with sales of oil and natural gas for the periods indicated. We urge you to read this information in conjunction with the information contained in our financial statements and related notes included in this report. The information set forth below is not necessarily indicative of future results.

	December 31, 2014	2013	2012
Production Volume			
Oil (Bbls)	329,828	343,719	373,531
Natural gas (Mcf)	564,849	408,352	347,810
Natural gas liquids (Bbls)	41,372	13,155	13,203
BOE	465,342	424,933	444,702
Daily Average Production Volume			
Oil (Bbls/d)	904	942	1,021
Natural gas (Mcf/d)	1,548	1,119	950
Natural gas Liquids (Bbls/d)	113	36	36
BOE/d	1,275	1,164	1,215
Oil Price per Bbl Produced			
Realized Price	$85.89	$90.81	$82.38
Natural Gas Price per Mcf Produced			
Realized Price	$4.72	$4.66	$3.25
Natural Gas Liquids Price per Bbl Produced			
Realized Price	$33.48	$40.42	$47.84
Average Sale Price per BOE (1)	$69.58	$79.18	$73.16
Expense per BOE			
Production costs (2)	$16.93	$16.78	$16.42
Depletion, depreciation and amortization	$31.56	$32.06	$33.49

(1) Amounts shown are based on oil and natural gas sales, divided by sales volumes. Natural gas produced but flared is not included.

(2) Production costs are comprised of oil and natural gas production expenses (excluding ad valorem and severance taxes), and are computed using production costs as determined under ASC 932-235-55.

The following table provides a regional summary of our production for the years ended December 31, 2014, 2013 and 2012:

	December 31,		
	2014	2013	2012
Williston Basin (North Dakota)			
Oil (Bbls)	212,052	280,789	352,372
Natural gas (Mcf)	121,605	145,586	124,077
Natural gas liquids (Bbls)	12,796	9,654	12,113
BOE	245,116	314,707	385,165
Eagle Ford / Buda (South Texas)			
Oil (Bbls)	110,413	53,603	10,283
Natural gas (Mcf)	269,634	69,022	27,351
Natural gas liquids (Bbls)	27,916	2,788	437
BOE	183,268	67,895	15,279
Austin Chalk (South Texas)			
Oil (Bbls)	6,627	7,717	7,756
Natural gas (Mcf)	3,019	3,433	1,494
Natural gas liquids (Bbls)	362	589	176
BOE	7,492	8,878	8,181
Gulf Coast (Louisiana and Texas)			
Oil (Bbls)	736	1,610	3,120
Natural gas (Mcf)	170,591	190,311	194,888
Natural gas liquids (Bbls)	298	124	477
BOE	29,466	33,453	36,078
Total			
Oil (Bbls)	329,828	343,719	373,531
Natural gas (Mcf)	564,849	408,352	347,810
Natural gas liquids (Bbls)	41,372	13,155	13,203
BOE	465,342	424,933	444,702

Drilling and Other Exploratory and Development Activities

The following table sets forth information with respect to development and exploration wells we completed from January 1, 2012 through December 31, 2014. The number of gross wells is the total number of wells we participated in, regardless of our ownership interest in the wells.

	For the years ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive	14.00	1.55	15.00	1.33	11.00	1.76
Non-productive	--	--	--	--	--	--
	14.00	1.55	15.00	1.33	11.00	1.76
Exploratory:						
Productive	21.00	2.73	15.00	0.84	8.00	1.12
Non-productive	--	--	1.00	0.20	7.00	1.39
	21.00	2.73	16.00	1.04	15.00	2.51
Total	35.00	4.28	31.00	2.37	26.00	4.27

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of oil and natural gas that may ultimately be recovered. See "Management's Discussion and Analysis of Financial Condition and Results of Operation – General Overview."

Oil and Natural Gas Properties, Wells, Operations and Acreage

The following table details our working interests in producing wells as of December 31, 2014. A well with multiple completions in the same bore hole is considered one well. Wells are classified as oil or natural gas wells according to the predominant production stream, except that a well with multiple completions is considered an oil well if one or more is an oil completion.

	Gross Producing Wells	Net Producing Wells	Average Working Interest [(1)]	
Oil	135.00	19.85	14.70	%
Natural Gas	1.00	0.17	17.00	%
Total [(1)]	136.00	20.02	14.72	%

(1) The average working interest for the ninety-nine Williston Basin wells producing at December 31, 2014 is 10.4%; the remaining thirty-seven wells (in Texas and Louisiana) have an average working interest of 26.3%.

The following map reflects where our oil and gas properties are generally located:

Acreage

The following table summarizes our estimated developed and undeveloped leasehold acreage as of December 31, 2014.

	Developed		Undeveloped		Total	
AREA	Gross	Net	Gross	Net	Gross	Net
Williston Basin						
Rough Rider Prospect	19,200	1,175	--	--	19,200	1,175
Yellowstone and SEHR Prospects	35,840	1,225	--	--	35,840	1,225
ASEN North Dakota Acquisition	16,320	114	--	--	16,320	114
Wolverine Prospect, Daniels County, MT	--	--	13,450	997	13,450	997
East Texas and Louisiana	1,824	289	--	--	1,824	289
Buda/Eagle Ford/Austin Chalk						
Leona River Prospect	4,965	1,490	--	--	4,965	1,490
Booth Tortuga Prospect	12,013	3,050	1,900	375	13,913	3,425
Big Wells Prospect	240	36	4,003	600	4,243	636
Carrizo Creek and South McKnight Prospects	640	213	11,460	3,171	12,100	3,384
TOTAL	91,042	7,592	30,813	5,143	121,855	12,735

As a non-operator, we are subject to lease expiration if the operator does not commence the development of operations within the agreed terms of our leases. All of our leases for undeveloped acreage summarized in the table below will expire at the end of their respective primary terms, unless we renew the existing leases, establish commercial production from the acreage or some other "savings clause" is exercised. In addition, our leases typically provide that the lease does not expire at the end of the primary term if drilling operations have been commenced. While we generally expect to test or establish production from most of our acreage prior to expiration of the applicable lease terms, there is no assurance that we can do so. The approximate expiration of our gross and net acres which are subject to expiration between 2015 and 2018 are set forth below:

	Williston Basin, North Dakota and Montana		Buda / Eagle Ford / Austin Chalk, Texas		East Texas and Louisiana		TOTAL	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
2015	9,890	775	3,207	962	-	-	13,097	1,737
2016	3,320	201	1,600	285	-	-	4,920	486
2017	80	1	761	203	-	-	841	204
2021	160	20	-	-	-	-	160	20
	13,450	997	5,568	1,450	-	-	19,018	2,447

Present Activities

As of March 5, 2015, five gross (0.02 net) wells were drilled and waiting on completion.

Molybdenum – Mt. Emmons Project

The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,345 unpatented mining and mill site claims, which together approximate 9,853 acres, or over 15 square miles of claims and fee lands. The Mt. Emmons Project is located in Gunnison County, Colorado. The property is accessed by vehicle traffic on Gunnison County Road 12.

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We own both surface and mineral rights at the Mt. Emmons Project in fee pursuant to mineral patents issued by the federal government. All fee property requires the payment of property taxes to Gunnison County. Unpatented mining and mill site claims require the payment of an annual maintenance fee to the BLM; the total amount paid for mining and millsite claim maintenance fees in 2014 was $214,000.

The breakdown of the property is as follows:

	Acres	Claims
Patented Claims / Fee Land	365	25
Unpatented Claims	5,923	664
Mill Site Claims	3,405	681
Fee Property	160	n/a
Total	9,853	1,370

Title

Approximately 25 of the Mt. Emmons Project mining claims are patented claims; however, the majority of claims are unpatented.

Unpatented claims are located upon federal and public land pursuant to procedures established by the General Mining Law, which governs mining claims and related activities on federal public lands. Requirements for the location of a valid mining claim on public land depend on the type of claim being staked, but generally include discovery of valuable minerals, erecting a discovery monument and posting thereon a location notice, marking the boundaries of the claim with monuments, and filing a certificate of location with the county in which the claim is located and with the BLM. If the statutes and regulations for the location of a mining claim are complied with, the locator obtains a valid possessory right to the contained minerals. To preserve an otherwise valid claim, a claimant must also pay certain rental fees annually to the federal government and make certain additional filings with the county and the BLM. Failure to pay such fees or make the required filing may render the mining claim void or voidable.

Because mining claims are self-initiated and self-maintained, they possess some unique vulnerability not associated with other types of property interests. It is impossible to ascertain the validity of unpatented mining claims solely from public records and it can be difficult or impossible to confirm that all of the requisite steps have been followed for location and maintenance of a claim. If the validity of an unpatented mining claim is challenged by the government, the claimant has the burden of proving the economic feasibility of mining minerals located thereon. However, we believe that all of our Mt. Emmons Project mining claims are valid and in good standing.

History of the Mt. Emmons Project

We leased various patented and unpatented mining claims on the Mt. Emmons Project to Amax, Inc. ("Amax") in 1974. In the late 1970s, Amax delineated a large deposit of molybdenum on the properties, reportedly containing approximately 155 million tons of mineralized material averaging 0.44% molybdenum disulfide (MoS_2). In 1981, Amax constructed a water treatment plant at the Mt. Emmons Project to treat water flowing from the historic Keystone mine workings and for potential use in milling operations. By 1983, Amax had reportedly spent an estimated $150 million in the acquisition of the property, securing water rights, extensive exploration, ore body delineation, mine planning, metallurgical testing and other activities involving the mineral deposit. Amax was merged into Cyprus Minerals in 1992 to form Cyprus Amax. Phelps Dodge ("PD") then acquired the Mt. Emmons Project in 1999

through its acquisition of Cyprus Amax. Thereafter, PD acquired additional conditional water rights and patents to certain mineral claims. The Company re-acquired the Mt. Emmons Project on February 28, 2006. The property was returned to us by PD in accordance with a 1987 Amended Royalty Deed and Agreement between us and Amax.

The exploration work conducted in the late 1970s by Amax as discussed in Cyprus Amax's Patent Claim Application to the BLM dated December 23, 1992, defined the initial mineralized material at the Mt. Emmons Project as follows: "Molybdenite is present in randomly distributed veinlets (i.e. stockwork veining) and in some larger veins that are up to two feet wide. This mineralized zone is found in metamorphosed sedimentary rocks and in Tertiary igneous complex which acted as the source of the mineralization."

There also are a number of existing mine adits located on the property. Historic work completed by Amax in the 1970s and early 1980s included 2,400 feet of new drift with 18 underground diamond drill stations to facilitate underground drilling (consisting of 168 diamond drill holes for a total of 157,037 feet of core drilling). The majority of the drilling was concentrated within 3,000 feet north and south; 3,000 feet east and west and 2,000 vertical feet defining the area of mineralized material. A bulk sample was collected from this area and sent off site for metallurgical testing.

In its 1992 patent application, Cyprus Amax stated that the size and grade of the Mt. Emmons deposit was determined to approximate 220 million tons of mineralized material grading 0.366% molybdenite. In a letter dated April 2, 2004, the BLM estimated that there was about 23 million tons of mineralized material containing 0.689% molybdenite, and that about 267 million pounds of molybdenum trioxide was recoverable. This letter covered only the high-grade mineralization, which is only a portion of the total mineral deposit delineated to date. The analysis set forth in the letter was based upon a price of $4.61 per pound for molybdic oxide and was used by the BLM in determining that nine claims satisfied the patenting requirement that the mining claims contain a valuable mineral that could be mined profitably.

We note that the statements made by the predecessor owners of the Mt. Emmons Project regarding "recoverable" minerals and "mineralized material" were based on costs, permitting requirements and commodity prices then prevailing. We believe these estimates to be relevant, but they should not be relied upon. Substantial additional exploration and drilling efforts and a full feasibility study will be required, using current estimated capital costs and operating expenses, to estimate the viability of the project. It will be possible to classify some, or none, of the mineralized resources as "reserves" or "recoverable" only after a full feasibility study, based on a specific mine plan, has been completed.

In December 2008, an additional 160 acres of fee land in the vicinity of the claims was purchased by the Company and Thompson Creek Metals Company USA ("Thompson Creek" or "TCM") for $4 million ($2 million in January 2009, $400,000 annually for five years). On January 21, 2014, the Company purchased TCM's interest in the property for $1.2 million.

Geology

The sedimentary sequence in the Mt. Emmons area spans from the late Cretaceous to the early Tertiary periods. The oldest formation is the Mancos, a 4,000 foot sequence of shales with some interbedding limestone and siltstones. The Mancos Formation is not exposed on Mt. Emmons, but may be seen in valley bottoms a few miles to the north, south, and east. All of the Mancos Formation encountered in the vicinity of the Mt. Emmons mineralization has been strongly metamorphosed and attempts to correlate internal divisions of the unit have not been made. The overlying Mesaverde Formation, also of the late Cretaceous age, consists of a massive repetitive sequence of alternating sandstones, siltstones, shales and minor coals. Coal seams were not observed in any of the diamond drill holes, or in any of the underground drifts. On Mt. Emmons the Mesaverde Formation varies from 1,100 to 1,700 feet thick. The variability in thickness of the Mesaverde Formation is mainly due to post-depositional erosion. The Ohio Creek Formation, dominantly a coarse sandstone with local chert pebble conglomerate and well-defined shale to siltstone beds, overlies the Mesaverde Formation. The Ohio Creek Formation is of early Tertiary (Paleocene) age and remains fairly consistent at 400 feet thick on Mt. Emmons. Capping Mt. Emmons is the Wasatch Formation, also of early Tertiary (Paleocene to Eocene) age.

On a more regional scale, within the Ruby Range the Wasatch Formation may reach 1,700 feet in thickness. However, on Mt. Emmons specifically, all but the basal 600 to 700 feet has been eroded. The Wasatch Formation is composed of alternating sequences of immature shales, siltstones, arkosic sandstones, and volcanic pebble conglomerates. The Mt. Emmons stock has intruded the Mancos and Mesaverde sediments, strongly metamorphosing both formations to hornfels up to 1,500 feet outward from the igneous body. Sedimentary rocks on Mt. Emmons generally dip 15 – 20 degrees to the southeast, south, and southwest as is consistent with the locations of the Oh-Be-Joyful anticline and Coal Creek syncline.

During crystallization of the Red Lady Complex, hydrothermal fluids collected near the top of the magma column. These fluids were released after a period of intense fracturing in the solid upper portions of the Red Lady Complex and the surrounding country rock. This release of fluids was responsible for the formation of the major part of the Mt. Emmons molybdenum mineralized zone and the associated alteration zones. Hydrothermal alteration associated with the Mt. Emmons stock occurs in several distinct overlapping zones. Altered rocks include sedimentary rocks of the Mancos, Mesaverde, Ohio Creek and Wasatch Formations, the rhyodacite porphyry sills, and rocks of the Mt. Emmons stock.

Water Treatment Plant; Site Facilities

PD's 2006 re-conveyance of the property to the Company also included the transfer of ownership and operational responsibility of the mine water treatment plant located on the property. The water treatment permit issued under the Colorado Discharge Permit System was assigned to us by the Colorado Department of Public Health and Environment ("CDPHE"). We are responsible for all operating and maintenance costs. Also, as described in the Mine Plan of Operations submitted to the USFS, the Company currently plans to use the mine water treatment plant in the milling operations for the Mt. Emmons Project. We also are investigating reclamation strategies that may be used to reduce the quantity of discharge water and improve the quality of treated water and stormwater subject to permit-related requirements.

The water treatment plant was constructed by Amax in 1981 (at a cost of approximately $15 million) to treat mine discharge water from the historic Keystone Mine which produced lead and zinc. A certified water treatment plant operations contractor with five licensed and/or trained employees operates the water treatment plant on a continuous basis, treating water discharged from the historic Keystone Mine. The plant utilizes a standard lime pH adjustment to precipitate heavy metals from the water. Mine water is then filtered and discharged to Coal Creek in accordance with the requirements of the CDPS permit for the plant, and solids are dewatered and mixed with cement for proper disposal in accordance with state and federal law. The existing permit is under administrative extension awaiting renewal. Modifications and improvements to the treatment system were tested and implemented in 2012 and 2013. We also maintain coverage under the CDPS General Permit for Stormwater Discharges associated with the Metal Mining Industry. This permit provides authorization to discharge stormwater from the Mt. Emmons Project subject to the general requirements of the permit itself, which are applicable to all active and inactive metal mining operations in Colorado, and a site-specific stormwater management plan. Permit modifications in 2012 required ongoing monitoring of stormwater discharges and the reporting of monitoring results to the CDPHE. In 2013, we commenced a more comprehensive study of natural and human-induced conditions in the region that may be affecting water quality in Coal Creek. Those efforts continued in 2014, and will continue through 2015.

Historical Capital Expenditures by Prior Owners, and Related Information

Amax reportedly spent approximately $150 million in exploration and related activities on the Mt. Emmons Project, which included construction of the water treatment plant. Since the Company reacquired the property in 2006, an additional $22.7 million has been spent on the development of the property. In addition, our annual operating cost for the water treatment plant is approximately $1.7 million. The total costs associated with future drilling and the development of the project has not yet been determined.

We are using grid electric power to operate the water treatment plant and other facilities from the local electric utility serving Gunnison County.

Activities in 2012 - 2014 and Plans for 2015

On October 10, 2012, the Company submitted a full mine plan of operations to the USFS to satisfy the requirements of the conditional water rights decree. In 2014, we submitted a Plan of Operations to the USFS related to hydrology data collection from areas of proposed activity in proximity to the proposed project infrastructure sites. This Plan of Operations includes field work such as borings, test pits and ground water monitoring wells. The USFS will have to review the Plan of Operations and follow the NEPA process before approval will be given. Field work is expected to commence following approval by the USFS and providing weather allows access to the field sites.

Proposed Federal Legislation

The U.S. Congress from time to time has considered proposed revisions to the General Mining Law, including as recently as 2009. If these proposed revisions are enacted, payment of royalties on production of minerals from federal lands could be required as well as additional procedural measures, new requirements for reclamation of mined land, and other environmental control measures. The effect of any revision of the General Mining Law on operations cannot be determined until enactment. However, it is possible that revisions would materially increase the carrying and operating costs of mineral properties located on federal unpatented mining claims.

Information About Molybdenum Markets

The metallurgical market for molybdenum is characterized by cyclical and volatile prices, little product differentiation and strong competition. In the market, prices are influenced by production costs of domestic and foreign competitors, worldwide economic conditions, world supply/demand balances, inventory levels, the U.S. Dollar exchange rate and other factors. Molybdenum prices also are affected by the demand for end-use products in, for example, the construction, transportation and durable goods markets. A substantial portion the of world's molybdenum supply is produced as a by-product of copper mining. Today, by-product production is estimated to account for approximately 60% of global molybdenum production.

Annual Metal Week Dealer Oxide mean prices for molybdenum averaged $11.60 in 2014, compared to $10.40 in 2013.

Real Estate

Remington Village - Gillette, Wyoming

Remington Village Sale

We previously owned Remington Village, a nine-building multifamily apartment complex with 216 units on 10.015 acres in Gillette, Wyoming. On September 11, 2013, the Company, through its wholly owned subsidiary Remington Village LLC, completed the sale of Remington Village to an affiliate of the Miller Frishman Group, LLC for $15.0 million. The $9.5 million balance on the commercial note due on Remington Village was paid in full at closing. After deduction of payment of the note, commission and other closing costs, net proceeds to the Company were approximately $5.0 million. The proceeds were allocated to the Company's oil and gas business, reduction of debt and general corporate purposes.

Fremont County, Wyoming

U.S. Energy owns a 14-acre tract in Riverton, Wyoming, with a two-story 30,400 square foot office building. The first floor is rented to non-affiliates and government agencies; the second floor is occupied by the Company.

In addition, we own three city lots covering 13.84 acres adjacent to our corporate office building and one unrelated vacant lot covering approximately 9.41 acres in Fremont County, Wyoming. We intend to sell these properties without development. However, there can be no assurance that sales of any of these properties will be completed on the terms, or in the time frame, we expect or at all.

Corporate Aircraft and Related Facilities Sale

On January 10, 2013, the Company sold its corporate aircraft for $1.9 million and related facilities for $767,000. The proceeds were allocated to our oil and gas business and general corporate purposes.

Sold Uranium Properties – Possible Future Revenues

In 2007, we sold all of our uranium assets for cash and stock of the purchaser, Uranium One Inc. ("Uranium One"). Included in the sold assets were the Shootaring Canyon uranium mill in Utah and unpatented uranium claims in Wyoming, Colorado, Arizona and Utah. Pursuant to the asset purchase agreement, we may also receive from Uranium One:

- $20,000,000 cash when the Shootaring Canyon Mill has been operating at 60% or more of its design capacity of 750 short tons per day for 60 consecutive days.

- $7,500,000 cash on the first delivery (after commercial production has occurred) of mineralized material from any of the claims we sold to a commercial mill (excluding existing ore stockpiles on the properties).

- From and after the time commercial production occurs at the Shootaring Canyon Mill, a production payment royalty (up to but not more than $12,500,000) equal to five percent of (i) the gross value of uranium and vanadium products produced at and sold from the mill; or (ii) mill fees received by the purchaser from third parties for custom milling or tolling arrangements, as applicable. If production is sold to an affiliate of the purchaser, partner, or joint venturer, gross value shall be determined by reference to mining industry publications or data.

On August 14, 2014, conditioned upon the closing of a purchase and sale transaction between Anfield Resources Inc. ("Anfield") and Uranium One, the Company agreed to release Anfield from the future payment and royalty obligations stemming from the Company's 2007 sale of its uranium properties to Uranium One as described above. In return, Anfield has agreed to pay the Company the following:

1. $2.5 million in Anfield common shares upon closing of the transactions contemplated by the asset purchase agreement between Anfield and Uranium One. The shares will be held in escrow and released in tranches over a 36 month period,
2. $2.5 million in cash paid upon 18 months of continuous commercial production, and
3. $2.5 million in cash paid upon 36 months of continuous commercial production.

Should Anfield be unsuccessful in closing the purchase and sale transaction with Uranium One, the original payment and royalty obligations will remain unchanged.

The timing of any potential future receipt of funds from any of these contingencies is not known.

<u>Royalty on Uranium Claims</u>

We hold a 4% net profits interest on certain unpatented mining claims on Rio Tinto's Jackpot uranium property located on Green Mountain in Wyoming.

Research and Development

No research and development expenditures have been incurred, either on the Company's account or sponsored by a customer of the Company, during the past three fiscal years.

Marketing, Major Customers and Delivery Commitments

Markets for oil and natural gas are volatile and are subject to wide fluctuations depending on numerous factors beyond our control, including seasonality, economic conditions, foreign imports, political conditions in other energy producing countries, OPEC market actions, and domestic government regulations and policies. All of our production is marketed by our industry partners for our benefit and is sold to competing buyers, including large oil refining companies and independent marketers. Substantially all of our production is sold pursuant to agreements with pricing based on prevailing commodity prices, subject to adjustment for regional differentials and similar factors. We had no material delivery commitments as of December 31, 2014.

