US ENERGY CORP
Form 10-K
March 28, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] **Annual report pursuant to section 13 or 15(d) of the SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year Ended December 31, 2017

[ ] **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 000-6814

U.S. ENERGY CORP.
(Exact Name of Company as Specified in its Charter)

Wyoming	**83-0205516**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
950 S. Cherry St., Suite 1515, Denver, Colorado	**80246**
(Address of principal executive offices)	(Zip Code)

Registrant’s telephone number, including area code:

(303)
993-3200

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of exchange on which registered
Common Stock, $0.01 par value	**NASDAQ Capital Market**

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES [ ] NO [X]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES [ ] NO [X]

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 Company 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 (§ 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 [X] NO [ ]

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

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

Large accelerated filer [ ] Accelerated filer [ ] Non-accelerated filer [ ] Smaller reporting company [X]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). YES [ ] NO [X]

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the Registrant, based upon the closing price of the shares of common stock on the NASDAQ Capital Market as of the last business day of the most recently completed second fiscal quarter, June 30, 2017, was $4,171,464.

The Registrant had 12,440,927 shares of its $0.01 par value common stock outstanding as of March 21, 2018.

Documents incorporated by reference: Certain information required by Items 10, 11, 12, 13, and 14 of Part III is incorporated by reference from portions of the registrant’s definitive proxy statement relating to its 2018 annual meeting of stockholders to be filed within 120 days after December 31, 2017.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this Annual Report includes “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933 (the “Securities Act”) and Section 21E of the Securities Exchange Act of 1934 (the “Exchange Act”). All statements other than statements of historical facts are forward-looking statements.

Examples of forward-looking statements in this Annual Report include:

- planned capital expenditures for oil and gas exploration and environmental compliance;
- potential drilling locations and available spacing units, and possible changes in spacing rules;
- cash expected to be available for capital expenditures and to satisfy other obligations;
- recovered volumes and values of oil and gas approximating third-party estimates;
- anticipated changes in oil and gas production;
- drilling and completion activities and opportunities in the Buda, Eagle Ford and other formations in South Texas, the Williston Basin in North Dakota and other areas;
- timing of drilling additional wells and performing other exploration and development projects;
- expected spacing and the number of wells to be drilled with our oil and gas industry partners;
- when payout-based milestones or similar thresholds will be reached for the purposes of our agreements with, Zavanna and other partners;
- expected working and net revenue interests, and costs of wells, relating to the drilling programs with our partners;
- actual decline rates for producing wells in the Buda, Bakken/Three Forks, Eagle Ford and other formations;
- future cash flows, expenses and borrowings;
- pursuit of potential acquisition opportunities;
- our expected financial position;
- our expected future overhead reductions;
- our ability to become an operator of oil and gas properties;
- our ability to raise additional financing and acquire attractive oil and gas properties; and
- other plans and objectives for future operations.

These forward-looking statements are identified by their use of terms and phrases such as “may,” “expect,” “estimate,” “project,” “plan,” “believe,” “intend,” “achievable,” “anticipate,” “will,” “continue,” “potential,” “should,” “could,” “up to,” ar and phrases. Though we believe that the expectations reflected in these statements are reasonable, they involve certain assumptions, risks and uncertainties. Results could differ materially from those anticipated in these statements as a result of numerous factors, including, among others:

- our ability to obtain sufficient cash flow from operations, borrowing and/or other sources to fully develop our undeveloped acreage positions;
- volatility in oil and gas prices, including further declines in oil prices and/or natural gas prices, which would have a negative impact on operating cash flow and could require further ceiling test write-downs on our oil and gas assets;

- the possibility that the oil and gas industry may be subject to new adverse regulatory or legislative actions (including changes to existing tax rules and regulations and changes in environmental regulation);
- the general risks of exploration and development activities, including the failure to find oil and gas in sufficient commercial quantities to provide a reasonable return on investment;
- future oil and gas production rates, and/or the ultimate recoverability of reserves, falling below estimates;
- the ability to replace oil and gas reserves as they deplete from production;
- environmental risks;
- risks associated with our plan to develop additional operating capabilities, including the potential inability to recruit and retain personnel with the requisite skills and experience and liabilities we could assume or incur as an operator or to acquire operated properties or obtain operatorship of existing properties;
- availability of pipeline capacity and other means of transporting crude oil and gas production, and related midstream infrastructure and services;
- competition in leasing new acreage and for drilling programs with operating companies, resulting in less favorable terms or fewer opportunities being available;
- higher drilling and completion costs related to competition for drilling and completion services and shortages of labor and materials;
- unanticipated weather events resulting in possible delays of drilling and completions and the interruption of anticipated production streams of hydrocarbons, which could impact expenses and revenues; and
- unanticipated down-hole mechanical problems, which could result in higher than expected drilling and completion expenses and/or the loss of the wellbore or a portion thereof.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in Item 1A “Risk Factors” in this Annual Report on Form 10-K. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements made above and elsewhere in this Annual Report on Form 10-K. We do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations, or otherwise.

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.

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. 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, or, in the case of a dry well, the reporting to the appropriate authority that the well has been abandoned. 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 as an oil or gas well.

Exploratory Well. A well drilled to find a new field or a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

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.

Mcfe. One thousand cubic feet of natural gas equivalent. Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1 Bbl of oil, condensate or natural gas liquids.

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.

PV-10. 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%.

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 gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

PART I

Item 1 – Business

Overview

U.S. Energy Corp. ("U.S. Energy