Competition

The oil and natural gas business is highly competitive in the search for and acquisition of additional reserves and in the sale of oil and natural gas. Our competitors principally consist of major and intermediate sized integrated oil and natural gas companies, independent oil and natural gas companies and individual producers and operators. In particular, we compete for property acquisitions and our operating partners compete for the equipment and labor required to operate and develop our properties. Our competitors may be able to pay more for properties and may be able to define, evaluate, bid for and purchase a greater number of properties than we can. Ultimately, our future success will depend on our ability to develop or acquire additional reserves at costs that allow us to remain competitive.

Environmental

Like the oil and natural gas industry in general, our properties are subject to extensive and changing federal, state and local laws and regulations designed to protect and preserve natural resources and the environment. The recent trend in environmental legislation and regulation is generally toward stricter standards, and this trend is likely to continue. These laws and regulations often require a permit or other authorization before construction or drilling commences and for certain other activities; limit or prohibit access, seismic acquisition, construction, drilling and other activities on certain lands; impose substantial liabilities for pollution resulting from our operations; and require the reclamation of certain lands. Federal, state and local laws and regulations regarding the discharge of materials into the environment or otherwise relating to the protection of the environment include NEPA, the Clean Air Act, the Federal Water Pollution Control Act of 1972 (the "Clean Water Act"), the Colorado Water Quality Control Act, the Oil Pollution Act of 1990, RCRA, and CERCLA. Regulations and permit requirements applicable to our operations have been changed frequently in the past and, in general, these changes have imposed more stringent requirements that increase operating costs and/or require capital expenditures to remain in compliance. Failure to comply with these requirements can result in civil and/or criminal penalties and liability for non-compliance, clean-up costs and other environmental damages. It also is possible that unanticipated developments or changes in the law could require us to make environmental expenditures significantly greater than those we currently expect. See "Federal, state and local legislation and regulations relating to hydraulic fracturing could result in increased costs, additional drilling and operating restrictions or delays in the production of natural gas and crude oil, and could prohibit hydraulic fracturing activities" and "Climate change legislation or regulations restricting emissions of 'greenhouse gases' could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce" in "Risk Factors" for a discussion of certain regulatory developments that may have an adverse effect on us.

With respect to proposed mining operations at the Mt. Emmons Project, Colorado's mine permitting statute, the Abandoned Mine Reclamation Act, and industrial development and siting laws and regulations, may also affect the project. We believe we are in compliance in all material respects with existing environmental regulations. In October 2012, the CDPHE modified the CDPS stormwater permit for the site to require additional monitoring to determine whether or not stormwater discharges from the site are in full compliance with permit requirements. The CDPHE may impose more stringent requirements when the permit is renewed (the prior permit expired as of August 31, 2013, and the CDPHE administratively extended the permit, including all existing discharge limitations, pending renewal). In addition, we will continue monitoring activities at and surrounding the Mt. Emmons Project in 2015 in an effort to identify sources of heavy metals loading to Coal Creek. The results of these studies may be used to revise water quality standards and permit limits in a way that better ensures the feasibility of discharge permit compliance long term. We also are investigating reclamation strategies that may be used to reduce the quantity of discharge water and improve the quality of treated water and stormwater subject to permit-related requirements. For information on the approximate reclamation costs (decommissioning, decontamination and other reclamation efforts for which we are primarily responsible or potentially responsible) related to the Mt. Emmons Project, see the consolidated financial statements included in Part II of this Annual Report.

We may generate wastes, including "solid" wastes and "hazardous" wastes that are subject to regulation under RCRA and comparable state statutes, although certain mining and oil and natural gas exploration and production wastes currently are exempt from regulation as hazardous wastes under RCRA. EPA has limited the disposal options for certain wastes that are designated as hazardous wastes. Moreover, certain wastes generated by our mining and oil and natural gas operations that currently are exempt from regulation as hazardous wastes may in the future be designated as hazardous wastes and, as a result, become subject to more rigorous and costly management, disposal and remediation requirements.

Although all of our currently producing oil and gas properties are currently operated by third parties, the activities on the properties are still subject to environmental protection regulations that affect us. Operators are required to obtain drilling permits, restrict substances that can be released into the environment, and require remedial work to mitigate pollution from our operations, close and cover disposal pits, and plug abandoned wells. Violations by the operator could result in substantial liabilities for which we could be responsible. Based on the current regulatory environment in those states in which we have oil and natural gas investments and rules and regulations currently in effect, we do not currently expect to make any material capital expenditures for environmental control facilities.

Oil and gas operations also are subject to various federal, state and local regulations governing oil and natural gas production and state limits on allowable rates of production by well. These regulations may affect the amount of oil and natural gas available for sale, the availability of adequate pipeline and other regulated transportation and processing facilities, and other matters. State and federal regulations generally are intended to prevent waste of oil and natural gas, protect groundwater resources, protect rights to produce oil and natural gas between owners in a common reservoir, control the amount produced by assigning allowable rates of production and control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. From time to time, regulatory agencies and legislative bodies make various proposals to change existing requirements or to add new requirements. Regulatory changes can adversely impact the permitting and exploration and development of mineral and oil and gas properties including the availability of capital.

Wells in the Bakken and Three Forks formations in North Dakota produce natural gas as well as crude oil. Constraints in the current gas gathering network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. The North Dakota Industrial Commission, the State's chief energy regulator, recently issued an order to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. In addition, the Commission is requiring operators to develop gas capture plans that describe how much natural gas is expected to be produced, how it will be delivered to a processor and where it will be processed. Production caps or penalties will be imposed on certain wells that cannot meet the capture goals.

In addition, oil and gas and mineral projects are subject to extensive permitting requirements. Failure to timely obtain required permits to start operations at a project could cause delay and/or the failure of the project resulting in a potential write-off of the investments made.

Insurance

The following summarizes the material aspects of the Company's insurance coverage:

General

We have liability insurance coverage in amounts we deem sufficient for our business operations, consisting of property loss insurance on all major assets equal to the approximate replacement value of the assets and additional liability and control of well insurance for our oil and gas drilling programs. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in curtailment of projected future operations.

Mt. Emmons Project

The Company is responsible for all costs to operate the water treatment plant at the Mt. Emmons Project. We maintain an insurance policy for our benefit in the amounts of $1 million per event, $2 million aggregate general liability, $1 million automobile liability, $10 million environmental impairment liability, and $10 million excess liability (an upper limit on the coverage other than environmental).

We believe the above insurance is sufficient in the current permitting-exploration stage of the Mt. Emmons Project. Additional insurance will be obtained as the level of activity in exploration and development expands.

Employees

As of December 31, 2014, we had 14 full-time employees.

Item 3 – Legal Proceedings

Material legal proceedings pending at December 31, 2014 and developments in those proceedings from that date to the date of this Annual Report are summarized below.

Water Rights Litigation –Mt. Emmons Project

On July 25, 2008, we filed an Application for Finding of Reasonable Diligence with the Colorado Water Court ("Water Diligence Application") concerning the conditional water rights associated with the Mt. Emmons Project (Case No. 2008CW81). The conditional water decree ("Decree") required the Company to file its proposed plan of operations and associated permits with the Forest Service and BLM within six years of entry of the Decree, or within six years of the final determination of the pending patent application, whichever occurred later. The BLM issued the mineral patents on April 2, 2004. Although the issuance of the patents was appealed, on April 30, 2007, the United States Supreme Court made a final determination (by denial of certiorari) upholding BLM's issuance of the mineral patents. The Company filed a plan of operations on March 31, 2010.

On August 11, 2010, High Country Citizen's Alliance, Crested Butte Land Trust and Star Mountain Ranch Association, Inc. ("Opposers") filed a motion for summary judgment alleging that the plan of operations did not comply with the USFS regulations and did not satisfy certain "reality check" limitations contained in the Decree. On November 24, 2010, the District Court Judge denied the Opposers's motion for summary judgment and held that Company had until April 30, 2013 to comply with the reality check provision of the Decree, which is six years after the Supreme Court denied certiorari in the judicial proceeding. On October 10, 2012, the Company filed a Plan of Operations with the USFS in compliance with the reality check provision of the Decree. The question of the adequacy of the Water Diligence Application is pending. We have settled with every Opposer except Crested Butte Land Trust. The claims of Crested Butte land Trust have been referred to the Colorado Water Court for further proceedings.

Brigham Oil & Gas, L.P.

On June 8, 2011, Brigham Oil & Gas, L.P. ("Brigham"), as the operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court with respect to the undistributed suspended royalty funds from this well to protect itself from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham suspended payment of certain royalty proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Energy One owns a working interest, not royalty interest, in this well so no funds owed to Energy One have been withheld.

On January 28, 2013, the District Court Northwest Judicial District issued an Order for Partial Summary Judgment holding that the State of North Dakota as part of its title to the beds of navigable waterways owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners. This issue has been appealed to the North Dakota Supreme Court. Energy One's legal position is aligned with Brigham, who will continue to provide legal counsel in this case for the benefit of all working interest owners.

Quiet Title Action – Dimmit County, TX

On October 4, 2013, Dimmit Wood Properties, Ltd. ("Dimmit") filed a Quiet Title Action against Chesapeake Exploration, LLC ("Chesapeake"), Crimson Exploration Operating, Inc. ("Crimson"), EXCO Operating Company, LP, OOGC America, Inc., Energy One and Liberty Energy, LLC ("Liberty") (jointly referred to as "Defendants") concerning an 800.77 gross acre oil and gas lease ("Lease") located in Dimmit County, Texas. Crimson, Energy One and Liberty received an assignment from Chesapeake of the Lease, in which Energy One has a 30% working interest. Dimmit alleges that the Lease has terminated due to the failure to achieve production in paying quantities. On October 28, 2013, the Defendants filed an answer, asserting that production in paying quantities was achieved in the primary term of the Lease with an existing producing well and that the Lease has remained in good standing and has not terminated. The Defendants also filed Counterclaims against Dimmit, including but not limited to breach of contract. No new wells have been drilled by the Defendants on the Lease. Crimson, Energy One and Liberty filed a declaratory judgment action in the District Court of Dimmit County in 2014 regarding similar allegations relating to a lease on adjacent acreage that was also assigned to those parties by Chesapeake. The lessors in that case are Dr. Darrell Willerson, Sue Willerson and Willerson Energy Partners, L.P. Crimson, Energy One and Liberty are seeking a determination from the court that the lease remains valid and in effect.

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

Market Information

Our common stock is traded on the over-the-counter market, and prices are reported on a "last sale" basis on the Nasdaq Capital Market. Quarterly high and low sale prices follow:

	High	Low
Calendar year ended December 31, 2014		
First Quarter	$4.97	$3.29
Second Quarter	5.00	3.94
Third Quarter	4.42	3.19
Fourth Quarter	2.95	1.17
Calendar year ended December 31, 2013		
First Quarter	$2.50	$1.47
Second Quarter	2.17	1.56
Third Quarter	2.24	1.82
Fourth Quarter	3.83	2.07

Holders

At March 5, 2015 the closing market price was $1.34 per share. On that date, there were approximately 908 shareholders of record, with 28,388,372 shares of common stock issued and outstanding.

Dividends

We did not declare or pay any cash dividends on common stock during fiscal years 2014 and 2013 and do not intend to declare any cash dividends in the foreseeable future. Our ability to pay dividends in the future is subject to limitations under state law and the terms of the Credit Facility, which restricts the ability of Energy One to pay dividends to the Company.

Issuance of Securities in 2014

During 2014, we issued a total of 311,783 shares of common stock. These issuances were comprised of 141,721 shares issued pursuant to the terms of our ESOP, 151,939 shares issued pursuant to the 2001 Incentive Stock Option Plan, 6,011 shares issued pursuant to the 2012 Equity and Performance Incentive Plan and 12,112 shares issued pursuant to the 2008 Stock Option Plan for U.S. Energy Corp. Independent Directors and Advisory Board Members. The ESOP funding represents the minimum required amount during 2014.

Stock Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock for the five years ended December 31, 2014, to that of the cumulative return on a $100 investment in the S&P 500, the NASDAQ Market Index, and the S&P Small Cap 600 Energy Index. The indices are included for comparative purpose only. This graph is not "soliciting material," is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date the Annual Report was filed and irrespective of any general incorporation language in any such filing.

COMPARISON OF CUMULATIVE TOTAL RETURN AMONG U.S. ENERGY CORP., THE S&P 500, THE NASDAQ MARKET INDEX, AND THE S&P SMALL CAP 600 ENERGY INDEX

ITEM 6. SELECTED FINANCIAL DATA

The selected financial data is derived from and should be read with the financial statements included in this Report.

	(In thousands except per share data) Years ended December 31, 2014	2013	2012	2011	2010
Current assets	$7,500	$13,161	$26,015	$41,604	$50,562
Current liabilities	7,966	7,191	13,253	20,937	18,763
Working capital	(466)	5,970	12,762	20,667	31,799
Total assets	123,523	126,801	140,827	162,439	156,016
Long-term obligations[1]	8,162	10,553	11,457	13,532	1,150
Shareholders' equity	107,395	109,057	116,117	126,781	130,688

[1] Includes $1,100 of accrued reclamation costs at December 31, 2014, $812 at December 31, 2013, $686 at December 31, 2012, $510 at December 31, 2011, and $303 at December 31, 2010

	(In thousands except per share data) For the years ended December 31, 2014	2013	2012	2011	2010
Operating revenues	$32,379	$33,647	$32,534	$30,958	$26,548
Loss from continuing operations	(2,488)	(4,846)	(10,209)	(5,216)	(986)
Other income & expenses	397	(2,840)	714	(717)	(332)
Loss before income taxes and discontinued operations	(2,091)	(7,686)	(9,495)	(5,933)	(1,318)
Benefit from income taxes	--	--	44	3,755	1,860
Discontinued operations, net of tax	--	307	(1,794)	(2,629)	(1,314)
Net loss	$(2,091)	$(7,379)	$(11,245)	$(4,807)	$(772)
Per share financial data					
Operating revenues	$1.16	$1.22	$1.18	$1.14	$0.99
Loss from continuing operations	(0.09)	(0.18)	(0.37)	(0.19)	(0.04)
Other income & expenses	0.01	(0.10)	0.03	(0.03)	(0.01)
Gain (loss) before income taxes and discontinued operations	(0.08)	(0.28)	(0.34)	(0.22)	(0.05)
Benefit from income taxes	--	--	--	0.14	0.07
Discontinued operations, net of tax	--	0.01	(0.07)	(0.10)	(0.05)
Net loss per share basic and diluted	$(0.08)	$(0.27)	$(0.41)	$(0.18)	$(0.03)
Basic shares outstanding	27,832,859	27,678,698	27,466,549	27,238,869	26,763,995

Diluted shares outstanding	27,832,859	27,678,698	27,466,549	27,238,869	26,763,995

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

Forward Looking Statements

Statements in this discussion about expectations, plans and future events or conditions are forward looking statements. Actual future results, including oil and natural gas production growth, financing sources, and environmental and capital expenditures, could be materially different depending on a number of factors, such as changes in commodity prices, political or regulatory events, and other matters, including as discussed below. Please see "Cautionary Statement Regarding Forward-Looking Statements" and Item 1A in this Report, which should be carefully considered in reading this section.

General Overview

We are an independent energy company focused on the acquisition and development of oil and gas producing properties in the continental United States. Our business is currently focused in South Texas and the Williston Basin in North Dakota. However, we do not intend to limit our focus to these geographic areas. We continue to focus on increasing production, reserves, revenues and cash flow from operations while managing our level of debt.

We currently explore for and produce oil and gas through a non-operator business model; however, we may operate oil and gas properties for our own account and may expand our holdings or operations into other areas. As a non-operator, we rely on our operating partners to propose, permit and manage wells. Before a well is drilled, the operator is required to provide all oil and gas interest owners in the designated well the opportunity to participate in the drilling costs and revenues of the well on a pro-rata basis. After the well is completed, our operating partners also transport, market and account for all production. As discussed in Item 1. Business, we are in the process of developing operational capabilities and expect to pursue opportunities to acquire operated properties and/or operatorship of existing properties.

We are also involved in the exploration for and development of minerals (molybdenum) through our ownership of the Mt. Emmons Project in Colorado.

Our carrying capitalized dollar amounts in each of these areas at December 31, 2014 and December 31, 2013 were as follows:

	(In thousands)	
	December 31, 2014	December 31, 2013
Proved oil and gas properties	$75,724	$79,444
Unproved oil and gas properties	10,188	7,478
Exploratory wells in progress	2,357	--
Undeveloped mining properties	21,942	20,739
	$110,211	$107,661

Oil & Gas Activities

In 2014, we had the following financial and operational results:

Revenue. In 2014, we recognized revenues from oil and natural gas production of $32.4 million as compared to $33.6 million during the year ended December 31, 2013.

Reserves. At December 31, 2014, our proved reserves were 4,654,944 BOE as compared to 3,855,033 BOE at December 31, 2013. The following table details our proved reserves by state for the years ended December 31, 2014 and 2013:

State	2014	2013	% Change	
Texas				
Oil (Bbls)	478,691	1,098,210	-56	%
Natural Gas (Mcf)	1,158,011	1,027,884	13	%
Equivalent (BOE)	671,692	1,269,524	-47	%
PV-10 (1) (In thousands)	$23,090	$61,187	-62	%
North Dakota				
Oil (Bbls)	3,615,505	2,333,872	55	%
Natural Gas (Mcf)	1,892,268	1,100,521	72	%
Equivalent (BOE)	3,930,882	2,517,292	56	%
PV-10 (1) (In thousands)	$60,156	$51,779	16	%
Louisiana				
Oil (Bbls)	25,544	27,633	-8	%
Natural Gas (Mcf)	160,962	243,505	-34	%
Equivalent (BOE)	52,370	68,217	-23	%
PV-10 (1) (In thousands)	$1,950	$2,116	-8	%
TOTAL				
Oil (Bbls)	4,119,740	3,459,715	19	%
Natural Gas (Mcf)	3,211,241	2,371,910	35	%
Equivalent (BOE)	4,654,944	3,855,033	21	%
PV-10 (1) (In thousands)	$85,196	$115,082	-26	%

(1) The standard mesaure PV-10 calculation is presented in the Supplemental Financial Information on Oil and Natural Gas Exploration, Development and Production Activities section located in Part II, Item 8 of this report. A reconciliation between the PV-10 reserve value and the after tax value is shown in Part I, Item I of this report.

Production. Our 2014 annual production was 465,342 BOE, or 1,275 BOE/d, as compared to 424,933 BOE, or 1,164 BOE/d, in 2013.

Financial flexibility. Our Credit Facility has a maximum loan amount of $100.0 million, a current borrowing base of $24.5 million and a maturity date of July 30, 2017. At December 31, 2014, we had $6.0 million outstanding under the Credit Facility. See "Capital Resources – Wells Fargo Senior Credit Facility" below.

Commodity prices. Our average realized oil price in 2014 was $85.89 per Bbl (excluding the impact of our economic hedges), $4.92 lower than the 2013 price of $90.81. Our average natural gas price realized during 2014 was $4.72 per Mcf, $0.06 per Mcf higher than the 2013 price of $4.66. Commodity prices are affected by changes in market demand, overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. Our financial results are significantly dependent on commodity prices, particularly oil prices, which are beyond our control and have been and are expected to remain volatile. In addition, recent declines in the price of oil have significantly increased the risk of a ceiling test write-down.

Through Energy One, from time to time, we enter into commodity derivative contracts ("hedges"), typically costless collars and fixed price swaps. U.S. Energy is a guarantor of Energy One's obligations under the hedges. The objective of our hedging program is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, such use may limit our ability to benefit from favorable price movements. Energy One may add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions.

The Dodd-Frank Act included provisions generally requiring over-the-counter derivative transactions to be executed through an exchange or centrally cleared. The ultimate effect on our business of rules adopted under the Dodd-Frank Act is currently uncertain. Under CFTC rules we believe our derivative activity will qualify for the commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement if certain requirements are satisfied. However, certain other rules and regulations could require us to post margin in connection with commodity price risk management activities. Although we cannot predict the ultimate effect of additional rules and regulations in this area, they may result in increased costs and cash collateral requirements for the types of derivative instruments we use to manage our financial risks related to volatility in oil prices and could make it impracticable to implement our hedging strategy.

Drilling programs. We have active agreements with several oil and gas exploration and production companies. Our working interest varies by project (and may vary over time depending on the terms of the relevant agreement), but typically ranges from approximately 1% to 48%. These projects may result in numerous wells being drilled over the next three to five years. We are also actively pursuing the potential acquisition of additional exploration, development or production stage oil and gas properties or companies. The following table details our interests in producing wells as of December 31, 2014 and 2013.

	December 31, 2014		2013	
	Gross	Net [(1)]	Gross	Net [(1)]
Williston Basin:				
Productive wells	99.00	10.27	91.00	10.43
Wells being drilled or awaiting completion	6.00	0.02	10.00	0.27
South Texas				
Productive wells	34.00	9.19	19.00	5.23
Wells being drilled or awaiting completion	1.00	0.33	1.00	0.30
Gulf Coast/South Texas:				
Productive wells	3.00	0.56	3.00	0.56
Wells being drilled or awaiting completion	--	--	--	--
Total:				
Productive wells	136.00	20.02	113.00	16.22
Wells being drilled or awaiting completion	7.00	0.35	11.00	0.57

(1) Net working interests may vary over time under the terms of the applicable contracts.

Williston Basin, North Dakota

Rough Rider Prospect. We participate in fifteen 1,280 acre drilling units in the Rough Rider prospect with Statoil Oil & Gas, L.P. ("Statoil"). From August 24, 2009 to December 31, 2014, we have drilled and completed 24 gross (6.39 net) Bakken formation wells and two gross (0.22 net) Three Forks formation wells under the DPA with Statoil.

During the year ended December 31, 2014, we drilled and completed three gross (0.14 net) Bakken formation wells in the Rough Rider prospect. Our net investment in the Rough Rider prospect wells was $1.3 million for the year ended December 31, 2014. Statoil operates all of the wells.

Yellowstone and SEHR Prospects. We participate in twenty-eight gross 1,280 acre spacing units in the Yellowstone and SEHR prospects with Zavanna, LLC ("Zavanna"). Through December 31, 2014, we have drilled and completed 42 gross (3.10 net) Bakken formation wells and eight gross (0.33 net) Three Forks formation wells in these prospects. The wells are operated by Zavanna (18 gross, 2.91 net), Emerald Oil, Inc. (27 gross, 0.34 net), Murex Petroleum (2 gross, 0.13 net), Kodiak Oil & Gas Corp. (2 gross, 0.04 net) and Slawson Exploration Company, Inc. (1 gross, 0.01 net). During the year ended December 31, 2014, we completed 15 gross (0.17 net) wells in the Yellowstone and SEHR prospects. At December 31, 2014, three additional gross (0.02 net) wells had been spud and were in progress.

Our net investment in the Yellowstone and SEHR prospect wells was $1.8 million during the year ended December 31, 2014.

Bakken/Three Forks Asset Package. In 2012, we acquired approximately 400 net acres in 23 drilling units in McKenzie, Williams and Mountrail Counties of North Dakota. In June 2014, we sold our interest in eight of these 23 drilling units (approximately 285.7 net acres) for $12.2 million. At December 31, 2014, there were 23 gross (0.24 net) producing wells in the remaining 15 drilling units.

During the year ended December 31, 2014, our net investment in wells under the remaining drilling units in this program was $84,000.

South Texas (Eagle Ford Shale and Buda Limestone)

Booth-Tortuga and Leona River Prospects. We participate in the Booth-Tortuga and Leona River prospects with Contango Oil & Gas Company ("Contango"). At December 31, 2014, we have 30 gross (8.23 net) producing wells in these prospects, comprised of 16 gross (4.35 net) Buda limestone wells, three gross (0.90 net) Eagle Ford Shale wells and 11 gross (2.98 net) Austin Chalk wells. During the year ended December 31, 2014, we drilled and completed ten gross (3.0 net) Buda limestone wells in the Booth-Tortuga prospect. During 2014, one additional well (0.30 net) was drilled as a vertical pilot well to evaluate the Eagle Ford formation. The wells are operated by Contango (28 gross, 8.08 net) and WCS Oil & Gas Corporation (2 gross, 0.15 net). Our net investment in these wells during the year ended December 31, 2014, including lease acquisition costs in the prospects, was $12.3 million.

Big Wells Prospect. We participate in the Big Wells prospect with U.S. Enercorp. At December 31, 2014, we have two gross (0.30 net) producing Buda limestone wells in this prospect. During the year ended December 31, 2014, we drilled and completed one gross (0.15 net) well in the Big Wells prospect. Our net investment in this well during the year ended December 31, 2014 was $827,000.

Carrizo Creek and South McKnight Prospects. In May 2014, the Company acquired 33.3% of U.S. Enercorp's interest in approximately 12,100 gross (3,384 net) acres in Dimmit County, Texas. The acreage consists of 4,020 gross (1,181 net) acres of primary leasehold acreage and 8,080 gross (2,203 net) acres of farm-in acreage, to be earned through a continuous drilling program. The farm-in acreage had an initial two well commitment and a 12.5% working interest carry for the leaseholder (the "Farmor") in the first 10 wells. After 100% payout of all costs for the first 10 wells that are drilled under the farm-in program, the Farmor will back in for its 12.5% retained working interest in the prospect. U.S. Enercorp retained a 25% working interest back-in after 115% of project payout has been received by the Company. The Company paid $3.9 million to enter into the transaction, which included leasehold and farm-in acquisition costs as well as our proportionate share of drilling costs for the initial test well in the prospect.

Two gross (0.67 net) wells were drilled and completed on the acquired acreage during the year ended December 31, 2014. One additional well (0.33 net) was in progress at December 31, 2014. Our net investment in this acreage and wells through December 31, 2014 was $10.0 million.

Onshore U.S. Gulf Coast

We participate with three different operators in the onshore U.S. Gulf Coast area. At December 31, 2014, we had three gross (0.56 net) producing wells in this region. Our net investment in Gulf Coast wells and properties was $130,000 during the year ended December 31, 2014.

2014 Production Results

The following table provides a regional summary of our production during the year ended December 31, 2014:

	Williston Basin	South Texas	Gulf Coast	Total
2014 Production				
Oil (Bbl)	212,052	117,040	736	329,828
Gas (Mcf)	121,605	272,653	170,591	564,849
NGLs (Bbl)	12,795	28,279	298	41,372
Equivalent (BOE)	245,115	190,761	29,466	465,342
Avg. Daily Equivalent (BOE/d)	671	523	81	1,275
Relative percentage	52.7%	41.0%	6.3%	100%

Other

Minerals (molybdenum). The Mt. Emmons Project is located near Crested Butte, Colorado and includes a total of 160 fee acres, 25 patented and approximately 1,345 unpatented mining and mill site claims, which together approximate 9,853 acres, or over 15 square miles of claims and fee lands. Historical records filed by predecessor owners of the Mt. Emmons Project with the BLM in the 1990's for the application of patented mineral claims, referenced identification of mineral resources of approximately 220 million tons of 0.366% molybdic disulfide (MoS_2) mineralization. A high grade section of the mineralization containing roughly 23 million tons at a grade of 0.689% MoS_2 was also reported. No assurance can be given that these quantities of MoS_2 exist or that the Company will be successful in permitting the property. Our net investment in this property at December 31, 2014 was $21.9 million.

Geothermal. We own a 19.54% interest in SST, a geothermal limited partnership. In 2013, we recorded an equity loss from SST in 2013 of $104,000. Based on historical losses, lack of current marketability of the properties and current market conditions, management determined that the Company's investment in SST was impaired as of December 31, 2013. As a result, the Company recorded an impairment charge of $2.2 million to write off the carrying amount of the investment in SST at December 31, 2013, to zero. We have notified SST that we do not intend to fund any cash calls, which will result in a dilution of our ownership in SST if future cash calls are made.

Comparative Data

The following table provides information regarding selected production and financial information for the quarter ended December 31, 2014 and the immediately preceding three quarters.

	For the Three Months Ended			
	December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
	(in Thousands, except for production data)			
Production (BOE)	101,265	142,484	116,499	105,093
Oil, gas and NGL production revenue	$5,067	$9,928	$9,128	$8,256
Unrealized and realized derivative gain (loss)	$829	$696	$(612)	$(331)
Lease operating expense	$2,585	$2,238	$1,807	$1,250
Production taxes	$467	$790	$779	$722
DD&A	$3,187	$4,621	$3,583	$3,294
General and administrative	$1,390	$2,030	$1,533	$1,606
Mineral holding costs	$166	$439	$205	$300
Water treatment plant	$475	$491	$452	$457
Income (loss) from continuing operations	$(2,334)	$(63)	$56	$250

Results of Operations

Three Months Ended December 31, 2014 Compared with the Three Months Ended December 31, 2013

During the three months ended December 31, 2014, we recorded a net loss after taxes of $2.3 million, or $0.08 per share basic and diluted, as compared to a net loss after taxes of $1.2 million, or $0.04 per share basic and diluted, during the same period of 2013.

Oil and Gas Operations. Oil and gas operations generated an operating loss of $1.2 million during the quarter ended December 31, 2014 as compared to operating income of $3.3 million during the quarter ended December 31, 2013. The following table summarizes production volumes, average sales prices and operating revenues for the three months ended December 31, 2014 and 2013:

	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Production volumes			
Oil (Bbls)	64,777	96,399	(31,622)
Natural gas (Mcf)	112,290	127,933	(15,643)
Natural gas liquids (Bbls)	17,773	5,525	12,248
Equivalent (BOE)	101,265	123,246	(21,981)
Avg. Daily Equivalent (BOE/d)	1,101	1,340	(239)
Average sales prices			
Oil (per Bbl)	$63.70	$87.26	$(23.56)
Natural gas (per Mcf)	3.93	5.05	(1.12)
Natural gas liquids (per Bbl)	28.18	38.55	(10.37)
Equivalent (BOE)	50.04	75.22	(25.18)
Operating revenues (in thousands)			
Oil	$4,126	$8,412	$(4,286)
Natural gas	440	646	(206)
Natural gas liquids	501	213	288
Total operating revenue	5,067	9,271	(4,204)
Oil and gas production expense	(2,585)	(1,393)	(1,192)
Production taxes	(467)	(835)	368
Income before depreciation, depletion and amortization	2,015	7,043	(5,028)
Depreciation, depletion and amortization	(3,187)	(3,744)	557
(Loss) income	$(1,172)	$3,299	$(4,471)

During the three months ended December 31, 2014, we produced 101,265 BOE, or an average of 1,101 BOE/d, as compared to 123,246 BOE and 1,340 BOE/d during the three months ended December 31, 2013. In our South Texas region, production decreased 21%, from 40,010 BOE to 31,565 BOE, between the two periods as a result of production declines in our Buda limestone drilling program. Production in our Bakken region decreased 17%, from 75,146 BOE to 62,663 BOE, between the two periods as a result of normal production declines and lower working interests in wells drilled in this region. We expect these regional production trends to continue. Portions of our natural gas production are sent to gas processing plants to extract from the gas various natural gas liquids ("NGLs") that are sold separately from the remaining natural gas. We sell some of our gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGLs and the remaining natural gas. In the table above, our share of processing costs is classified as oil and gas production expense.

We recognized $5.1 million in revenues during the three months ended December 31, 2014 as compared to $9.3 million during the same period of the prior year. The $4.2 million decrease in revenue is primarily due to lower realized oil prices and lower oil sales volumes in the three months ended December 31, 2014 when compared to the same period in 2013. Lower production volumes are primarily due to declines in production from both Bakken and Buda formation wells.

Our average net realized price (operating revenue per BOE) for the three months ended December 31, 2014 was $50.04 per BOE compared with $75.22 for the same period in 2013. The decrease in our equivalent realized price for production corresponds with lower average oil and natural gas prices in 2014 when compared with the same period in 2013. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin ranged from $15.00 to $19.00 per barrel during the fourth quarter of 2014. Until additional takeaway capacity is available, we expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices.

Oil and gas production expense of $2.6 million for the three months ended December 31, 2014 was comprised of $2.3 million in lease operating expense and $307,000 in workover expense. The $1.2 million increase in total oil and gas production expense in the three months ended December 31, 2014 as compared to the same period in 2013 results from of an increase in lease operating expense of $1.0 million and an increase in workover expense of $192,000.

Our depletion, depreciation and amortization (DD&A) rate for the three months ended December 31, 2014 was $31.47 per BOE compared to $30.38 per BOE for the same period in 2013. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Mt. Emmons and Water Treatment Plant Operations. We recorded $475,000 in costs and expenses for the water treatment plant and $166,000 for holding costs for the Mt. Emmons molybdenum property during the three months ended December 31, 2014. During the three months ended December 31, 2013, we recorded $603,000 in operating costs related to the water treatment plant and $294,000 in holding costs.

General and Administrative. General and administrative expenses decreased by $286,000 during the three months ended December 31, 2014 as compared to general and administrative expenses for the three months ended December 31, 2013. Lower general and administrative costs in 2014 are primarily a result of decreases of $249,000 in compensation expenses, $103,000 in professional services and $28,000 in insurance costs. The decreases were partially offset by increases of $66,000 in contract services and $30,000 in director fees and related options expense.

Other Income and Expenses. We recognized an unrealized and realized derivative gain of $829,000 in the fourth quarter of 2014 compared to a gain of $255,000 for the same period in 2013. The 2014 amount includes a loss on unrealized changes in the fair value of our commodity derivative contracts of $103,000 and a realized cash settlement gain on derivatives of $932,000.

Gain on the sale of assets increased to $84,000 during the quarter ended December 31, 2014 compared to $31,000 during the quarter ended December 31, 2013.

During the three months ended December 31, 2013, we recorded an equity loss of $64,000 from our unconsolidated investment in SST. Additionally, at December 31, 2013, the Company recorded an impairment loss of $2.2 million to fully impair its investment in SST. Subsequently, we no longer record our share of equity in earnings or losses of SST and recorded no equity income or losses related to SST in 2014.

Interest income was $1,000 and $4,000 during the quarters ended December 31, 2014 and 2013, respectively.

Interest expense decreased to $71,000 during the quarter ended December 31, 2014 from $89,000 during the quarter ended December 31, 2013.

Discontinued Operations. During the three months ended December 31, 2013, we recorded a loss of $3,000, net of taxes, from Remington Village. We sold this property in 2013 and had no income or losses from discontinued operations during the three months ended December 31, 2014.

Year Ended December 31, 2014 Compared with the Year Ended December 31, 2013

During the year ended December 31, 2014, we recorded a net loss after taxes of $2.1 million, or $0.08 per share basic and diluted, as compared to a net loss after taxes of $7.4 million, or $0.27 per share basic and diluted, during 2013.

Oil and Gas Operations. Oil and gas operations generated operating income of $7.1 million during the year ended December 31, 2014 as compared to operating income of $9.6 million during the year ended December 31, 2013, excluding a $5.8 million non-cash impairment charge taken on our oil and gas properties during the year ended December 31, 2013. The following table summarizes production volumes, average sales prices and operating revenues for the year ended December 31, 2014 and 2013:

	Year Ended December 31,		Increase
	2014	2013	(Decrease)
Production volumes			
Oil (Bbls)	329,828	343,719	(13,891)
Natural gas (Mcf)	564,849	408,352	156,497
Natural gas liquids (Bbls)	41,372	13,155	28,217
Equivalent (BOE)	465,342	424,933	40,409
Avg. Daily Equivalent (BOE/d)	1,275	1,164	111
Average sales prices			
Oil (per Bbl)	$85.89	$90.81	$(4.92)
Natural gas (per Mcf)	4.72	4.66	0.06
Natural gas liquids (per Bbl)	33.48	40.44	(6.96)
Equivalent (BOE)	69.58	79.18	(9.60)
Operating revenues (in thousands)			
Oil	$28,331	$31,214	$(2,883)
Natural gas	2,663	1,901	762
Natural gas liquids	1,385	532	853
Total operating revenue	32,379	33,647	(1,268)
Oil and gas production expense	(7,880)	(7,130)	(750)
Production taxes	(2,758)	(3,339)	581
Impairment	-	(5,828)	5,828
Income before depreciation, depletion and amortization	21,741	17,350	4,391
Depreciation, depletion and amortization	(14,685)	(13,623)	(1,062)
Income	$7,056	$3,727	$3,329

During the year ended December 31, 2014, we produced 465,342 BOE, or an average of 1,275 BOE/day. In our South Texas region, production increased 148%, from 76,773 BOE to 190,760 BOE, between the two periods as a result of our Buda limestone drilling program. Due to lower oil prices which has resulted in a slower pace of drilling in this region, we currently do not expect this regional production trend to continue; as discussed above, production from this region declined in the fourth quarter of 2014 relative to the same period of the prior year. Production in our Bakken region decreased 22%, from 314,707 BOE to 245,116 BOE, between the two periods as a result of normal production declines and lower working interests in wells drilled in this region. Due to normal production declines, we expect this regional production trend to continue. Portions of our natural gas production are sent to gas processing plants to extract from the gas various natural gas liquids ("NGLs") that are sold separately from the remaining natural gas. We sell some of our gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGLs and the remaining natural gas. In the table above, our share of processing costs is classified as oil and gas production expense.

We recognized $32.4 million in revenues during the year ended December 31, 2014 as compared to $33.6 million during the same period in 2013. The $1.2 million decrease in revenue is primarily due to lower oil sales volumes and lower average oil prices in 2014 as compared to 2013.

Our average net realized price (operating revenue per BOE) for the year ended December 31, 2014 was $69.58 per BOE compared with $79.18 per BOE for the same period in 2013. Due to takeaway constraints, the discount to West Texas Intermediate ("WTI") quoted prices, or differential, for oil prices in the Williston Basin ranged from $13.00 to $21.00 per barrel during 2014. Until additional takeaway capacity is available, we expect this differential to continue (with the amount of the differential varying over time) and that our oil sales revenue will be affected by lower realized prices from this region.

Oil and gas production expense of $7.9 million for the year ended December 31, 2014 was comprised of $7.2 million in lease operating expense and $675,000 in workover expense. The $750,000 increase in total oil and gas production expense in the year ended December 31, 2014 as compared to the same period in 2013 results from of an increase in lease operating expense of $558,000 and an increase in workover expense of $192,000 and is primarily due to an increase in the number of producing wells in 2014 as compared to 2013.

Our depletion, depreciation and amortization (DD&A) rate for the year ended December 31, 2014 was $31.56 per BOE compared to $32.06 per BOE for the same period in 2013. Our DD&A rate can fluctuate as a result of changes in drilling and completion costs, impairments, divestitures, changes in the mix of our production, the underlying proved reserve volumes and estimated costs to drill and complete proved undeveloped reserves.

Mt. Emmons and Water Treatment Plant Operations. We recorded $1.9 million in costs and expenses for the water treatment plant and $1.1 million for holding costs for the Mt. Emmons molybdenum property during the year ended December 31, 2014. During the year ended December 31, 2013, we recorded $1.8 million in operating costs related to the water treatment plant and $1.2 million in holding costs.

General and Administrative Expenses. General and administrative expenses increased by $1.0 million during the year ended December 31, 2014 compared to general and administrative expenses for the year ended December 31, 2013. The increase in general and administrative costs in 2014 is primarily a result of a $200,000 severance payment made to the General Counsel upon his retirement, $500,000 in non-cash accretion expense related to the acceleration of the Chief Operating Officer's executive retirement benefit upon announcement of his plan to retire at the end of 2014, and increases of $295,000 in professional services and $74,000 in director fees and related options expense. The following table details the changes in the Company's general and administrative costs for the year ended December 31, 2014 compared to the year ended December 31, 2013:

	(In thousands) For the years ended December 31,		
	2014	2013	Change
Executive retirement	$599	$99	$500
Severance compensation	200	--	200
Professional services	885	590	295
Director's fees	348	274	74
Travel	146	130	16
Contract services	549	530	19
Bank charges	26	45	(19)
Other compensation	3,206	3,220	(14)
Other costs	600	640	(40)
Total general and administrative costs	$6,559	$5,528	$1,031

Other Income and Expenses. We recognized an unrealized and realized derivative gain of $582,000 in the year ended December 31, 2014 compared to a loss of $1.1 million for the same period in 2013. The 2014 amount includes a gain on unrealized changes in the fair value of our commodity derivative contracts of $266,000 and a realized cash settlement gain on derivatives of $316,000.

During the year ended December 31, 2014, we recorded a gain on the sale of assets of $112,000 from the sale of non-oil and gas related property and equipment. During the year ended December 31, 2013, we recorded a gain on the sale of assets of $760,000, primarily related to the sale of our corporate aircraft and related facilities.

During the year ended December 31, 2013, we recorded an equity loss of $104,000 from our unconsolidated investment in SST. At December 31, 2013, we fully impaired the investment in SST. Subsequently, we no longer record our share of equity in earnings or losses of SST and therefore recorded no equity income or losses related to SST in 2014.

Interest income was $4,000 and $8,000 during the years ended December 31, 2014 and 2013, respectively.

As a result of lower average debt balances, interest expense decreased to $385,000 during the year ended December 31, 2014 from $429,000 during the year ended December 31, 2013.

Discontinued Operations. During the year ended December 31, 2013, we recorded income of $307,000, net of taxes, from Remington Village. We sold this property in the third quarter of 2013 and had no income or losses from discontinued operations during the year ended December 31, 2014.

Year Ended December 31, 2013 Compared with the Year Ended December 31, 2012

During the year ended December 31, 2013, we recorded a net loss after taxes of $7.4 million, or $0.27 per share basic and diluted, as compared to a net loss after taxes of $11.2 million, or $0.41 per share basic and diluted, during the year ended December 31, 2012. Significant components of the changes in results of operations for the year ended December 31, 2013 as compared to the year ended December 31, 2012 were as follows:

Oil and Gas Operations. Before impairment, oil and gas operations produced operating income of $9.6 million during the year ended December 31, 2013 as compared to operating income of $6.9 million during the year ended December 31, 2012. The following table summarizes production volumes, average sales prices and operating revenues for the year ended December 31, 2013 and 2012:

	For the years ended December 31, 2013	2012	Increase (Decrease)
Production volumes			
Oil (Bbls)	343,719	373,531	(29,812)
Natural gas (Mcf)	408,352	347,811	60,541
Natural gas liquids (Bbls)	13,155	13,203	(48)
Equivalent (BOE)	424,933	444,702	(19,769)
Avg. Daily Equivalent (BOE/d)	1,164	1,215	(51)
Average sales prices			
Oil (per Bbl)	$90.81	$82.38	$8.43
Natural gas (per Mcf)	4.66	3.25	1.41
Natural gas liquids (per Bbl)	40.44	47.79	(7.35)
Equivalent (BOE)	79.18	73.16	6.02
Operating revenues (in thousands)			
Oil	$31,214	$30,772	$442
Natural gas	1,901	1,131	770
Natural gas liquids	532	631	(99)
Total operating revenue	33,647	32,534	1,113
Lease operating expense	(7,130)	(7,301)	171
Production taxes	(3,339)	(3,487)	148
Impairment	(5,828)	(5,189)	(639)
Income before depreciation, depletion and amortization	17,350	16,557	793
Depreciation, depletion and amortization	(13,623)	(14,893)	1,270
Income	$3,727	$1,664	$2,063

During the year ended December 31, 2013, we produced 424,933 BOE, or an average of 1,164 BOE/d, as compared to 444,702 BOE and 1,215 BOE/d during the year ended December 31, 2012. Portions of our natural gas production are sent to gas processing plants to extract from the gas various NGLs that are sold separately from the remaining natural gas. We sell some of our gas before processing and some after processing but in both cases receive revenues based on a share of post-processing proceeds from plant sales of the extracted NGLs and the remaining natural gas. In the table above, our share of processing costs is classified as lease operating expenses.

We recognized $33.6 million in revenues during the year ended December 31, 2013 as compared to $32.5 million during the prior year. The $1.1 million increase in revenue is primarily due to higher average realized prices for oil and natural gas in 2013 when compared to 2012, but was partially offset by lower oil sales volumes in 2013. Revenue from oil sales was higher in the year ended December 31, 2013 when compared to 2012, primarily due to increased realized prices for oil. This increase was partially offset by production declines from wells in the Williston Basin and a 35% reduction of our working and net revenue interest upon payout in the first group of six wells drilled with Statoil.

Our average net realized price (operating revenue per BOE) for the year ended December 31, 2013 was $79.18 per BOE compared with $73.16 for 2012. The increase in our equivalent realized price for production corresponds with higher average oil and natural gas prices in 2013 when compared with 2012. Due to takeaway constraints, the discount, or differential, for oil prices in the Williston Basin ranged from $4.17 to $24.16 per barrel during 2013.

Lease operating expenses were $7.1 million and $7.3 million for the years ended December 31, 2013 and 2012, respectively. Lease operating expenses were comprised of $6.3 million in lease operating costs and $846,000 in workover costs for the year ended December 31, 2013. Lease operating expenses were comprised of $5.5 million in lease operating costs and $1.8 million in workover costs for the year ended December 31, 2012.

During the year ended December 31, 2013, the Company recorded a proved property impairment of $5.8 million related to its oil and gas assets. The impairment, which was recorded in the first quarter of 2013, was primarily due to a decline in the price of oil, additional capitalized costs and changes in production. During the year ended December 31, 2012, the Company recorded a proved property impairment of $5.2 million, primarily due to a decline in natural gas prices, higher projected capitalized well costs and higher projected lease operating expenses.

Our depletion, depreciation and amortization (DD&A) rate for the year ended December 31, 2013 was $32.06 per BOE compared to $33.49 per BOE for the same period in 2012.

Mt. Emmons and Water Treatment Plant Operations. We recorded $1.8 million in costs and expenses for the water treatment plant and $1.2 million for holding costs for the Mt. Emmons molybdenum property during the year ended December 31, 2013. During the year ended December 31, 2012, we recorded $2.0 million in operating costs related to the water treatment plant and $921,000 in holding costs.

General and Administrative. General and administrative expenses decreased by $1.1 million during the year ended December 31, 2013 as compared to general and administrative expenses for the year ended December 31, 2012. Lower general and administrative costs in 2013 were primarily a result of reductions of $384,000 in contract services, $253,000 in depreciation expense, $130,000 in compensation expense, $143,000 in travel costs, $50,000 in bank charges, $45,000 in professional services and $30,000 in other operating costs.

Other Income and Expenses. We recognized an unrealized and realized derivative loss of $1.1 million in the year ended December 31, 2013 compared to a gain of $1.1 million in 2012. The 2013 amount includes a loss on unrealized changes in the fair value of our commodity derivative contracts of $737,000 and realized cash settlement losses on derivatives of $338,000.

During the year ended December 31, 2013, we sold our corporate aircraft and related facilities and other miscellaneous equipment. As a result, we recorded a gain on the sale of assets during the period in the amount of $760,000. During the year ended December 31, 2012, we recorded a loss on the sale of assets of $12,000.

We recorded equity losses of $104,000 and $359,000 from the investment in SST during the years ended December 31, 2013 and 2012, respectively. Additionally, in December 2013, the Company recorded an impairment loss of $2.2 million on the investment in SST.

Gain on the sale of marketable securities (shares of Sutter Gold Mining) decreased to $0 during the year ended December 31, 2013 from $82,000 during the year ended December 31, 2012.

Interest income decreased to $8,000 during the year ended December 31, 2013 from $9,000 during the year ended December 31, 2012. The decrease was a result of lower amounts of cash invested in interest bearing instruments during the nine-month period ended December 31, 2013.

As a result of higher average debt balances, interest expense increased to $284,000 during the year ended December 31, 2013 from $203,000 during the year ended December 31, 2012.

Discontinued Operations. We recorded income of $307,000, net of taxes, from Remington Village during the year ended December 31, 2013 and loss of $1.8 million, net of taxes, for the year ended December 31, 2012. The $2.1 million increase in income when comparing the year ended December 31, 2013 to the year ended December 31, 2012 was primarily a result of a $1.9 million non-cash impairment recorded during the year ended December 31, 2012 and was partially offset by a $120,000 loss on the sale of discontinued operations recorded upon closing the sale of Remington Village in September 2013.

Overview of Liquidity and Capital Resources

At December 31, 2014, we had $4.0 million in cash and cash equivalents and our working capital deficit (current assets minus current liabilities) was $466,000. The following table sets forth key liquidity measures for the year ended December 31, 2014 as compared to the year ended December 31, 2013:

	(In thousands)	
	December 31, 2014	December 31, 2013
Current ratio(1)	0.94 to 1	1.83 to 1
Working capital(2)	$(466)	$5,970
Total debt	$6,000	$9,000
Total cash and marketable securities less debt	$(1,965)	$(3,076)
Total stockholders' equity	$107,395	$109,057
Total debt to equity	0.06 to 1	0.08 to 1
Total liabilities to equity	0.15 to 1	0.16 to 1

(1)Current assets divided by current liabilities
(2)Current assets less current liabilities

As discussed below in Capital Resources and Capital Requirements, we project that our capital resources at December 31, 2014, together with cash flow from operations, will be sufficient to fund operations and capital projects through 2015. Given the size of our potential commitments related to our existing inventory of drilling projects, however, our requirements for additional capital could increase significantly during 2015 if we make acquisitions or elect to participate in any currently unanticipated wells. As a result, we may consider drawing down additional debt on our Credit Facility, selling or joint venturing an interest in some of our oil and gas assets, or accessing the capital markets or other alternatives, as we determine how to best fund our capital program.

The principal recurring uncertainty which affects the Company is variable prices for commodities producible from our oil, gas and mineral properties. Significant price swings can have adverse or positive effects on our business of exploring for, developing and producing oil and gas or minerals. Availability of drilling and completion equipment and crews fluctuates with the market prices for oil and natural gas and thereby affects the cost of drilling and completing wells. When prices are low there is typically less exploration activity and the cost of drilling and completing wells is generally reduced. Conversely, when prices are high there is generally more exploration activity and the cost of drilling and completing wells generally increases.

Capital Resources

Potential primary sources of future liquidity include the following:

Oil and Gas Production. At December 31, 2014, we had 136 gross (20.02 net) producing wells. During the year ended December 31, 2014, we received an average of $2.7 million per month from these producing wells with an average operating cost of $657,000 per month (including workover costs) and production taxes of $230,000, for average net cash flows of $1.8 million per month from oil and gas production before non-cash depletion expense. We anticipate that cash flows from oil and gas operations will be lower in 2015 due to significantly lower average oil prices and lower production volumes. Additionally, increased operating costs and workover expenses, declines in production rates, and other factors could further reduce these average monthly cash flow amounts.

Normal production declines and the back-in after payout provisions granted to Statoil, Zavanna, U.S. Enercorp and other partners will decrease the amount of cash flow we receive from these wells. We anticipate drilling more wells with current partners and with others in the future and will continue to search for additional drilling opportunities to replace these oil reserves and cash flows.

Cash on Hand. At December 31, 2014, we had $4.0 million in cash and cash equivalents.

Wells Fargo Senior Credit Facility. In July 2013, we entered into the Second Amendment to the Credit Agreement with Wells Fargo Bank, N.A., providing a $100.0 million senior secured credit facility, with a current borrowing base of $24.5 million and maturity date of July 30, 2017. As of December 31, 2014, we had available borrowings under the Credit Facility of $18.5 million. The ability to maintain and increase this facility and borrow additional funds is dependent on a number of variables, including our proved reserves and assumptions regarding the price at which oil and natural gas can be sold. As the prices of oil and natural gas decline, the value of reserves based on those prices also declines and directly affects our borrowing base. We must comply with certain financial and non-financial covenants under the terms of the credit facility agreement. We were in compliance with all such covenants at December 31, 2014 and at the date of the filing of this report. For further details related to our Credit Facility, please refer to Note I – Other Liabilities and Debt in Part II, Item 8 of this report.

Capital Requirements

Our direct capital requirements during 2015 relate to the funding of our drilling programs, the potential acquisition of prospective oil and gas properties and/or existing production, payment of debt obligations, operating and capital improvement costs relating to the water treatment plant at the Mt. Emmons project and ongoing permitting activities for the Mt. Emmons project and general and administrative costs. We intend to finance our 2015 capital expenditure plan primarily from the sources described above under "Capital Resources". We may be required to reduce or defer part of our 2015 capital expenditures if we are unable to obtain sufficient financing from these sources. We regularly review our capital expenditure budget to assess changes in current and projected cash flows, acquisition opportunities, debt requirements and other factors.

Oil and Gas Exploration and Development. Expenditures for exploration, development and acquisitions of oil and gas properties are the primary use of our capital resources. Our $8.2 million capital expenditure budget for 2015 has been allocated to the expected drilling of four wells located in South Texas. Actual capital expenditures for each regional drilling program are contingent upon timing, well costs and success. If any of our drilling initiatives are not initially successful or progress more slowly than anticipated, funds allocated for that program may be allocated to other initiatives and/or acquisitions in due course. The actual number of gross and net wells could vary in each of these cases.

Mt. Emmons Molybdenum Project. We are responsible for all costs associated with the Mt. Emmons Project, which includes operation of a water treatment plant. Operating costs for the water treatment plant during 2015 are expected to be approximately $150,000 per month. Additionally, we have budgeted $1.7 million for permitting costs, holding costs and water treatment plant capital improvements that are expected to improve the plant's efficiency and reduce costs.

Insurance. We have liability insurance coverage in amounts we deem sufficient and in line with industry standards for the location, stage, and type of our operations. Payment of substantial liabilities in excess of coverage could require diversion of internal capital away from regular business, which could result in diminished operations. We have property loss insurance on all major assets equal to the approximate replacement value of the assets.

Reclamation Costs. We have reclamation obligations with an estimated present value of $946,000 related to our oil and gas wells and $188,000 related to the Mt. Emmons molybdenum property. No reclamation is expected to be performed during the year ended December 31, 2015 unless a well, or wells, are abandoned due to unexpected operational challenges or if a well becomes uneconomic. As the Mt. Emmons project is developed, the reclamation liability is expected to increase. Our objective, upon closure of the proposed mine at the Mt. Emmons project, is to eliminate long-term liabilities associated with the property.

Overview of Cash Flow Activities

The following table presents changes in cash flows between the years ended December 31, 2014 and 2013. The analysis following the table should be read in conjunction with our consolidated statements of cash flows in Part II, Item 8 of this report.

	(In thousands) For the years ended December 31, 2014	2013	Change
Net cash provided by operating activities	$20,752	$17,098	$3,654
Net cash (used in) investing activities	(19,542)	(18,219)	(1,323)
Net cash (used in) financing activities	(3,055)	(10,821)	7,766
Net cash provided by discontinued operations	--	14,972	(14,972)

Operating Activities. Cash provided by operations for the year ended December 31, 2014 increased to $20.8 million as compared to cash provided by operations of $17.1 million for the prior year. This $3.7 million year over year increase in cash from operating activities is primarily related to $4.0 million in overpayments of oil and gas revenue received from a third party operator. We expect these overpayments to be refunded to the operator in 2015. Other changes in operating cash flow are part of the complete discussion of cash provided by operations in "Results of Operations" above.

Investing Activities. Investing activities provided cash during the year ended December 31, 2014 through $11.5 million in proceeds from the sale of oil and gas properties and $109,000 in proceeds from the sale of non-oil and gas property and equipment.

Investing activities consumed cash through the acquisition and development of oil and gas properties in the amount of $29.8 million, $1.2 million from the purchase of property and equipment and $122,000 from a change in the value of restricted investments.

The $1.3 million change in investing activities during the year ended December 31, 2014 as compared to 2013 is primarily a result of: (a) $9.1 million increase in investment in oil and gas properties in 2014 as compared to 2013, (b) $11.5 million in proceeds from the sale of oil and gas properties in 2014 with no similar sales in 2013, (c) $109,000 in proceeds from the sale of property and equipment in 2014 as compared to $2.6 million during 2013, (d) a $74,000 net decrease in the value of restricted investments and (e) a $1.2 million increase in the purchase of property and equipment.

Financing Activities. Financing activities consumed $3.1 million during 2014. The majority of the cash outflow was related to the repayment of debt. Components of cash flow from financing activities in 2013 include the net repayment of debt in the amount of $11.0 million, new borrowings in the amount of $8.0 million and $55,000 in payment of taxes upon issuance of common stock from the exercise of stock options.

In 2013, financing activities consumed $10.8 million. Components of cash flow from financing activities in 2013 include the repayment of debt in the amount of $12.8 million and new borrowings in the amount of $2.0 million.

Critical Accounting Policies and Estimates

The preparation of our consolidated financial statements in conformity with generally accepted accounting principles in the United States, or GAAP, requires our management to make assumptions and estimates that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates under different assumptions or conditions. A summary of our significant accounting policies is detailed in Note B – Summary of Significant Accounting Polices in Part II, Item 8 of this report. We have outlined below those policies identified as being critical to the understanding of our business and results of operations and that require the application of significant management judgment.

Oil and Natural Gas Reserve Estimates. Our estimates of proved reserves are based on quantities of oil and gas reserves which current engineering data indicates are recoverable from known reservoirs under existing economic and operating conditions. Estimates of proved reserves are key elements in determining our depletion expense and our full cost ceiling limitation. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10 percent discount rate to be applied.

Estimates of proved reserves are inherently imprecise because of uncertainties in projecting rates of production and timing of developmental expenditures, interpretations of geological, geophysical, engineering and production data and the quality and quantity of available data. Changing economic conditions also may affect our estimates of proved reserves due to changes in developmental costs and changes in commodity prices that may impact reservoir economics. We utilize independent reserve engineers to estimate our proved reserves as of December 31 of each year and quarterly throughout the year. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with GAAP for the impact of additions and dispositions. Changes in depletion or impairment calculations caused by changes in reserve quantities or net cash flows are recorded in the period the reserve estimates change. For additional information, please see Note F – Supplemental Oil and Gas Information on Oil and Natural Gas Exploration, Development and Production Activities in Part II, Item 8 of this report.

Oil and Natural Gas Properties, Depletion and Full Cost Ceiling Test. We follow the full cost method in accounting for our oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from property disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized.

The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. The capitalized costs are amortized over the life of the reserves associated with the assets, with the amortization being expensed as depletion in the period that the reserves are produced. This depletion expense is calculated by dividing the period's production volumes by the estimated volume of reserves associated with the investment and multiplying the calculated percentage by the sum of the capitalized investment and estimated future development costs associated with the investment. Changes in our reserve estimates will therefore result in changes in our depletion expense per unit. Costs associated with production and general corporate activities are expensed in the period incurred. Unproved property costs not subject to amortization consist primarily of leasehold and seismic costs related to unproved areas. Costs are transferred into the amortization base on an ongoing basis as the properties are evaluated and proved reserves are established or impairment is determined. We will continue to evaluate these properties and costs will be transferred into the amortization base as undeveloped areas are tested. Unproved oil and natural gas properties are not amortized but are assessed, at least annually, for impairment either individually or on an aggregated basis to determine whether we are still actively pursuing the project and whether the project has been proven, either to have economic quantities of reserves or that economic quantities of reserves do not exist.

Under the full cost method of accounting, capitalized oil and gas property costs less accumulated depletion and net of deferred income taxes may not exceed an amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, impairment would be recognized.

Derivative Instruments. We use derivative instruments, typically fixed-rate swaps and costless collars, to manage price risk underlying our oil and gas production. We may also use puts, calls and basis swaps in the future. All derivative instruments are recorded in the consolidated balance sheets at fair value. We offset fair value amounts recognized for derivative instruments executed with the same counterparty. Although we do not designate any of our derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production. These contracts are accounted for using the mark-to-market accounting method and accordingly, we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations.

Our Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties. The master contracts with approved counterparties identify the CEO and the President as the Company representatives authorized to execute trades. Please refer to Note E, Commodity Price Risk Management, in Part II, Item 8 of this report for further discussion.

Mineral Properties. We capitalize all costs incidental to the acquisition of mineral properties. Mineral exploration costs are expensed as incurred. When exploration work indicates that a mineral property can be economically developed as a result of establishing proved and probable reserves, costs for the development of the mineral property as well as capital purchases and capital construction are capitalized and amortized using units of production over the estimated recoverable proved and probable reserves. Costs and expenses related to general corporate overhead are expensed as incurred. All capitalized costs are charged to operations if we subsequently determine that the property is not economical due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource.

Mineral properties at December 31, 2014 and December 31, 2013 reflect capitalized costs associated with the Mt. Emmons Project. We review our investment in the Mt. Emmons Project annually to determine if an impairment has occurred to the carrying value of the property. We have determined that no impairment is needed to the book value of the property at December 31, 2014.

Assets Held for Sale. Assets are classified as held for sale when the Company commits to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

Asset Retirement Obligations. We account for asset retirement obligations under Accounting Standards Codification ("ASC") 410-20. We record the fair value of the reclamation liability on inactive mining properties as of the date that the liability is incurred. We review the liability each quarter and determine if a change in estimate is required as well as accrete the liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. We deduct any actual funds expended for reclamation during the quarter in which it occurs.

Revenue Recognition. We record oil and natural gas revenue under the sales method of accounting. Under the sales method, we recognize revenues based on the amount of oil or natural gas sold to purchasers, which may differ from the amounts to which we are entitled based on our interest in the properties. Gas balancing obligations as of December 31, 2014 were not significant.

Stock Based Compensation. We measure the cost of employee services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date.

We recognize the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. As share-based compensation expense is recognized based on awards ultimately expected to vest, the expense has been reduced for estimated forfeitures based on historical forfeiture rates.

Income Taxes. Based on enacted tax laws, we recognize deferred income tax assets and liabilities for the expected future income tax consequences of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

We recognize deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. Management believes it is more likely than not that such tax benefits will not be realized and a valuation allowance has been provided.

Future Operations

We intend to acquire new oil and gas properties and pursue new business opportunities. Long term, we intend to be prepared to pay the holding and permitting costs associated with the Mt. Emmons Project.

Effects of Changes in Prices

Natural resource operations are significantly affected by changes in commodity prices. As prices for a particular mineral increase, values for that mineral typically also increase, making acquisitions of such properties more costly and sales potentially more valuable. Conversely, a price decline could enhance acquisitions of properties containing those natural resources, but could make sales of such properties more difficult. Operational impacts of changes in mineral commodity prices are common in the natural resource business. Historical and current prices for the Company's two main natural resource participation interests follow:

Oil and Gas. The ten year Cushing, Oklahoma West Texas Intermediate ("WTI") spot price for oil reached a high of $145.31 per barrel during July 2008 and a ten year low of $30.28 per barrel during December 2008. As of December 31, 2014 and December 31, 2013, the Cushing WTI spot prices for oil were $53.45 and $98.17 per barrel, respectively.

The ten year Henry Hub Gulf Coast Natural Gas Spot Price reached a high of $15.39 per MMbtu in December 2005 and the ten year low was $1.82 per MMbtu in April 2012. The prices per MMbtu at December 31, 2014 and December 31, 2013 were $3.14 and $4.31, respectively.

Higher oil and gas prices should positively impact our revenues going forward while lower oil and gas prices will have a negative impact not only on revenues, cash flows and profitability but also may impact ultimate reserve calculations for our wells. If prices as of December 31, 2014 were used to derive the estimated quantity and present value of our reserves, those estimates would have been significantly lower than those included in this report, which are based on a 12-month average price under applicable SEC rules. In addition, recent declines in the price of oil have significantly increased the risk of a ceiling test write-down in future periods. There is no assurance that our projected 2015 investments in oil and gas properties will be profitable.

Molybdenum. The ten year high for dealer molybdenum oxide was $38.00 per pound in June 2005 and the ten year low was $8.03 per pound in April 2009. The mean price of molybdenum oxide at December 31, 2014 and December 31, 2013 was $9.53 per pound and $9.75 per pound, respectively. The price of molybdenum will have a direct impact on the development of the Mt. Emmons Project.

Contractual Obligations

We had three principal categories of contractual obligations at December 31, 2014: Debt to third parties of $6.0 million, executive retirement obligations of $1.3 million and asset retirement obligations of $1.1 million. The debt is related to our oil and gas reserves and bears a weighted average interest rate of 2.66% per annum. This debt was drawn in three separate tranches, each with a term of six months. Principal and accrued interest is due at the end of each respective tranche's six month term. However, this debt can be continued, at our election, if we remain in compliance with the covenants under the Credit Facility through July 30, 2017. The executive retirement liability will be paid out over varying periods starting after the actual projected retirement dates of the covered executives. The asset retirement obligations are expected to be retired during the next 34 years.

The following table shows the scheduled debt payment, projected executive retirement benefits and asset retirement obligations as of December 31, 2014.

	(In thousands) Payments due by period				
	Total	Less than one Year	One to Three Years	Three to Five Years	More than Five Years
Debt obligations	$6,000	$-	$-	$6,000	$--
Executive retirement	1,309	280	526	117	386
Asset retirement obligation	1,133	--	99	130	904
Totals	$8,442	$280	$625	$6,247	$1,290

Item 7A – Quantitative and Qualitative Disclosures About Market Risk

Commodity Risk. Our major market risk exposure is the commodity pricing applicable to our oil and natural gas production. Realized commodity prices received for such production are primarily driven by the prevailing worldwide price for oil and spot prices applicable to natural gas. The market prices for oil and natural gas have been highly volatile and are likely to continue to be highly volatile in the future, which could impact our prospective revenues. A 10% fluctuation in the price received for oil and natural gas production would have had an approximate $3.2 million impact on our 2014 annual revenues.

To mitigate some of our commodity risk, we use derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk. We may also use puts, calls and basis swaps in the future. We do not hold or issue derivative instruments for trading purposes. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, such use may limit our ability to benefit from favorable price movements. We may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of the existing positions.

Through Energy One, we have entered into commodity derivative contracts ("economic hedges") with Wells Fargo, as described below. The derivative contracts are priced using WTI quoted prices. The Company is a guarantor of Energy One's obligations under the economic hedges. Energy One did not have any commodity derivative contracts in place at December 31, 2014.

Commodity derivative contracts are accounted for using the mark-to-market accounting method and accordingly we recognize all unrealized and realized gains and losses related to these contracts currently in earnings and they are classified as gain (loss) on derivative instruments, net in our consolidated statements of operations. The net gain realized by us related to these instruments was $316,000 for the year ended December 31, 2014. We recognized realized a net loss of $338,000 for the year ended December 31, 2013 and a net gain of $21,000 for the year ended December 31, 2012.

Subsequent to December 31, 2014, we entered into one commodity derivative contract as detailed in the table below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price	
Crude Oil Put					
02/01/15 - 04/30/15	Wells Fargo	WTI	500	Put:	$46.00

Interest Rate Risk. At December 31, 2014, we had long-term debt of $6.0 million at a variable rate pursuant to our Credit Facility. The interest rate that we pay on amounts borrowed under the Credit Facility is derived from the Eurodollar rate and a margin that is applied to the Eurodollar rate. The margin that we pay is based upon the percentage of our available borrowing base that we utilize at the beginning of the quarter. At December 31, 2014, the borrowing base for our Credit Facility was $24.5 million. At December 31, 2014 we had utilized $6.0 million, or 24.5%, of the borrowing base. At this level of utilization, the Credit Facility requires us to pay a margin of 2.00%. Our all-in interest rate under the facility at December 31, 2014 was 2.66%. A 10% increase in the Eurodollar rate would equal approximately seven basis points. Such an increase in the Eurodollar rate would increase our annual interest expense by approximately $17,000, assuming amounts borrowed under our Credit Facility equaled our total potential borrowing base of $24.5 million as of December 31, 2014.

Item 8 – Financial Statements and Supplementary Data

Financial statements meeting the requirements of Regulation S-X are included below.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders
U.S. Energy Corp.

We have audited the accompanying consolidated balance sheets of U.S. Energy Corp. and subsidiaries as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated 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 financial position of U.S. Energy Corp. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), U.S. Energy Corp. and subsidiaries' internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013, and our report dated March 11, 2015 expressed an unqualified opinion on the effectiveness of U.S. Energy Corp.'s internal control over financial reporting.

Hein & Associates LLP

Denver, Colorado
March 11, 2015

U.S. ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
ASSETS
(In thousands, except shares)

	December 31, 2014	December 31, 2013
Current assets:		
Cash and cash equivalents	$ 4,010	$ 5,855
Available for sale securities	25	69
Accounts receivable trade	3,177	6,801
Commodity risk management asset	--	14
Other current assets	288	422
Total current assets	7,500	13,161
Oil and gas properties under full cost method,		
Proved oil and properties	147,486	136,521
Unproved oil and gas properties	10,188	7,478
Exploratory wells in progress	2,357	--
less depletion, depreciation and amortization	(71,762)	(57,077)
Net oil and gas properties	88,269	86,922
Undeveloped mining claims	21,942	20,739
Property, plant and equipment, net of accumulated depreciation of $4,404 and $4,135	3,942	4,199
Other assets	1,870	1,780
Total assets	$ 123,523	$ 126,801

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND SHAREHOLDERS' EQUITY
(In thousands, except shares)

	December 31, 2014	December 31, 2013
Current liabilities:		
Accounts payable	$ 7,441	$ 6,167
Accrued compensation	441	580
Commodity risk management liability	--	280
Other current liabilities	84	164
Total current liabilities	7,966	7,191
Noncurrent liabilities:		
Long-term debt, net of current portion	6,000	9,000
Asset retirement obligations	1,133	812
Other accrued liabilities	1,029	741
Total noncurrent liabilities	8,162	10,553
Commitments and contingencies:		
Shareholders' equity:		
Common stock, $.01 par value; unlimited shares authorized; 28,047,661 and 27,735,878 shares issued, respectively	280	277
Additional paid-in capital	123,980	123,510
Accumulated deficit	(16,809)	(14,718)
Other comprehensive loss	(56)	(12)
Total shareholders' equity	107,395	109,057
Total liabilities and shareholders' equity	$ 123,523	$ 126,801

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except share and per share data)

	For the years ended December 31,		
	2014	2013	2012
Revenues:			
Oil sales	$28,331	$31,214	$30,772
Gas sales	2,663	1,901	1,131
NGL sales	1,385	532	631
Total revenues	32,379	33,647	32,534
Operating expenses:			
Oil and gas	10,638	10,469	10,788
Oil and gas depreciation, depletion and amortization	14,685	13,623	14,893
Impairment of oil and gas properties	--	5,828	5,189
Water treatment plant	1,875	1,817	1,978
Mineral holding costs	1,110	1,228	921
General and administrative	6,559	5,528	6,675
Impairment of corporate aircraft	--	--	2,299
Total operating expenses	34,867	38,493	42,743
Loss from operations	(2,488)	(4,846)	(10,209)
Other income and (expenses):			
Realized gain (loss) on risk management activities	316	(338)	21
Unrealized gain (loss) on risk management activities	266	(737)	1,070
Gain (loss) on the sale of assets	112	760	(12)
Equity (loss) in unconsolidated investment	--	(104)	(359)
Impairment of unconsolidated investment	--	(2,160)	--
Gain on sale of marketable securities	--	--	82
Miscellaneous income	84	160	241
Interest income	4	8	9
Interest expense	(385)	(429)	(338)
Total other income (expense)	397	(2,840)	714
Loss before income taxes and discontinued operations	(2,091)	(7,686)	(9,495)

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands except share and per share data)

	For the years ended December 31, 2014	2013	2012
Income taxes:			
Current (provision for)	--	--	(104)
Deferred benefit from	--	--	148
	--	--	44
Loss from continuing operations	(2,091)	(7,686)	(9,451)
Discontinued operations:			
Discontinued operations, net of taxes	--	427	97
Loss on sale of discontinued operations, net of taxes	--	(120)	--
Impairment on discontinued operations, net of taxes	--	--	(1,891)
	--	307	(1,794)
Net loss	$(2,091)	$(7,379)	$(11,245)
Earnings (loss) per share basic and diluted			
Earnings (loss) from continuing operations	$(0.08)	$(0.28)	$(0.34)
Earnings (loss) from discontinued operations	--	0.01	(0.07)
	$(0.08)	$(0.27)	$(0.41)
Weighted average shares outstanding Basic and diluted	27,832,859	27,678,698	27,466,549

The accompanying notes are an integral part of these statements.

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U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF
COMPREHENSIVE INCOME (LOSS)
(In thousands)

	For the years ended December 31,		
	2014	2013	2012
Net (loss):	$(2,091)	$(7,379)	$(11,245)
Other comprehensive (loss) income:			
Marketable securities, net of tax	(44)	(113)	23
Total comprehensive (loss)	$(2,135)	$(7,492)	$(11,222)

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY
(In thousands except share data)

	Common Stock Shares	Amount	Additional Paid-In Capital	Accumulated Deficit	Unrealized Gain (Loss) on Marketable Securities	Total Shareholders' Equity
Balance January 1, 2012	27,409,908	$ 274	$ 122,523	$ 3,906	$ 78	$ 126,781
Net loss	--	--	--	(11,245)	--	(11,245)
Recognized gain on marketable securities	--	--	--	--	(54)	(54)
Unrecognized loss on marketable securities	--	--	--	--	90	90
Unrealized tax effect on on the unrealized gain	--	--	--	--	(13)	(13)
Funding of ESOP	161,624	2	241	--	--	243
Issuance of common stock 2001 stock compensation plan	60,000	1	162	--	--	163
Issuance of common stock from stock options	1,070	--	--	--	--	--
Issuance of common stock from stock warrants	20,000	--	50	--	--	50
Vesting of stock options	--	--	33	--	--	33
Vesting of stock warrants	--	--	69	--	--	69
Balance December 31, 2012	27,652,602	$ 277	$ 123,078	$ (7,339)	$ 101	$ 116,117

The accompanying notes are an integral part of these statements.

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U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY
(continued)
(In thousands except share data)

	Common Stock Shares	Amount	Additional Paid-In Capital	Accumulated Deficit	Unrealized Gain (Loss) on Marketable Securities	Total Shareholders' Equity
Balance December 31, 2012	27,652,602	$ 277	$ 123,078	$ (7,339)	$ 101	$ 116,117
Net loss	--	--	--	(7,379)	--	(7,379)
Unrecognized loss on marketable securities	--	--	--	--	(113)	(113)
Funding of ESOP	53,276	--	200	--	--	200
Issuance of common stock 2001 stock compensation plan	30,000	--	48	--	--	48
Vesting of stock options	--	--	120	--	--	120
Vesting of stock warrants	--	--	64	--	--	64
Balance December 31, 2013	27,735,878	$ 277	$ 123,510	$ (14,718)	$ (12)	$ 109,057

The accompanying notes are an integral part of these statements.

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U.S. ENERGY CORP
STATEMENT OF SHAREHOLDERS' EQUITY
(continued)
(In thousands except share data)

	Common Stock Shares	Amount	Additional Paid-In Capital	Accumulated Deficit	Unrealized Gain (Loss) on Marketable Securities	Total Shareholders' Equity
Balance December 31, 2013	27,735,878	$ 277	$ 123,510	$ (14,718)	$ (12)	$ 109,057
Net loss	--	--	--	(2,091)	--	(2,091)
Unrecognized loss on marketable securities	--	--	--	--	(44)	(44)
Funding of ESOP	141,721	1	208	--	--	209
Issuance of common stock from stock options	157,950	2	(64)	--	--	(62)
Issuance of common stock from stock warrants	12,112	--	8	--	--	8
Vesting of stock options	--	--	229	--	--	229
Vesting of stock warrants	--	--	89	--	--	89
Balance December 31, 2014	28,047,661	$ 280	$ 123,980	$ (16,809)	$ (56)	$ 107,395

The accompanying notes are an integral part of these statements.

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U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31,		
	2014	2013	2012
Cash flows from operating activities:			
Net (loss)	$(2,091)	$(7,379)	$(11,245)
(Gain) loss from discontinued operations includes non-cash impairment of $-0-, $-0-, and $1,891	--	(307)	1,794
Loss from continuing operations	(2,091)	(7,686)	(9,451)
Adjustments to reconcile net loss to net cash provided by operations			
Depreciation, depletion & amortization	14,956	13,898	15,457
Change in fair value of commodity price risk management activities, net	(266)	737	(1,070)
Impairment of oil and gas properties	--	5,828	5,189
Impairment of equity investment	--	2,160	--
Impairment of corporate aircraft	--	--	2,299
Gain on sale of marketable securities	--	--	(82)
Equity loss from Standard Steam	--	104	359
Net change in deferred income taxes	--	--	(60)
(Gain) loss on sale of assets	(112)	(760)	12
Noncash compensation	1,024	452	518
Noncash services	88	64	69
Net changes in assets and liabilities			
Accounts receivable	2,571	(1,619)	315
Income tax receivable	--	--	113
Other current assets	165	8	230
Over payments by operators	3,983	--	--
Accounts payable	909	3,617	(476)
Accrued compensation expense	(436)	172	(336)
Other liabilities	(39)	123	53
Net cash provided by operating activities	20,752	17,098	13,139
Cash flows from investing activities:			
Acquisition & development of oil & gas properties	(29,831)	(20,757)	(42,311)
Acquisition of property and equipment	(1,213)	(42)	(102)
Proceeds from sale of oil and gas properties	11,515	--	21,475
Proceeds from sale of marketable securities	--	--	101
Proceeds from sale of property and equipment	109	2,628	76
Net change in restricted investments	(122)	(48)	(116)
Net cash (used in) investing activities:	(19,542)	(18,219)	(20,877)

The accompanying notes are an integral part of these statements.

U.S. ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	(In thousands) For the years ended December 31,		
	2014	2013	2012
Cash flows from financing activities:			
Issuance of common stock	(55)	-	51
Proceeds from new debt	8,000	2,000	10,000
Repayments of debt	(11,000)	(12,821)	(12,484)
Net cash (used in) financing activities	(3,055)	(10,821)	(2,433)
Net cash provided by operating activities of discontinued operations	--	317	122
Net cash provided by investing activities of discontinued operations	--	14,655	--
Net cash provided by discontinued operations	--	14,972	122
Net (decrease) increase in cash and cash equivalents	(1,845)	3,030	(10,049)
Cash and cash equivalents at beginning of period	5,855	2,825	12,874
Cash and cash equivalents at end of period	$4,010	$5,855	$2,825
Supplemental disclosures:			
Income tax paid	$--	$--	$--
Interest paid	$385	$274	$179
Non-cash investing and financing activities:			
Unrealized gain on marketable securities	$56	$12	$101
Acquisition and development of oil and gas properties through accounts payable	$2,565	$142	$6,202
Net additions to oil and gas properties through asset retirement obligations	$281	$131	$142

The accompanying notes are an integral part of these statements.

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U.S. ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2014, 2013 and 2012

A. BUSINESS ORGANIZATION AND OPERATIONS

U.S. Energy Corp. ("USE", the "Company", "we" or "us") was incorporated in the State of Wyoming on January 26, 1966. U.S. Energy Corp. engages in the acquisition, exploration and development of oil and gas properties and the exploration, holding, sale and/or development of mineral properties. Principal asset interests at December 31, 2014 are in oil and gas, and molybdenum.

B. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Significant estimates include oil and gas reserves used for depletion and impairment considerations, accrued revenue and related receivables, valuation of commodity derivative instruments and the cost of future asset retirement obligations. The Company evaluates its estimates on an on-going basis and bases its estimates on historical experience and on various other assumptions the Company believes to be reasonable under the circumstances. Due to inherent uncertainties, including the future prices of oil and gas, these estimates could change in the near term and such changes could be material.

Principles of Consolidation

The financial statements of USE as of December 31, 2014 include the accounts of USE and its wholly owned subsidiary Energy One, LLC ("Energy One"). The financial statements of USE as of December 31, 2013 and 2012 include the accounts of USE and its then wholly owned subsidiaries Energy One and Remington Village, LLC ("Remington Village"). All inter-company balances and transactions have been eliminated in consolidation. The financial statements as of December 31, 2014, 2013 and 2012 reflect USE's ownership in a geothermal company, Standard Steam Trust LLC ("SST"), which is accounted for using the equity method. The Company recorded an impairment of $2.2 million on the investment in SST during the year ended December 31, 2013, which reduced the carrying amount of our investment in SST to zero. Subsequently, we no longer record our share of equity in earnings or losses. At December 31, 2014 USE's ownership interest in SST was 19.54%.

Cash and Cash Equivalents

USE considers all highly liquid investments with original maturities of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short-term nature of these instruments. USE maintains its cash and cash equivalents in bank deposit accounts which may exceed federally insured limits. USE has not experienced any losses in such accounts and believes the accounts are not exposed to any significant credit risk on cash and cash equivalents.

Marketable Securities

USE categorizes its marketable securities as available-for-sale or held-to-maturity. Increases or decreases in the fair value of available-for-sale securities which are considered temporary are recorded within equity as comprehensive income or losses. Gains or losses as a result of sale are recorded in operations when realized. As of December 31, 2014 and 2013, USE had unrealized gains in the marketable securities before tax effect of $1,000 and $45,000, respectively.

U.S. ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2014, 2013 and 2012
(Continued)

Accounts Receivable

USE determines any required allowance by considering a number of factors including the length of time trade and other accounts receivable are past due and our previous loss history. USE provides reserves for account receivable balances when they become uncollectable. Payments subsequently received on such reserved receivables are credited to the allowance for doubtful accounts. During the years ended December 31, 2014 and 2013, USE recorded $0 in bad debt expense. The balance of accounts receivable at December 31, 2014 and 2013 are primarily related to the sale of oil and gas. Generally, the Company's oil and gas receivables are collected within two months, and the Company has had minimal bad debts. No reserve for uncollectable receivables was booked during the year ended December 31, 2014 or 2013.

Valuation of Equity Method Investment

The Company's investment in SST is evaluated quarterly for possible impairment as applicable in accordance with ASC 323-10-35-32, which provides guidance related to a loss in value of an equity method investment. This evaluation as of December 31, 2013, based on historical losses, current market conditions and forward business plans of SST, resulted in a determination by management that the Company's investment in SST was impaired as of December 31, 2013. As a result, the Company incurred a non-cash impairment charge of $2.2 million to write off the carrying amount of the investment in SST at December 31, 2013 to zero. Future equity losses will not be recorded, however, the Company will resume accounting for the investment in SST under the equity method if SST subsequently reports net income and the Company's share of that net income equals the net losses not recognized during the period in which the equity method was suspended. For additional information about the Company's investment in SST, please refer to Note G – Investment in Standard Steam Trust, LLC.

Restricted Investments

USE accounts for cash deposits held as collateral for reclamation obligations as restricted investments. Maturities or release dates less than twelve months from the end of the reported accounting period are reported as current assets while maturities or release dates in excess of twelve months from report dates are reported as long term assets.

Properties and Equipment

Land, buildings, improvements, machinery and equipment are carried at cost. Depreciation of buildings, improvements, machinery and equipment is provided principally by the straight-line method over estimated useful lives ranging from 3 to 45 years. Following is a breakdown of the lives over which assets are depreciated:

Machinery and Equipment:	
Office Equipment	3 to 5 years
Field Tools and Hand Equipment	5 to 7 years
Vehicles and Trucks	3 to 7 years
Heavy Equipment	7 to 10 years
Buildings and Improvements:	
Service Buildings	20 years
Corporate Headquarters Building	45 years

U.S. ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
DECEMBER 31, 2014, 2013 and 2012
(Continued)

Components of Property and Equipment as of December 31, 2014 and 2013 are as follows:

	(In thousands) December 31, 2014	December 31, 2013
Oil and Gas properties		
Proved	$147,486	$136,521
Unproved	10,188	7,478
Exploratory wells in progress	2,357	--
	160,031	143,999
Less accumulated depreciation depletion and amortization	(71,762)	(57,077)
Net book value	$88,269	$86,922
Mineral properties	$21,942	$20,739
Property, plant and equipment	$8,346	$8,334
Less accumulated depreciation	(4,404)	(4,135)
Net book value	$3,942	$4,199

Oil and Gas Properties

The Company follows the full cost method in accounting for its oil and gas properties. Under the full cost method, all costs associated with the acquisition, exploration and development of oil and gas properties are capitalized and accumulated in a country-wide cost center. This includes any internal costs that are directly related to development and exploration activities, but does not include any costs related to production, general corporate overhead or similar activities. Proceeds received from property disposals are credited against accumulated cost except when the sale represents a significant disposal of reserves, in which case a gain or loss is recognized. The sum of net capitalized costs and estimated future development and dismantlement costs for each cost center is depleted on the equivalent unit-of-production method, based on proved oil and gas reserves. Excluded from amounts subject to depletion are costs associated with unproved properties.

Full Cost Pool – Full cost pool capitalized costs are amortized over the life of production of proven properties. Capitalized costs at December 31, 2014 and 2013 which were not included in the amortized cost pool were $12.5 million and $7.5 million, respectively. These costs consist of exploratory wells in progress and land costs related to unevaluated properties. No capitalized costs related to unproved properties are included in the amortization base at December 31, 2014 and 2013.

Ceiling Test Analysis – Under the full cost method, net capitalized costs are limited to the lower of unamortized cost reduced by the related net deferred tax liability and asset retirement obligations or the cost center ceiling. The cost center ceiling is defined as the sum of (i) estimated future net revenue, discounted at 10% per annum, from proved reserves, based on unescalated average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period and costs, adjusted for contract provisions and financial derivatives that hedge USE's oil and gas revenue and asset retirement obligations, (ii) the cost of properties not being amortized, and (iii)

the lower of cost or market value of unproved properties included in the cost being amortized, reduced by (iv) the income tax effects related to differences between the book and tax basis of the crude oil and natural gas properties. If the net book value reduced by the related net deferred income tax liability and asset retirement obligations exceeds the cost center ceiling limitation, a non-cash impairment charge is required in the period in which the impairment occurs.

We perform a quarterly ceiling test for each of our oil and gas cost centers. There was only one such cost center in 2014. The reserves used in the ceiling test and the ceiling test itself incorporate assumptions regarding pricing and discount rates over which management has no influence in the determination of present value. In arriving at the ceiling test for the year ended December 31, 2014, USE used $94.99 per barrel for oil and $4.35 per MMbtu for natural gas (and adjusted for property specific gravity, quality, local markets and distance from markets) to compute the future cash flows of USE's producing properties. The discount factor used was 10%.

The Company recorded no proved property impairments related to its oil and gas assets during the year ended December 31, 2014. In 2013, we recorded a proved property impairment of $5.8 million related to our oil and gas assets. The impairment was primarily due to a decline in the price of oil, additional capitalized well costs and changes in production. As of December 31, 2014, there were no unproved properties that were considered to be impaired and reclassified to properties being amortized. Management will continue to review the Company's unproved properties based on market conditions and other changes and if appropriate, unproved property amounts may be reclassified to the amortized base of properties within the full cost pool. Recent declines in the price of oil have significantly increased the risk of a ceiling test write-down in future periods.

Wells in Progress - Wells in progress represent the costs associated with unproved wells that have not reached total depth or have not been completed as of period end. They are classified as wells in progress and withheld from the depletion calculation and the ceiling test. The costs for these wells are then transferred to evaluated property when the wells reach total depth and are cased and the costs become subject to depletion and the ceiling test calculation in future periods.

Mineral Properties

We capitalize all costs incidental to the acquisition of mineral properties. Mineral exploration costs are expensed as incurred. When exploration work indicates that a mineral property can be economically developed as a result of establishing proved and probable reserves, costs for the development of the mineral property as well as capital purchases and capital construction are capitalized and amortized using units of production over the estimated recoverable proved and probable reserves. Costs and expenses related to general corporate overhead are expensed as incurred. All capitalized costs are charged to operations if we subsequently determine that the property is not economic due to permanent decreases in market prices of commodities, excessive production costs or depletion of the mineral resource.

Mineral properties at December 31, 2014 and 2013 reflect capitalized costs associated with our Mt. Emmons molybdenum property near Crested Butte, Colorado. Our carrying balance in the Mt. Emmons property at December 31, 2014 and 2013 is as follows:

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	(In thousands)	
	December 31, 2014	December 31, 2013
Costs associated with Mount Emmons beginning of year	$20,739	$ 20,739
Property purchase [1]	1,203	--
Costs at the end of the period	$21,942	$ 20,739

[1]On January 21, 2014, the Company acquired Thompson Creek Metals' ("TCM") 50% interest in 160 acres of fee land in the vicinity of the Mt. Emmons project mining claims for $1.2 million. The property was originally acquired jointly by the Company and TCM in January 2009.

Long-Lived Assets

We evaluate our long-lived assets for impairment when events or changes in circumstances indicate that the related carrying amount may not be recoverable. Impairment calculations are generally based on market appraisals. If estimated future cash flows, on an undiscounted basis, are less than the carrying amount of the related asset, an asset impairment is considered to exist. Changes in significant assumptions underlying future cash flow estimates may have a material effect on our financial position and results of operations.

Assets Held for Sale

In accordance with authoritative accounting guidance regarding property plant and equipment, assets are classified as held for sale when we commit to a plan to sell the assets and there is reasonable certainty that the sale will take place within one year. Upon classification as held for sale, long-lived assets are no longer depreciated or depleted, and a measurement for impairment is performed to determine if there is any excess of carrying value over fair value less costs to sell. Subsequent changes to estimated fair value less the cost to sell will impact the measurement of assets held for sale if the fair value is determined to be less than the carrying value of the assets.

In January 2011, we made the decision to sell our Remington Village multifamily project in Gillette, Wyoming and in September 2012, we made the decision to sell our corporate aircraft and related facilities to reduce overhead costs. All assets classified as assets held for sale at December 31, 2012 were sold in the year ending December 31, 2013. Operations related to Remington Village are shown in discontinued operations on the accompanying consolidated statements of operations. For additional discussion please refer to Note H – Discontinued Operations.

Derivative Instruments

The Company uses derivative instruments, typically costless collars and fixed-rate swaps, to manage price risk underlying its oil and gas production. All derivative instruments are recorded in the consolidated balance sheets at fair value. The Company offsets fair value amounts recognized for derivative instruments executed with the same counterparty. Although the Company does not designate any of its derivative instruments as cash flow hedges, such derivative instruments provide an economic hedge of our exposure to commodity price risk associated with forecasted future oil and gas production.

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These contracts are accounted for using the mark-to-market accounting method and accordingly, the Company recognizes all unrealized and realized gains and losses that are related to these contracts currently in earnings and classifies them as gain (loss) on derivative instruments, net in our consolidated statements of operations. The Company may also use puts, calls and basis swaps in the future.

The Company's Board of Directors sets all risk management policies and reviews the status and results of derivative activities, including volumes, types of instruments and counterparties on a quarterly basis. These policies require that derivative instruments be executed only by the Chief Executive Officer or President. The agreements with approved counterparties identify the Chief Executive Officer and President as the only Company representatives authorized to execute trades. See Note E, Commodity Price Risk Management, for further discussion.

Fair Value of Financial Instruments

The carrying amount of cash equivalents, receivables, other current assets, accounts payable and accrued expenses approximate fair value because of the short-term nature of those instruments. The recorded amounts for short-term and long-term debt approximate the fair market value due to the variable nature of the interest rates on the short-term debt, and the fact that interest rates remain generally unchanged from issuance of the long-term debt.

Asset Retirement Obligations

USE accounts for its asset retirement obligations under FASB ASC 410-20, "Asset Retirement Obligations." USE records the fair value of the reclamation liability on its inactive mining properties and its operating oil and gas properties as of the date that the liability is incurred. USE reviews the liability each quarter and determines if a change in estimate is required, and it accretes the discounted liability on a quarterly basis for the future liability. Final determinations are made during the fourth quarter of each year. USE deducts any actual funds expended for reclamation during the quarter in which it occurs.

The following is a reconciliation of the total liability for asset retirement obligations:

	(In thousands) December 31, 2014	December 31, 2013
Beginning asset retirement obligation	$812	$ 686
Accretion of discount	40	38
Liabilities incurred	310	131
Liabilities settled	(29)	(43)
Ending asset retirement obligation	$1,133	$ 812
Mineral properties	$187	$ 175
Oil and Gas wells	946	637
Ending asset retirement obligation	$1,133	$ 812

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Revenue Recognition

USE derives revenue primarily from the sale of produced oil, gas, and NGLs. The Company reports revenue as the gross amount received before taking into account production taxes and transportation costs, which are reported separately as expenses and are included in oil and gas production expense in the accompanying statements of operations. USE records natural gas and oil revenue under the sales method of accounting. Revenue is recorded in the month that the production is delivered to the purchaser. Payment is generally received between 30 and 90 days after the date of production. At the end of each month, we estimate the amount of production delivered to the purchaser and the price we will receive. USE uses its knowledge of its properties, their historical performance, market prices, and other factors as the basis for these estimates.

USE has exposure to credit risk in the event of nonpayment by our operators, which are all in energy related industries. During 2014, we had three major operators, Contango Oil & Gas Company, Statoil and Zavanna, LLC and which accounted for approximately 38 percent, 28 percent and 20 percent of our total oil, gas and NGL revenues, respectively. During 2013, we had three major operators, Statoil, Zavanna, LLC and Contango Oil & Gas Company which accounted for approximately 38 percent, 32 percent and 18 percent of our total oil, gas and NGL revenues, respectively. During 2012, we had two major operators, Statoil and Zavanna, which accounted for 57 percent and 32 percent of our total oil, gas and NGL revenues, respectively.

Revenues from real estate operations are reported on a gross revenue basis and are recorded at the time the service is provided.

Stock Based Compensation

USE measures the cost of employee and director services received in exchange for all equity awards granted, including stock options, based on the fair market value of the award as of the grant date. USE computes the fair values of its options granted to employees using the Black Scholes pricing model and the following weighted average assumptions:

	For the years ended December 31,		
	2014	2013	2012
Risk-free interest rate	2.06%	1.66%	0.82% to 1.41%
Expected lives (years)	6.0	6.0	5.0 to 6.0
Expected volatility	65.45%	62.59%	61.87% to 63.59%
Expected dividend yield	--	--	--

USE recognizes the cost of the equity awards over the period during which an employee is required to provide service in exchange for the award, usually the vesting period. As share-based compensation expense is recognized based on awards ultimately expected to vest, the expense has been reduced for estimated forfeitures based on historical forfeiture rates.

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Income Taxes

USE recognizes deferred income tax assets and liabilities for the expected future income tax consequences, based on enacted tax laws, of temporary differences between the financial reporting and tax bases of assets, liabilities and carry forwards.

Additionally, USE recognizes deferred tax assets for the expected future effects of all deductible temporary differences, loss carry forwards and tax credit carry forwards. Deferred tax assets are reduced, if deemed necessary, by a valuation allowance for any tax benefits which, based on current circumstances, are not expected to be realized. At December 31, 2014 and 2013, management believed it was more likely than not that such tax benefits would not be realized and a valuation allowance has been provided. For further discussion, please refer to Note J – Income Taxes.

Earnings Per Share

Basic net income (loss) per share is computed based on the weighted average number of common shares outstanding. Common shares held by the ESOP are included in the computation of earnings per share. Total shares held by the ESOP at December 31, 2014, 2013, and 2012 were 949,870, 877,399, and 824,123, respectively.

Diluted net income (loss) per share is calculated by dividing net income or loss by the diluted weighted average common shares outstanding, which includes the effect of potentially dilutive securities. Potentially dilutive securities for this calculation consist of in-the-money outstanding stock options. When there is a loss from continuing operations, all potentially dilutive shares are anti-dilutive and are excluded from the calculation of net income (loss) per share. The treasury stock method is used to measure the dilutive impact of in-the-money stock options.

The following table sets forth the calculations of basic and diluted earnings per share:

	(In thousands except share amounts and per share data) For the years ended December 31,		
	2014	2013	2012
Net (loss)	$(2,091)	$(7,379)	$(11,245)
Basic weighted-average common shares outstanding	27,832,859	27,678,698	27,466,549
Add: dilutive effect of stock options	--	--	--
Diluted weighted-average common shares outstanding	27,832,859	27,678,698	27,466,549
Basic net (loss) per share	$(0.08)	$(0.27)	$(0.41)
Diluted net (loss) per share	$(0.08)	$(0.27)	$(0.41)

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The following table details the weighted-average anti-dilutive securities related to stock options for the years presented:

	For the years ended December 31,		
	2014	2013	2012
Weighted-average anti-dilutive stock options	1,355,195	2,531,202	2,491,746

Recent Accounting Pronouncements

In April 2014, the Financial Accounting Standard Board ("FASB") issued new authoritative accounting guidance related to the recognition and presentation of discontinued operations in the financial statements. The guidance is aimed at reducing the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results. This authoritative accounting guidance is effective for interim and annual periods beginning after December 15, 2014, and is to be applied prospectively. The Company is currently evaluating the provisions of this authoritative guidance and assessing its impact, but does not currently believe it will have a material effect on the Company's financial statements or disclosures.

In May 2014, the FASB issued new authoritative accounting guidance related to the recognition of revenue. This authoritative accounting guidance is effective for the annual period beginning after December 15, 2016, including interim periods within that reporting period, and is to be applied using one of two acceptable methods. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In June 2014, the FASB issued new authoritative accounting guidance related to the recognition of share-based compensation when an award provides that a performance target can be achieved after the requisite service period. This authoritative accounting guidance may be applied either prospectively or retrospectively and is effective for annual periods and interim periods beginning after December 15, 2015. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In August 2014, the FASB issued new authoritative guidance that requires management to evaluate whether there are conditions or events that raise substantial doubt about an entity's ability to continue as a going concern within one year after the date that the entity's financial statements are issued, or within one year after the date that the entity's financial statements are available to be issued, and to provide disclosures when certain criteria are met. This guidance is effective for the annual period ending after December 15, 2016, and for annual periods and interim periods thereafter. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

In January 2015, the FASB issued new authoritative accounting guidance that simplifies income statement presentation by eliminating extraordinary items from GAAP. This guidance is to be applied either prospectively or retrospectively and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early application is permitted provided the guidance is applied from the beginning of the annual year of adoption. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

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In February 2015, the FASB issued new authoritative accounting guidance meant to clarify the consolidation reporting guidance in GAAP. This guidance is to be applied using a retrospective method or a modified retrospective method, as outlined in the guidance, and is effective for annual periods, and interim periods within those annual periods, beginning after December 15, 2015. Early application is permitted. The Company is currently evaluating the provisions of this guidance and assessing its impact on the Company's financial statements and disclosures.

There are no other accounting standards applicable to the Company that have been issued but not yet adopted by the Company as of December 31, 2014, and through the filing date of this report.

C. ACQUISITIONS AND DIVESTITURES

Acquisitions

On May 7, 2014, the Company entered into a Participation Agreement with a private South Texas based oil and gas company ("Seller") to acquire 33% of the Seller's interest in approximately 12,100 gross (3,384 net) acres in Dimmit County, Texas. The acreage consists of 4,020 gross (1,181 net) acres of primary leasehold acreage and 8,080 gross (2,203 net) acres of farm-in acreage, to be earned through a continuous drilling program. The farm-in acreage has an initial two well commitment and a 12.5% working interest carry for the leaseholder (the "Farmor") in the first 10 wells. After 100% payout of all costs for the first 10 wells that are drilled under the farm-in program, the Farmor will back in for its 12.5% retained working interest in the prospect. The Seller also retained a 25% working interest back-in after 115% of project payout has been received by the Company. The Company paid $3.9 million to enter into the transaction, which included leasehold and farm-in acquisition costs as well as our proportionate share of drilling costs for the initial test well in the prospect.

Divestitures

On May 27, 2014, the Company entered into a Purchase and Sale Agreement to sell certain Williston Basin assets. Under the terms of the sale agreement, the Company sold its interest in approximately 285.70 net acres and 16 gross (0.62 net) producing wells in Williams and McKenzie Counties, North Dakota. The transaction closed in June 2014 with an effective date of January 1, 2014. The Company received $12.2 million at closing which included $681,000 in adjustments related to revenue receivable and accounts payable through the date of closing. The $11.5 million balance of the sale proceeds was recorded as a credit to our full cost pool.

D. FAIR VALUE

We follow authoritative guidance regarding fair value measurements for all assets and liabilities measured at fair value. That guidance establishes a fair value hierarchy that prioritizes the inputs the Company uses to measure fair value based on the significance level of the following inputs:

- Level 1 - Quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2 - Quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and model-derived valuations whose inputs or significant value drivers are observable.

- Level 3 - Significant inputs to the valuation model are unobservable.

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Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the nonfinancial assets and liabilities and their placement in the fair value hierarchy levels. We determine our estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted prices in active markets, and quotes from third parties.

The following tables list the Company's assets and liabilities that are measured at fair value and their classification within the fair value hierarchy as of December 31, 2014 and December 31, 2013:

(In thousands)

		Fair Value Measurements at December 31, 2014 Using		
Description	December 31, 2014	(Level 1)	(Level 2)	(Level 3)
Available for sale securities	$25	$25	$ --	$--
Total assets	$25	$25	$ --	$--
Executive retirement program liability	$1,309	$--	$ --	$1,309
Total liabilities	$1,309	$--	$ --	$1,309

		Fair Value Measurements at December 31, 2013 Using		
Description	December 31, 2013	(Level 1)	(Level 2)	(Level 3)
Commodity risk management assets	$ 14	$--	$ 14	$ --
Available for sale securities	69	69	--	--
Total assets	$ 83	$69	$ 14	$ --
Commodity risk management liability	$ 280	$--	$ 280	$ --
Executive retirement program liability	865	--	--	865
Total liabilities	$ 1,145	$--	$ 280	$ 865

The following table summarizes the change in the fair value of our Level 3 fair value measurements for the year ended December 31, 2014.

Change in Level 3 Fair Value Measurements

Description	December 31, 2013	Additions and Payments	Revision of Value	December 31, 2014
Executive retirement program liability	$865	$444	$--	$1,309

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The following table summarizes, by major security type, the fair value and unrealized gain of our investments. The unrealized gain is recorded on the consolidated balance sheet as other comprehensive income, a component of stockholders' equity.

	(In thousands) December 31, 2014		
Description of Securities	Cost	Unrealized Gain	Fair Value
Available for sale securities	$24	$ 1	$ 25
Total	$24	$ 1	$ 25

	December 31, 2013		
Description of Securities	Cost	Unrealized Gain	Fair Value
Available for sale securities	$24	$ 45	$ 69
Total	$24	$ 45	$ 69

Fair Value of Available for Sale Securities

The fair value of available for sale securities is based on quoted market prices obtained from independent pricing services. Accordingly, the Company has classified these instruments as Level 1.

Fair Value of Commodity Derivative Instruments

The Company determines its estimate of the fair value of derivative instruments using a market approach based on several factors, including quoted market prices in active markets, quotes from third parties, the credit rating of the counterparty and the Company's own credit rating. In consideration of counterparty credit risk, the Company assessed the likelihood that the counterparty to the derivative would default by failing to make any contractually required payments. Additionally, the Company considers that it is of substantial credit quality and has the financial resources and willingness to meet its potential repayment obligations associated with the derivative transactions. At December 31, 2013, derivative instruments utilized by the Company consisted of "no premium" collars. The crude oil derivative markets are highly active. Although the Company's derivative instruments are valued using indices, the instruments themselves are traded with third-party counterparties and are not openly traded on an exchange. As such, the Company has classified these instruments as Level 2.

Fair Value of Executive Retirement Program

The executive retirement program is a standalone liability for which there is no available market price, principal market, or market participants. The Company records the estimated fair value of the long-term liability for estimated future payments under the executive retirement program based on the discounted value of estimated future payments associated with each individual in the program. The inputs available for this estimate are unobservable and are therefore classified as Level 3 inputs.

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Fair Value of Financial Instruments

Our other financial instruments include cash and cash equivalents, accounts receivable, accounts payable, other current liabilities and long-term debt. The carrying amount of cash and cash equivalents, accounts receivable, accounts payable and other current liabilities approximate fair value because of their immediate or short-term maturities. The carrying value of our debt approximates its fair market value as it bears interest at variable rates over the term of the loan. The fair value and carrying value of our debt was $6.0 million as of December 31, 2014.

E. COMMODITY PRICE RISK MANAGEMENT

Through our wholly-owned subsidiary Energy One, we have entered into commodity derivative contracts ("economic hedges") with Wells Fargo, as described below. The derivative contracts are priced using West Texas Intermediate ("WTI") quoted prices. The Company is a guarantor of Energy One's obligations under the economic hedges. The objective of utilizing the economic hedges is to reduce the effect of price changes on a portion of our future oil production, achieve more predictable cash flows in an environment of volatile oil and gas prices and to manage our exposure to commodity price risk. The use of these derivative instruments limits the downside risk of adverse price movements. However, there is a risk that such use may limit our ability to benefit from favorable price movements. Energy One may, from time to time, add incremental derivatives to hedge additional production, restructure existing derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of its existing positions. The Company does not engage in speculative derivative activities or derivative trading activities, nor does it use derivatives with leveraged features.

The following table details the fair value of the derivatives recorded in the applicable consolidated balance sheet, by category as of December 31, 2013. There were no derivative contracts in place at December 31, 2014.

		As of December 31, 2013 (in thousands)		
Underlying Commodity	Location on Balance Sheet	Gross amounts of recognized assets and liabilities	Gross amounts offset in the consolidated balance sheet	Net amounts of assets and liabilities presented in the consolidated balance sheet
Crude oil derivative contract	Current assets	$345	$ (331)	$ 14
Crude oil derivative contract	Current liabilities	$611	$ (331)	$ 280

Unrealized gains and losses resulting from derivatives are recorded at fair value on the consolidated balance sheet and changes in fair value are recognized in the unrealized gain (loss) on risk management activities line on the consolidated statement of operations. Realized gains and losses resulting from the contract settlement of derivatives are recognized in the commodity price risk management activities line on the consolidated statement of operations. The following table summarizes the unrealized and realized derivative (gain) loss presented in the accompanying statements of operations:

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	(In thousands) For the years ended December 31,		
	2014	2013	2012
Realized derivative (loss) gain	$316	$(338)	$21
Unrealized derivative (loss) gain	$266	$(737)	$1,070
Total realized and unrealized derivative (loss) gain	$582	$(1,075)	$1,091

F. SUPPLEMENTAL FINANCIAL INFORMATION ON OIL AND NATURAL GAS EXPLORATION, DEVELOPMENT AND PRODUCTION ACTIVITIES

Capitalized Costs

The following table presents information regarding USE's net costs incurred in the purchase of proved and unproved properties, and in exploration and development activities:

	(In thousands)	
	December 31, 2014	December 31, 2013
Proved oil and gas properties	$147,486	$136,521
Unproved	10,188	7,478
Exploratory wells in progress	2,357	--
	$160,031	$143,999

USE's DD&A per equivalent BOE was $31.56 in 2014, $32.06 in 2013, and $33.49 in 2012.

Undeveloped properties as of December 31, 2014 include costs incurred in the following years:

	(In thousands)			
	Acquisitions	Exploration	Development	Total
2010	$103	$ --	$ --	$103
2011	4,015	--	--	4,015
2012	271	--	--	271
2013	2,067	--	--	2,067
2014	3,732	--	--	3,732
Total	$10,188	$ --	$ --	$10,188

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Costs incurred in oil and natural gas property acquisition, exploration and development activities are summarized below:

	(In thousands) Year Ended December 31,		
	2014	2013	2012
Property acquisition costs:			
Proved	$552	$445	$2,987
Unproved	4,167	1,760	1,416
Exploration costs	14,791	9,138	10,943
Development costs	8,037	9,403	20,134
Total costs incurred	$27,547	$20,746	$35,480

Results of Operations

Results of operations from oil and natural gas producing activities are presented below:

	(In thousands) For the years ending December 31,		
	2014	2013	2012
Revenues	$32,379	$33,647	$32,534
Operating expenses	10,638	10,469	10,788
Depreciation, depletion and amortization	14,685	13,623	14,893
Impairment	--	5,828	5,189
	25,323	29,920	30,870
Operating income	$7,056	$3,727	$1,664

Oil and Natural Gas Reserves (Unaudited)

Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can reasonably be expected to be recovered through existing wells with existing equipment and operating methods.

Proved oil and natural gas reserve quantities at December 31, 2014, 2013 and 2012 and the related discounted future net cash flows before income taxes are based on the estimates prepared by Cawley, Gillespie & Associates, Inc. Such estimates have been prepared in accordance with guidelines established by the Securities and Exchange Commission.

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USE's net ownership interests in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves, all of which are located in the continental United States, are summarized below:

December 31, 2014	Oil (BBLS)	Natural Gas or NGL (MCFE)
Beginning of year	3,459,713	2,371,908
Revisions of previous quantity estimates	(262,570)	802,241
Extensions, discoveries and improved recoveries	1,583,292	1,006,659
Purchase of reserves in place	--	--
Sales of reserves in place	(330,871)	(156,482)
Production	(329,828)	(813,081)
End of year	4,119,736	3,211,245
Proved developed reserves at end of year	1,754,668	1,892,446

December 31, 2013	Oil (BBLS)	Natural Gas or NGL (MCFE)
Beginning of year	2,613,643	1,798,088
Revisions of previous quantity estimates	(162,957)	382,690
Extensions, discoveries and improved recoveries	1,352,746	678,412
Purchase of reserves in place	--	--
Sales of reserves in place	--	--
Production	(343,719)	(487,282)
End of year	3,459,713	2,371,908
Proved developed reserves at end of year	1,875,528	1,701,282

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Standardized Measure (Unaudited)

The standardized measure of discounted future net cash flows relating to USE's ownership interests in proved oil and natural gas reserves as of year-end is shown below:

	(In thousands) Year Ended December 31,		
	2014	2013	2012
Future cash inflows	$381,156	$330,245	$237,148
Future costs:			
Production	(149,450)	(129,392)	(96,616)
Development	(70,770)	(37,739)	(21,461)
Future income tax expense	(12,719)	(14,500)	(8,483)
Future net cash flows	148,217	148,614	110,588
10% discount factor	(66,328)	(43,761)	(39,571)
Standardized measure of discounted future net cash flows	$81,889	$104,853	$71,017

Future cash flows are computed by applying average prices per barrel of oil and per MMbtu of natural gas at the first day of each month in the 12-month period prior to the end of the reporting period to year-end quantities of proved oil and natural gas reserves. Prices used in computing year end 2014, 2013 and 2012 future cash flows were $94.99/barrel, $96.78/barrel and $94.71/barrel, respectively, for oil and $4.35/MMbtu, $3.67/MMbtu and $2.757/MMbtu for natural gas, respectively, in each case adjusted for regional price differentials and other factors. Future operating expenses and development costs are computed primarily by USE's independent petroleum engineers by estimating the expenditures to be incurred in developing and producing USE's proved oil and natural gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions.

Future income taxes are based on year-end statutory rates, adjusted for the tax basis of oil and gas properties and available applicable tax assets. A discount factor of 10% was used to reflect the timing of future net cash flows. The standardized measure of discounted future net cash flows is not intended to represent the replacement cost or fair market value of USE's oil and natural gas properties. An estimate of fair value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, and a discount factor more representative of the time value of money and the risks inherent in reserve estimates.

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Change in Standardized Measure (Unaudited)

Changes in standardized measure of future net cash flows relating to proved oil and natural gas reserves are summarized below:

	(In thousands) Year Ended December 31,		
	2014	2013	2012
Balance at beginning of period	$104,853	$71,017	$62,191
Sales of oil and gas, net of production costs	(21,741)	(23,179)	(21,747)
Net change in prices and production costs	(17,376)	2,543	(4,548)
Changes in estimated future development costs	(1,869)	(6,414)	(9,706)
Extensions and discoveries	14,706	54,360	23,297
Purchase of reserves in place	--	--	2,573
Sale of reserves in place	(13,339)	--	(13,573)
Revisions of previous quantity estimates	(4,815)	(2,961)	(5,927)
Previously estimated development costs incurred during the period	7,175	8,344	22,808
Net change in income taxes	6,924	(4,245)	7,261
Accretion of discount	10,090	7,647	7,254
Changes in production rates, timing and other	(2,719)	(2,259)	1,134
Balance at end of period	$81,889	$104,853	$71,017

Sales of oil and natural gas, net of oil and natural gas operating expenses, are based on historical pretax results. Extensions and discoveries and the changes due to revisions in standardized variables are reported on a pretax discounted basis.

G. INVESTMENT IN STANDARD STEAM TRUST, LLC

USE's ownership interest in SST, a Denver, Colorado based private geothermal resource acquisition and development company, was 19.54% at December 31, 2013. The Company recorded an impairment of $2.2 million on the investment in SST during the year ended December 31, 2013, which reduced the carrying amount of our investment in SST to zero. Subsequently, we no longer record our share of equity in earnings or losses and recorded no income or loss from SST during the year ended December 31, 2014. The Company recorded an equity loss in unconsolidated investment related to SST of $104,000 during the year ended December 31, 2013.

H. DISCONTINUED OPERATIONS

On September 11, 2013, the Company completed the sale of the Remington Village Apartment Complex in Gillette Wyoming ("Remington Village") to an affiliate of the Miller Frishman Group, LLC for $15.0 million. The $9.5 million balance on the commercial note relating to Remington Village was paid in full at closing. After deduction of payment of the note, commission and other closing costs, the net proceeds to the Company were approximately $5.0 million. Upon closing this transaction, a loss of $120,000 was recorded on the sale of discontinued of operations. Due to the sale of Remington Village in 2013, the Company did not record any income or losses from discontinued real estate operations for the year ended December 31, 2014.

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The Company's real estate operations for the years ending December 31, 2013 and 2012 have been classified as discontinued operations in the current financial statements. Results of discontinued operations for the years ended December 31, 2014, 2013, and 2012 were as follows:

	(In thousands) For the years ending December 31,		
	2014	2013	2012
Revenues	$--	$1,271	$2,037
Operating expenses	--	844	1,885
Impairment	--	--	2,955
	--	844	4,840
Income (loss) before income taxes	--	427	(2,803)
Income tax benefit	--	--	1,009
Net income (loss) from discontinued operations	$--	$427	$(1,794)

Because Remington Village was classified as an asset held for sale, scheduled depreciation of $660,000 for 2013 and $896,000 for 2012 was not recorded.

I. OTHER LIABILITIES AND DEBT

As of December 31, 2014 and 2013, USE had current and long term liabilities associated with the following funding commitments:

	(In thousands)	
	December 31, 2014	December 31, 2013
Other liabilities and debt:		
Other liabilities		
Deferred rent	$14	$ 11
Remington Escrow	--	95
Employee health insurance self funding	70	58
	$84	$ 164
Other long term liabilities:		
Accrued executive retirement costs	$1,029	$ 741
Debt:		

Credit Facility - collateralized by		
oil and gas reserves, at 2.66%	$6,000	$ 9,000
Less current portion	--	--
Totals	$6,000	$ 9,000

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Wells Fargo Reserve Credit Facility

On July 30, 2010, USE established a Senior Secured Revolving Credit Facility (the "Facility") to borrow up to $100 million from a syndicate of banks, financial institutions and other entities, including BNP Paribas, who was replaced as a lender by Wells Fargo Bank, NA ("Wells Fargo") on April 24, 2012. At present, Wells Fargo is the only lender under the Facility. In the future, the facility may include other members of a lending syndicate (the "Lenders") as provided for in the Facility. Wells Fargo also is the administrative agent for the Facility, which is governed by the following documents: Credit Agreement; Mortgage, Deed of Trust, Assignment of As-Extracted Collateral, Security Agreement, Fixture Filing and Financing Statement (the "Mortgage"); and Guaranty and Pledge Agreement (the "Guaranty"), which are referred to below together as the "Facility Documents." The following summarizes the principal provisions of the Facility as set forth in the Facility Documents. The summary is qualified by reference to the complete text of the documents.

USE's wholly-owned subsidiary, Energy One, is the borrower under the Facility. USE has assigned to Energy One all of its rights, title and interest in certain oil and gas properties and equipment related thereto, rights under various operating agreements, proceeds from sale of production and from sale or other disposition of the properties. Borrowings under the Facility are collateralized by Energy One's oil and gas producing properties. USE also has unconditionally and irrevocably guaranteed Energy One's performance of its obligations under the Credit Agreement, including without limitation Energy One's payment of all borrowings and related fees thereunder.

From time to time until expiration of the Facility (July 30, 2017), if Energy One is in compliance with the Facility Documents, Energy One may borrow, pay, and re-borrow funds from the Lenders, up to an amount equal to the Borrowing Base, which was initially established at $12 million. The Borrowing Base is redetermined semi-annually, taking into account updated reserve reports prepared by USE's independent reserve engineers. Any proposed increase in the Borrowing Base will require approval by all Lenders in the syndicate (presently only Wells Fargo), and any proposed Borrowing Base decrease will require approval by Lenders holding not less than two-thirds of outstanding loans and loan commitments.

Interest is payable quarterly at the greater of the Prime Rate, the Federal Funds Effective Rate (plus 0.5%), and the adjusted LIBO rate (as those terms are defined in the Credit Agreement) for the three prior months, plus, an additional 2.00% to 3.00%, depending on the amount of the loan relative to the Borrowing Base. Interest rates on outstanding loans are adjustable each day by Wells Fargo as administrative agent. Energy One may prepay principal at any time without premium or penalty, but all outstanding principal will be due on July 30, 2017. If there is a decrease in the Borrowing Base, the excess of outstanding loans over the Borrowing Base will be due over the six months following the redetermination. We pay Wells Fargo a fee each time the Borrowing Base is increased.

In addition, on a quarterly basis, Energy One will pay Wells Fargo, for the account of each Lender (as applicable), a commitment fee of 0.50% of the unused amount of each Lender's lending commitment, computed daily until July 30, 2017.

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Energy One is required to comply with customary affirmative covenants and with certain negative covenants. The principal negative financial covenants (measured at various times as provided in the Credit Agreement) do not permit (i) the Interest Coverage Ratio (Interest Expense to EBITDAX) to be less than 3.0 to 1; (ii) Total Debt to EBITDAX to be greater than 3.5 to 1; and (iii) the Current Ratio (current assets plus unused lender commitments under the Borrowing Base) to be less than 1.0 to 1.0. EBITDAX is defined in the Credit Agreement as Consolidated Net Income, plus non-cash charges. At December 31, 2013, Energy One was in compliance with all the affirmative and negative covenants.

If Energy One fails to pay interest or principal when due, or fails to comply with the covenants in the Credit Agreement (after a reasonable cure period, if applicable), Wells Fargo as Administrative Agent may (and shall, if requested by the Majority Lenders (Lenders holding not less than 2/3rds of the outstanding loan principal), declare the loans immediately due, and foreclose on Energy One's assets and enforce USE's guaranty.

As of December 31, 2014, the Borrowing Base was $24.5 million and we had borrowed $6.0 million under the Facility. The Company's outstanding balance under the Credit Agreement as of the date of this report is $6.0 million.

Real Estate Notes

On May 5, 2011, USE borrowed $10.0 million from a commercial bank against Remington Village. This debt was retired on September 11, 2013 when Remington Village was sold.

J. INCOME TAXES

The provision for income taxes is composed of the following:

	(in thousands) Years ended December 31,		
	2014	2013	2012
Current income tax expense (benefit)			
Federal	$--	$ --	$--
State	--	--	--
	$--	$ --	$--
Deferred income tax expense (benefit)			
Federal	$--	$ --	$(1,093)
State	--	--	(64)
	$--	$ --	$(1,157)

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The effective income tax rate differs from the U.S. Federal Statutory income tax rate due to the following:

	(in thousands) Years ended December 31,		
	2014	2013	2012
Federal statutory income tax rate	$(711)	$(2,509)	$(4,164)
State income taxes, net of federal benefit	(34)	(158)	(245)
Incentive stock options	79	43	12
Percentage depletion carryover	(129)	(174)	(177)
Valuation allowance	612	2,717	3,512
Other	183	81	(95)
	$--	$--	$(1,157)

The components of deferred tax assets and liabilities as of December 31, 2014 and 2013 are as follows:

	December 31,	
	2014	2013
Deferred tax assets:		
Net operating loss	$10,382	$6,930
Derivative instruments	--	96
Asset retirement obligation	404	294
Stock based compensation	248	228
Deferred compensation	439	385
Alternative minimum tax credit	706	706
Contribution carryover	42	37
Equity investments	629	643
Percentage depletion carryover	2,402	2,421
	$15,252	$11,740
Deferred tax liabilities:		
Property and equipment	(8,351)	(5,446)
State tax	(3)	(9)
Marketable securities	--	(16)
	$(8,354)	$(5,471)
Net deferred tax assets (liabilities)	6,898	6,269
Less: Valuation Allowance	(6,898)	(6,269)
Deferred tax liability	$--	$--

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During the year ended December 31, 2014, deferred tax assets increased $3.5 million and deferred tax liabilities increased by $2.9 million. The change in net deferred tax assets was an increase of $629,000 compared to the previous year. This resulted in a net deferred asset of $6.9 million, which is fully offset by a valuation allowance.

USE has net operating loss carryovers as of December 31, 2014 of $32.4 million for federal income tax purposes and $29.6 million for financial reporting purposes. The difference of $2.8 million relates to tax deductions for compensation expense for financial reporting purposes for which the benefit will not be recognized until the related deductions reduce taxes payable. The net operating loss carryovers may be carried back two years and forward twenty years from the year the net operating loss was generated. The net operating losses may be used to offset taxable income through 2033. In addition, USE has alternative minimum tax credit carry-forwards of $706,000 which are available to offset future federal income taxes over an indefinite period.

The statute of limitations is closed for the tax years through 2010.

USE adopted the applicable provisions of ASC 740 to recognize, measure, and disclose uncertain tax positions in the financial statements. Under ASC 740, tax positions must meet a "more-likely-than-not" recognition threshold to be recognized. During the year ended December 31, 2014, no adjustments were recognized for uncertain tax positions. USE recognizes interest and penalties related to uncertain tax positions in income tax expense (benefit). No interest or penalties related to uncertain tax positions have been accrued.

K. SEGMENTS AND MAJOR CUSTOMERS

During the years ended December 31, 2014, 2013, and 2012, USE, for financial reporting purposes, operated two business segments, the exploration for and sale of oil and gas, and mining. Our operating segments are reflected in the tables below:

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	(In thousands) For the years ended December 31,		
	2014	2013	2012
Revenues:			
Oil and gas	$32,379	$33,647	$32,534
Total revenues	32,379	33,647	32,534
Operating expenses:			
Oil and gas	25,323	29,920	30,870
Mineral properties	2,985	3,045	2,899
Total operating expenses	28,308	32,965	33,769
Interest expense:			
Oil and gas	368	264	169
Mineral properties	--	12	24
Total interest expense	368	276	193
Operating income (loss)			
Oil and gas	$6,688	$3,463	$1,495
Mineral properties	(2,985)	(3,057)	(2,923)
Operating income (loss) from identified segments	3,703	406	(1,428)
General and administrative expenses	(6,559)	(5,673)	(9,109)
Add back interest expense	368	276	193
Other revenues and expenses	397	(2,695)	849
(Loss) before income taxes and discontinued operations	$(2,091)	$(7,686)	$(9,495)
Depreciation depletion and amortization expense:			
Oil and gas	$14,685	$13,623	$14,893
Mineral properties	123	126	127
Corporate	148	149	437
Total depreciation expense	$14,956	$13,898	$15,457

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	(In thousands) December 31,		
	2014	2013	2012
Assets by segment			
Oil and gas	$92,020	$97,418	$93,839
Mineral	21,942	20,739	20,747
Corporate	9,561	8,644	26,241
Total assets	$123,523	$126,801	$140,827

L. SHAREHOLDERS' EQUITY

Stock Option Plans

Employee Stock Option Plans. In December 2001, the Board of Directors adopted (and the shareholders subsequently approved) the U.S. Energy Corp. 2001 Incentive Stock Option Plan (the "2001 ISOP") for the benefit of USE's employees. The 2001 ISOP (amended with the approval of the shareholders in 2004 and 2007) reserved for issuance 25% of USE's shares of common stock issued and outstanding at any time. The 2001 ISOP had a term of 10 years and expired on December 6, 2011. Options issued under the 2001 ISOP remain exercisable until their expiration date under the terms of the 2001 ISOP.

In June 2012, the Board of Directors adopted (and the shareholders approved) the U.S. Energy Corp. 2012 Equity and Performance Incentive Plan (the "2012 Equity Plan") for the benefit of USE's employees. The 2012 Equity Plan reserved for issuance 1,200,000 shares of USE's common stock. The 2012 Equity Plan has a term of 10 years.

A summary of the Employee Stock Option Plans activity in all plans for the years ended December 31, 2014, 2013 and 2012 is as follows:

	Year ended December 31,					
	2014		2013		2012	
	Employee Options	Weighted Average Exercise Price	Employee Options	Weighted Average Exercise Price	Employee Options	Weighted Average Exercise Price
Outstanding at beginning of the period	2,500,949	$ 3.60	2,259,282	$ 3.80	2,318,399	$ 3.94
Granted	--	$ --	270,000	$ 2.08	150,000	$ 2.32
Forfeited	(3,333)	$ 2.08	--	$ --	(10,000)	$ 2.32
Expired	--	$ --	(28,333)	$ 4.68	(194,950)	$ 4.47
Exercised	(400,203)	$ 2.46	-	$ -	(4,167)	$ 2.52
Outstanding at period end	2,097,413	$ 3.82	2,500,949	$ 3.60	2,259,282	$ 3.80
Exercisable at period end	1,949,080	$ 3.95	2,137,619	$ 3.85	2,119,282	$ 3.90

Weighted average fair value of options granted during

the period	$ --	$ 1.20	$ 1.30

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During the year ended December 31, 2014, a total of 400,203 options were exercised by employees by the payment of $1,000 in cash and the surrender or withholding of 228,047 shares valued at $982,000. An additional 14,206 shares valued at $63,000 were withheld for the payment of taxes due upon the exercise of non-qualified options. No employee options were exercised during the year ended December 31, 2013. During the year ended December 31, 2012, a total of 4,167 options were exercised by employees by the withholding of 3,097 shares valued at $10,000. The aggregate intrinsic value of options exercised was $743,000 in 2014, $0 in 2013 and $4,000 in 2012.

Option related compensation expense is recognized over the vesting period of the options and is calculated using the Black Scholes option pricing model. USE initially assumed no forfeitures, but has subsequently reduced the cumulative expense based on historical forfeitures. The total expense associated with employee stock options for the years ended December 31, 2014, 2013 and 2012 was $229,000, $120,000 and $33,000, respectively. As of December 31, 2014, there was $124,000 of total unrecognized expense related to unvested stock options, which is being amortized through 2016.

The following table summarizes information about employee stock options outstanding and exercisable at December 31, 2014:

Grant Price Range	Employee Options Outstanding at December 31, 2014	Weighted average remaining contractual life in years	Weighted average exercise price	Employee Options exercisable at December 31, 2014	Weighted average exercise price
$2.08	270,000	8.74	$ 2.08	166,668	$ 2.08
$2.09 - $2.32	123,333	7.53	$ 2.32	78,332	$ 2.32
$2.33 - $2.52	405,312	3.73	$ 2.52	405,312	$ 2.52
$2.53 - $3.86	273,768	0.79	$ 3.86	273,768	$ 3.86
$3.87 - $4.97	1,025,000	2.57	$ 4.97	1,025,000	$ 4.97
	2,097,413	3.65	$ 3.82	1,949,080	$ 3.95

The following table sets forth the number of options available for grant as well as the intrinsic value of the options outstanding and exercisable at:

	At December 31,		
	2014	2013	2012
Available for future grant	790,000	790,000	1,060,000
Aggregate intrinsic value of options outstanding	$--	$1,661,000	$--
Aggregate intrinsic value of options exercisable	$--	$1,073,000	$--

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Director Option Plan. In June 2008, the Board of Directors adopted (and the shareholders subsequently approved) the 2008 Stock Option Plan for U.S. Energy Corp. Independent Directors and Advisory Board Members (the "2008 SOP") for the benefit of USE's non-employee directors and advisory board members. The 2008 SOP reserved for issuance 1.0% of USE's shares of common stock issued and outstanding at any time. The 2008 SOP has a term of 10 years and expires on June 27, 2018.

As of December 31, 2014, there were 178,666 director options outstanding to purchase shares of USE's common stock. USE values these options using the Black-Scholes option pricing model and expenses that value over various terms based on the nature of the award. Activity for the years ended December 31, 2014, 2013 and 2012 for director options is presented in the following table:

	Year ended December 31,					
	2014		2013		2012	
	Director Options	Weighted Average Exercise Price	Director Options	Weighted Average Exercise Price	Director Options	Weighted Average Exercise Price
Outstanding at beginning of the period	146,000	$ 2.93	150,000	$ 3.05	210,000	$ 3.10
Granted	60,000	$ 3.77	36,000	$ 2.08	80,000	$ 2.78
Forfeited	--	$ --	--	$ --	--	$ --
Expired	--	$ --	(40,000)	$ 2.60	(120,000)	$ 3.05
Exercised	(27,334)	$ 2.53	-	$ -	(20,000)	$ 2.52
Outstanding at period end	178,666	$ 3.28	146,000	$ 2.93	150,000	$ 3.05
Exercisable at period end	82,333	$ 3.30	56,668	$ 3.46	63,335	$ 3.01
Weighted average fair value of options granted during the period		$ 2.27		$ 1.20		$ 1.59

During the year ended December 31, 2014, a total of 27,334 options were exercised by outside directors by the payment of $8,000 in cash and the withholding of 15,000 shares valued at $61,000. No director options were exercised during the year ended December 31, 2013. During the year ended December 31, 2012, a total of 20,000 director options were exercised by the payment of $50,000 in cash. The aggregate intrinsic value of options exercised was $45,000 in 2014, $0 in 2013 and $17,000 in 2012. The total expense associated with director stock options for the years ended December 31, 2014, 2013 and 2012 was $89,000, $64,000 and $69,000, respectively. As of December 31, 2014, there was $147,000 of total unrecognized expense related to unvested stock options, which is being amortized through 2017.

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The following table summarizes information about director options outstanding and exercisable at December 31, 2014:

Grant Price Range	Director Options Outstanding at December 31, 2014	Weighted average remaining contractual life in years	Weighted average exercise price	Director Options exercisable at December 31, 2014	Weighted average exercise price
$2.08	27,000	8.50	$ 2.08	9,000	$ 2.08
$2.09 - $2.32	6,666	7.53	$ 2.32	3,333	$ 2.32
$2.33 - $2.52	10,000	3.73	$ 2.52	10,000	$ 2.52
$2.53 - $2.85	45,000	7.23	$ 2.85	30,000	$ 2.85
$2.86 - $4.19	80,000	8.90	$ 3.88	20,000	$ 4.19
$4.20 - $5.04	10,000	5.48	$ 5.04	10,000	$ 5.04
	178,666	7.88	$ 3.28	82,333	$ 3.30

These options are held by current and former directors of USE.

The following table sets forth the number of options available for grant as well as the intrinsic value of the options outstanding and exercisable at:

	At December 31,		
	2014	2013	2012
Available for future grant	101,811	131,359	126,526
Aggregate intrinsic value of options outstanding	$--	$142,000	$--
Aggregate intrinsic value of options exercisable	$--	$35,000	$--

USE has computed the fair values of its employee and director options using the Black Scholes pricing model and the following weighted average assumptions:

	For the years ended December 31,		
	2014	2013	2012
Risk-free interest rate	2.06%	1.66%	0.82% to 1.41%
Expected lives (years)	6.0	6.0	5.0 to 6.0
Expected volatility	65.45%	62.59%	61.87% to 63.59%
Expected dividend yield	--	--	--

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Employee Stock Ownership Plan

The Board of Directors of USE adopted the U.S. Energy Corp. 1989 Employee Stock Ownership Plan ("ESOP") in 1989, for the benefit of all USE's employees. Employees become eligible to participate in the ESOP after one year of service which must consist of at least 1,000 hours worked. After the employee becomes a participant in the plan, he or she must have a minimum of 1,000 hours of service in each plan year to be considered for allocations of funding from USE. Employees become 20% vested after three years of service and increase their vesting by 20% each year thereafter until such time as they are fully vested after seven years of service.

An employee's total compensation paid, which is subject to federal income tax, up to an annual limit of $260,000 for the year ended December 31, 2014, $255,000 for the year ended December 31, 2013 and $250,000 for the year ended December 31, 2012, is the basis for computing how much of the total annual funding is contributed into his or her personal account. An employee's compensation divided by the total eligible compensation paid to all plan participants is the percentage that each participant receives on an annual basis. USE funds 10% of all eligible compensation annually in the form of common stock and may fund up to an additional 15% to the plan in common stock. As of December 31, 2014, all shares of USE's stock that have been contributed to the ESOP have been allocated and are vested.

During the year ended December 31, 2014, the Board of Directors of USE approved a contribution of 141,721 shares to the ESOP at the price of $1.48 for a total expense of $209,000. This compares to contributions to the ESOP during the years ended December 31, 2013 and 2012 of 53,276 and 161,624 shares to the ESOP at prices of $3.76 and $1.50 per share, respectively. The expense for the contributions during the years ended December 31, 2013 and 2012 were $200,000 and $243,000, respectively.

M. COMMITMENTS, CONTINGENCIES AND OTHER

Legal Proceedings

From time to time, we are party to certain legal actions and claims arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on our financial position or results of operations. Following are currently pending legal matters:

Water Rights Litigation –Mt. Emmons Project

On July 25, 2008, we filed an Application for Finding of Reasonable Diligence with the Colorado Water Court ("Water Diligence Application") concerning the conditional water rights associated with the Mt. Emmons Project (Case No. 2008CW81). The conditional water decree ("Decree") required the Company to file its proposed plan of operations and associated permits with the Forest Service and BLM within six years of entry of the Decree, or within six years of the final determination of the pending patent application, whichever occurred later. The BLM issued the mineral patents on April 2, 2004. Although the issuance of the patents was appealed, on April 30, 2007, the United States Supreme Court made a final determination (by denial of certiorari) upholding BLM's issuance of the mineral patents. The Company filed a plan of operations on March 31, 2010.

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On August 11, 2010, High Country Citizen's Alliance, Crested Butte Land Trust and Star Mountain Ranch Association, Inc. ("Opposers") filed a motion for summary judgment alleging that the plan of operations did not comply with the USFS regulations and did not satisfy certain "reality check" limitations contained in the Decree. On November 24, 2010, the District Court Judge denied the Opposers's motion for summary judgment and held that Company had until April 30, 2013 to comply with the reality check provision of the Decree, which is six years after the Supreme Court denied certiorari in the judicial proceeding. On October 10, 2012, the Company filed a Plan of Operations with the USFS in compliance with the reality check provision of the Decree. The question of the adequacy of the Water Diligence Application is pending. We have settled with every Opposer except Crested Butte Land Trust. The claims of Crested Butte land Trust have been referred to the Colorado Water Court for further proceedings.

Brigham Oil & Gas, L.P.

On June 8, 2011, Brigham Oil & Gas, L.P. ("Brigham"), as the operator of the Williston 25-36 #1H Well, filed an action in the State of North Dakota, County of Williams, in District Court, Northwest Judicial District, Case No. 53-11-CV-00495 to interplead to the court with respect to the undistributed suspended royalty funds from this well to protect itself from potential litigation. Brigham became aware of an apparent dispute with respect to ownership of the mineral interest between the ordinary high water mark and the ordinary low water mark of the Missouri River. Brigham suspended payment of certain royalty proceeds of production related to the minerals in and under this property pending resolution of the apparent dispute. Energy One owns a working interest, not royalty interest, in this well so no funds owed to Energy One have been withheld.

On January 28, 2013, the District Court Northwest Judicial District issued an Order for Partial Summary Judgment holding that the State of North Dakota as part of its title to the beds of navigable waterways owns the minerals in the area between the ordinary high and low watermarks on these waterways, and that this public title excludes ownership and any proprietary interest by riparian landowners. This issue has been appealed to the North Dakota Supreme Court. Energy One's legal position is aligned with Brigham, who will continue to provide legal counsel in this case for the benefit of all working interest owners.

Quiet Title Action – Dimmit County, TX

On October 4, 2013, Dimmit Wood Properties, Ltd. ("Dimmit") filed a Quiet Title Action against Chesapeake Exploration, LLC ("Chesapeake"), Crimson Exploration Operating, Inc. ("Crimson"), EXCO Operating Company, LP, OOGC America, Inc., Energy One and Liberty Energy, LLC ("Liberty") (jointly referred to as "Defendants") concerning an 800.77 gross acre oil and gas lease ("Lease") located in Dimmit County, Texas. Crimson, Energy One and Liberty received an assignment from Chesapeake of the Lease, in which Energy One has a 30% working interest. Dimmit alleges that the Lease has terminated due to the failure to achieve production in paying quantities. On October 28, 2013, the Defendants filed an answer, asserting that production in paying quantities was achieved in the primary term of the Lease with an existing producing well and that the Lease has remained in good standing and has not terminated. The Defendants also filed Counterclaims against Dimmit, including but not limited to breach of contract. No new wells have been drilled by the Defendants on the Lease. Crimson, Energy One and Liberty filed a declaratory judgment action in the District Court of Dimmit County in 2014 regarding similar allegations relating to a lease on adjacent acreage that was also assigned to those parties by Chesapeake. The lessors in that case are Dr. Darrell Willerson, Sue Willerson and Willerson Energy

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Partners, L.P. Crimson, Energy One and Liberty are seeking a determination from the court that the lease remains valid and in effect.

Mining Permits

The Mt. Emmons molybdenum property is located on fee property within the boundary of USFS land. Although mining of the mineral resource will occur on the fee property, associated ancillary activities will occur on USFS land. USE submitted a full mine plan of operations in part to satisfy the requirements of the conditional water rights decree on October 10, 2012. Under the procedures mandated by National Environmental Protection Act ("NEPA"), the USFS will prepare an environmental analysis in the form of an Environmental Assessment and/or and Environmental Impact Statement to evaluate the predicted environmental and social economic impacts of the proposed development and mining of the Mt. Emmons molybdenum property. The NEPA process provides for public review and comment of the proposed plan.

Obtaining and maintaining the various permits for the mining operations at Mt. Emmons will be complex, time-consuming, and expensive. Changes in a mine's design, production rates, quality of material mined, and many other matters, often require submission of the proposed changes for agency approval prior to implementation. In addition, changes in operating conditions beyond our control, or changes in agency policy and Federal and State law, could further affect the successful permitting of the mine operations.

Although USE believes that the plan of operations for Mt. Emmons will ultimately be approved by the USFS, this cannot be guaranteed. Moreover, the timing and cost, and ultimate success of the mining operation, cannot be predicted.

401(K) Plan

The Board of Directors of USE adopted the U.S. Energy Corp. 401(K) Plan in 2004. USE matches 50% of an employee's salary deferrals up to a maximum contribution per employee of $4,000 annually. USE expensed $48,000, $46,000, and $54,000 for the years ended December 31, 2014, 2013 and 2012, respectively, related to these contributions.

Executive Officer Compensation

Executive Retirement Plan. On October 20, 2005, the Board of Directors adopted an Executive Retirement Policy (the "Retirement Plan") for the then Chairman/CEO, President/COO and CFO/Treasurer/V.P. Finance. Under the terms of the Retirement Plan, upon retirement, the executive will receive payments equaling 50% of the greater of (i) the amount of compensation the officer received as base cash pay on his/her final regular pay check or (ii) the average annual pay rate, less all bonuses, he/she received over the last five years of his/her employment with Company. To be eligible for this benefit, the executive officer must have served in one of the designated executive offices for 15 years, reached the age of 60 and been an employee of USE on December 31, 2010. During 2007, the Board of Directors voted unanimously to fund the retirement benefit for the then active officers who qualified under the plan. The funding is held in a separate trust account that is managed by an independent trustee and is subject only to the claims of creditors in the event of insolvency of USE. At December 31, 2014, USE had funded the executive retirement account with the amount calculated by a third party actuary, of $1.3 million, which is recorded as Other Long Term Assets. Additional amounts will be deposited annually until each executive's 60th birthday.

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On June 30, 2011, the CFO/Treasurer/V.P. Finance retired. During the years ended December 31, 2014, 2013 and 2012 that former officer received annual payments of $122,000 from the Retirement Plan. In addition, pursuant to the former CFO/Treasurer/V.P. Finance's employment contract, USE agreed to pay for health insurance for the executive and his spouse from his date of retirement until he becomes eligible for Medicare.

On December 31, 2014, the President/COO retired. Upon announcement of his retirement, the Board of Directors voted unanimously to waive the minimum age eligibility requirement for this officer. As a result, this former officer will receive annual payments of $152,000 beginning January 1, 2015 through December 31, 2019. In addition, pursuant to the former President/COO's employment contract, USE agreed to pay for health insurance for the executive and his spouse for a period of 18 months from his date of retirement.

Compensation expense for executives under the Retirement Plan for the years ended December 31, 2014, 2013 and 2012 was $599,000, $99,000, and $80,000, respectively. The total accrued liability for executive retirement under all plans at December 31, 2014, 2013, and 2012 was $1.3 million, $865,000, and $903,000, respectively.

Health Insurance Retirement Benefit. Pursuant to employment agreements with the current CEO and CFO, USE has agreed to pay for health insurance for the retiring executive and his spouse for a period of 18 months from the date of retirement.

2001 Stock Compensation Plan. In December 2001, the Board of Directors adopted (and the shareholders subsequently approved) the 2001 Stock Compensation Plan (the "2001 SCP") to compensate its executive officers. The 2001 SCP terminated on April 20, 2013 with the shareholder approval of the 2012 Equity Plan at the 2012 annual meeting. The last shares issued under the 2001 SCP were issued in April 2013. Under the plan, 20,000 shares were issued annually to each officer during his employment. During the years ended December 31, 2013 and 2012, USE collectively issued 30,000 and 60,000 shares of stock to these officers, respectively. In consideration of this agreement, USE agreed to pay all taxes due on the shares granted to the officers.

Operating Leases

USE is the lessor of portions of the office buildings and building improvements that it owns. USE occupies the majority of its main office building. The leases are accounted for as operating leases and provide for minimum monthly receipts of $5,000 through December 31, 2015. Rental income under the agreements was $95,000, $96,000, and $170,000 for the years ended December 31, 2014, 2013 and 2012, respectively. Future minimum receipts for non-cancelable operating leases are $76,000 for the year ended December 31, 2015.

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N. SELECTED QUARTERLY FINANCIAL DATA (Unaudited)

	(In thousands except per share data) Three Months Ended December 31, 2014	September 30, 2014	June 30, 2014	March 31, 2014
Operating revenues	$5,067	$9,928	$9,128	$8,256
Operating income (loss)	$(3,203)	$(681)	$769	$627
Income (loss) before income tax and discontinued operations	$(2,334)	$(63)	$56	$250
Benefit from (provision for) income taxes	$--	$--	$--	$--
Discontinued operations, net of tax	$--	$--	$--	$--
Net income (loss)	$(2,334)	$(63)	$56	$250
Income (loss) per share, basic				
Continuing operations	$(0.08)	$--	$--	$0.01
Discontinued operations	--	--	--	--
	$(0.08)	$--	$--	$0.01
Basic weighted average shares outstanding	27,905,940	27,905,940	27,785,280	27,738,083
Income (loss) per share, diluted				
Continuing operations	$(0.08)	$--	$--	$0.01
Discontinued operations	--	--	--	--
	$(0.08)	$--	$--	$0.01
Diluted weighted average shares outstanding	27,905,940	27,905,940	28,237,883	28,142,253

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	(In thousands except per share data) Three Months Ended			
	December 31, 2013	September 30, 2013	June 30, 2013	March 31, 2013
Operating revenues	$9,271	$8,582	$7,915	$7,879
Operating income (loss)	$581	$403	$151	$(6,125)
Income (loss) before income tax and discontinued operations	$(1,217)	$(706)	$367	$(6,130)
Benefit from (provision for) income taxes	$--	$--	$--	$--
Discontinued operations, net of tax	$(3)	$(128)	$206	$232
Net income (loss)	$(1,220)	$(834)	$573	$(5,898)
Income (loss) per share, basic				
Continuing operations	$(0.04)	$(0.03)	$0.01	$(0.22)
Discontinued operations	--	--	0.01	0.01
	$(0.04)	$(0.03)	$0.02	$(0.21)
Basic weighted average shares outstanding	27,682,602	27,682,602	27,682,272	2,766,710
Income (loss) per share, diluted				
Continuing operations	$(0.04)	$(0.03)	$0.01	$(0.22)
Discontinued operations	--	--	0.01	0.01
	$(0.04)	$(0.03)	$0.02	$(0.21)
Diluted weighted average shares outstanding	27,682,602	27,682,602	27,682,272	27,667,102

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	(In thousands except per share data) Three Months Ended December 31, 2012	September 30, 2012	June 30, 2012	March 31, 2012
Operating revenues	$8,038	$7,639	$8,522	$8,335
Operating (loss)	$(5,898)	$(2,675)	$(957)	$(679)
Income (loss) before income tax and discontinued operations	$(6,079)	$(3,155)	$624	$(833)
Benefit from (provision for) income taxes	$(1,302)	$1,285	$(379)	$388
Discontinued operations, net of tax	$(548)	$(75)	$(1,235)	$64
Net (loss)	$(7,929)	$(1,945)	$(990)	$(381)
Income (loss) per share, basic				
Continuing operations	$(0.27)	$(0.07)	$0.01	$(0.01)
Discontinued operations	(0.02)	--	(0.05)	--
	$(0.29)	$(0.07)	$(0.04)	$(0.01)
Basic weighted average shares outstanding	27,475,813	27,468,355	27,460,483	27,438,584
Income (loss) per share, diluted				
Continuing operations	$(0.27)	$(0.07)	$0.01	$(0.01)
Discontinued operations	(0.02)	--	(0.05)	--
	$(0.29)	$(0.07)	$(0.04)	$(0.01)
Diluted weighted average shares outstanding	27,475,813	27,468,355	27,460,483	27,438,584

O. SUBSEQUENT EVENTS

Subsequent to December 31, 2014, we entered into one commodity derivative contract as detailed in the table below:

Settlement Period	Counterparty	Basis	Quantity (Bbls/day)	Strike Price
Crude Oil Put				
02/01/15 - 04/30/15	Wells Fargo	WTI	500	Put: $46.00

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

None

Item 9A. Controls and Procedures

Effectiveness of Disclosure Controls and Procedures

We are required to maintain disclosure controls and procedures (as defined by Rules 13a-15(e) and 15d-15(e) under the Exchange Act) that are designed to ensure that required information is recorded, processed, summarized and reported within the required timeframe, as specified in the rules of the SEC. Our disclosure controls and procedures are also designed to ensure that information required to be disclosed is accumulated and communicated to management, including our Chief Executive Officer and Chief Financial Officer, to allow timely decisions regarding required disclosures.

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2014 and, based on this evaluation, our Chief Executive Officer and Chief Financial Officer have concluded that our disclosure controls and procedures were effective as of December 31, 2014.

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f). Internal control over financial reporting is a process designed by, or under the supervision of, our Chief Executive Officer and Chief Financial Officer, and effected by our Board, management and other personnel, 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.

Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Forward looking statements regarding the effectiveness of internal controls during future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies and procedures may deteriorate.

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2014. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework in 2013. Based on our assessment, we believe that, as of December 31, 2014, our internal control over financial reporting was effective based on those criteria.

Our internal control over financial reporting as of December 31, 2014, has been audited by Hein & Associates LLP, the independent registered public accounting firm who also audited our consolidated financial statements. Hein & Associates LLP's report on our internal control over financial reporting appears on page 124 of this Annual Report.

Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting that occurred during the quarter ended December 31, 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Shareholders
U.S. Energy Corp.

We have audited U.S. Energy Corp. and subsidiaries' internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013. U.S. Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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. A company's internal control over financial reporting includes those policies and procedures that (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (c) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

In our opinion, U.S. Energy Corp. and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission in 2013.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of U.S. Energy Corp. and subsidiaries as of December 31, 2014 and 2013 and the related consolidated statements of operations, comprehensive loss, shareholders' equity, and cash flows for each of the three years in the period ended December 31, 2014 and our report dated March 11, 2015 expressed an unqualified opinion.

Hein & Associates LLP
Denver, Colorado

March 11, 2015

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Item 9B – Other Information

None

PART III

In the event a definitive proxy statement containing the information being incorporated by reference into this Part III is not filed within 120 days of December 31, 2014, we will file such information under cover of a Form 10-K/A.

Item 10 – Directors, Executive Officers and Corporate Governance

The information required by Item 10 with respect to directors and certain executive officers is incorporated herein by reference to our Proxy Statement for the Meeting of Shareholders to be held on June 19, 2015, under the captions "Proposal 1: Election of Directors", "Filing of Reports under Section 16(a)", and "Business Experience of Directors, Nominees and Officers". The other information required by Item 10 is also incorporated by reference herein to such Proxy Statement.

USE has adopted a Code of Ethics. A copy of the Code of Ethics will be provided to any person without charge upon written request addressed to Bryon G. Mowry, Secretary, 877 North 8th West, Riverton, Wyoming 82501.

Information Concerning Executive Officers Who Are Not Directors

Bryon G. Mowry is not a director of the Company. Mr. Mowry (age 56) has been the Corporate Secretary of the Company since October 1, 2014. Mr. Mowry has been employed by the Company and its subsidiaries since 1995 and served as Controller until 2011 when he was promoted to Principal Accounting Officer. He serves at the will of the board of directors. There are no understandings between Mr. Mowry and any other person pursuant to which he was named an officer. He has no family relationships with any of the other executive officers or directors of the Company. During the past five years, Mr. Mowry has not been involved in any Reg. S-K Item 401(f) proceeding.

Steven D. Richmond is not a director of the Company. Mr. Richmond (age 44) has been Chief Financial Officer of the Company since September 7, 2012. Mr. Richmond has been employed by the Company and its subsidiaries since 1992 and served as Controller and Assistant Controller for the Company since 2003. He serves at the will of the board of directors. There are no understandings between Mr. Richmond and any other person pursuant to which he was named an officer. He has no family relationships with any of the other executive officers or directors of the Company. During the past five years, Mr. Richmond has not been involved in any Reg. S-K Item 401(f) proceeding.

Item 11 - Executive Compensation

The information required by Item 11 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 19, 2015, under the captions "Executive Compensation" and "Non-Employee Director Compensation".

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

The information required by Item 12 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 19, 2015, under the caption "Principal Holders of Voting Securities" and "Ownership by Officers and Directors".

Item 13 - Certain Relationships and Related Transactions, and Director Independence

The information required by Item 13 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 19, 2015, under the caption "Certain Relationships and Related Transactions."

Item 14 - Principal Accounting Fees and Services

The information required by Item 14 is incorporated herein by reference to the Proxy Statement for the Meeting of Shareholders to be held on June 19, 2015, under the caption "Principal Accountant Fees and Services".

Glossary of Oil and Gas Terms

The following are abbreviations and definitions of certain terms commonly used in the oil and gas industry and in this report. The definitions of proved developed reserves, proved reserves and proved undeveloped reserves have been abbreviated from the applicable definitions contained in Rule 4-10(a) of Regulation S-X.

3-D seismic. The method by which a three dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do conventional surveys and contribute significantly to field appraisal, development and production.

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

Bcfe. One billion cubic feet of natural gas equivalent. In reference to natural gas, natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

Boe. A barrel of oil equivalent is determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquid.

Completion. The installation of permanent equipment for the production of oil or natural gas. Completion of the well does not necessarily mean the well will be profitable.

Developed Acreage. The number of acres, which are allocated or assignable to producing wells or wells capable of production.

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 Well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion of an oil or gas well.

Exploratory Well. A well drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir.

Fault. A break in the rocks along which there has been movement of one side relative to the other side.

Fault Block. A body of rocks bounded by one or more faults.

Gross Acres or Gross Wells. The total acres or wells, as the case may be, in which we have a working interest.

Lease Operating Expenses. The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million Btu, or British Thermal Units. One British Thermal Unit is the quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Net Acres or Net Wells. Gross acres or wells multiplied, in each case, by the percentage working interest we own.

Net Production. Production that we own less royalties and production due others.

Oil. Crude oil, condensate or other liquid hydrocarbons.

Operator. The individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

Pay. The vertical thickness of an oil and gas producing zone. Pay can be measured as either gross pay, including non-productive zones or net pay, including only zones that appear to be productive based upon logs and test data.

PV10. The pre-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs 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 and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Proved Developed Reserves. Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

Proved Reserves. The estimated quantities of crude oil, natural gas and natural gas liquids, which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Proved Undeveloped Reserves. 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.

Royalty. An interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

Standardized Measure. The after-tax present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with SEC guidelines, net of estimated production and future development costs, using prices and costs 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 and depreciation, depletion and amortization, and discounted using an annual discount rate of 10%.

Trend. A geographical area that has been known to contain certain types of combinations of reservoir rock, sealing rock and trap types containing commercial amounts of hydrocarbons.

Working Interest. An interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

PART IV

Item 15 – Exhibits and Financial Statement Schedules

All schedules are omitted because the required information is not applicable or is not present in amounts sufficient to require submission of the schedule or because the information required is included in the Consolidated Financial Statement and Notes thereto.

(b) Exhibits. The following exhibits are filed or furnished with or incorporated by reference into this report on Form 10-K:

3.1**	Restated Articles of Incorporation (incorporated by reference from Exhibit 4.1 to the Company's Registration Statement on Form S-3, [333-162607] filed October 21, 2009)
3.2**	Restated Bylaws, dated as of April 3, 2014 (incorporated by reference from Exhibit 3.2 to the Company's Report on Form 8-K filed April 7, 2014)
10.1(a)**	Wells Fargo Bank, National Association – Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed August 2, 2010)
10.1(b)**	Wells Fargo Bank, National Association – Second Amendment to Credit Agreement (incorporated by reference from Exhibit 10.1 to the Company's Form 8-K filed July 25, 2013)
10.1(c)**	Wells Fargo Bank, National Association – Mortgage Agreement (incorporated by reference from Exhibit 10.2 to the Company's Form 8-K filed August 2, 2010)
10.1(d)**	Wells Fargo Bank, National Association – Guaranty (incorporated by reference from Exhibit 10.3 to the Company's Form 8-K filed August 2, 2010)
10.2**†	USE 2001 Officers' Stock Compensation Plan (incorporated by reference from Exhibit 4.21 to the Company's Annual Report on Form 10-K filed September 13, 2002)
10.3**†	2001 Incentive Stock Option Plan (amended in 2003) (incorporated by reference from Exhibit 4.2 to the Company's Annual Report on Form 10-K filed April 15, 2005)
10.4**	2008 Stock Option Plan for Independent Directors and Advisory Board Members (incorporated by reference from Exhibit 4.3 to the Company's Annual Report on Form 10-K filed March 13, 2009)
10.5**†	U.S. Energy Corp. Employee Stock Ownership Plan (incorporated by reference from Exhibit 4.1 to the Company's S-8 filed April 13, 2012)
10.6**†	

2012 Equity Plan (incorporated by reference from Appendix A to the Company's Proxy Statement on Form DEF14A filed April 30, 2012)

10.6.1**	Form of Grant to the 2012 Equity Plan (incorporated by reference from Exhibit 10.5.1 to the Form 10-K filed March 18, 2013)
10.7**	Form of Production Payment Royalty Agreement (Exhibit A to the Asset Purchase Agreement with sxr Uranium One, Inc.) (incorporated by reference from Exhibit 10.2 to the Company's Report on Form 8-K filed February 23, 2007)
10.8(a)**†	Executive Employment Agreement – Keith G. Larsen (effective 4-20-12) (incorporated by reference from Exhibit 10.1 to the Form 8-K filed January 17, 2012)
10.8(b)**†	Executive Employment Agreement – Mark J. Larsen (effective 4-20-12) (incorporated by reference from Exhibit 10.2 to the Form 8-K filed January 17, 2012)
10.8(c)**†	Executive Employment Agreement – Steven R. Youngbauer (effective 4-20-12) (incorporated by reference from Exhibit 10.3 to the Form 8-K filed January 17, 2012)
10.8(d)**†	Form of Executive Severance and Non-Compete Agreement (incorporated by reference from Exhibit 10.1 to the Company's Quarterly Report on From 10-Q filed on May 10, 2013)
10.9**	Agreement for Purchase of Leasehold Interests in McKenzie and Williams Counties, North Dakota (Brigham Oil & Gas, L.P.) (incorporated by reference from Exhibit 10.6 to the Company's Annual Report on Form 10-K filed March14, 2012)
10.10(a)**	Agreement for Purchase of Leasehold Interests in McKenzie County, North Dakota (Geo Resources, Inc.) (incorporated by reference from Exhibit 10.7(a) to the Company's Annual Report on Form 10-K filed March14, 2012)
10.10(b)**	Amendments (5) to Agreement for Purchase of Leasehold Interest in McKenzie County, North Dakota (Geo Resources, Inc.) (incorporated by reference from Exhibit 10.7(b) to the Company's Annual Report on Form 10-K filed March14, 2012)
10.11(a)**	Participation Agreement between Energy One, LLC and Contango/Crimson effective February18, 2011 for the Leona River Project (incorporated by reference from Exhibit 10.10(a) to the Company's Annual Report on Form 10-K filed March 12, 2014)
10.11(b)**	Participation Agreement between Energy One, LLC and Contango/Crimson effective April 1, 2011 for the Booth/Tortuga Project (incorporated by reference from Exhibit 10.10(a) to the Company's Annual Report on Form 10-K filed March 12, 2014)
14.0**	Code of Ethics (incorporated by reference from Exhibit 14 to the Company's Annual Report on Form 10-K filed March 30, 2004)
21.1**	Subsidiaries of Registrant (incorporated by reference from Exhibit 21.1 to the Company's Annual Report on Form 10-K filed on March 12, 2014
23.1*	Consent of Cawley, Gillespie & Associates, Inc.
23.3*	Consent of Independent Registered Accounting Firm (Hein & Associates LLP)
31.1*	Certification under Rule 13a-14(a) Keith G. Larsen

31.2*	Certification under Rule 13a-14(a) Steven D. Richmond
32.1*	Certification under Rule 13a-14(b) Keith G. Larsen
32.2*	Certification under Rule 13a-14(b) Steven D. Richmond
99.1*	Reserve Report (Cawley, Gillespie & Associates, Inc.)
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.DEF	XBRL Definition Linkbase Document
101.LAB	XBRL Label Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

* Filed herewith. ** Previously filed.
† Exhibit constitutes a management contract or compensatory plan or agreement.

SIGNATURES

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

U.S. ENERGY CORP. (Registrant)

Date: March 11, 2015 By: /s/ Keith G. Larsen
KEITH G. LARSEN, Chief Executive Officer

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

Date: March 11, 2015 By: /s/ Keith G. Larsen
KEITH G. LARSEN, Director, Chairman and CEO (Principal Executive Officer)

Date: March 11, 2015 By: /s/ Steven D. Richmond
STEVEN D. RICHMOND
Chief Financial Officer (Principal Financial Officer)

Date: March 11, 2015 By: /s/ Bryon G. Mowry
BRYON G. MOWRY
Principal Accounting Officer

Date: March 11, 2015 By: /s/ David A. Veltri
DAVID A. VELTRI, President

Date: March 11, 2015 By: /s/ Mark J. Larsen
MARK J. LARSEN, Director

Date: March 11, 2015 By: /s/ Stephen V. Conrad
STEPHEN V. CONRAD, Director

Date: March 11, 2015 By: s/ Jerry W. Danni
JERRY W. DANNI, Director

Date: March 11, 2015 By: /s/ Leo A. Heath
LEO A. HEATH, Director

Date: March 11, 2015 By: /s/ Thomas R. Bandy
THOMAS R. BANDY, Director

Date: March 11, 2015 By: /s/ James B. Fraser
JAMES B. FRASER, Director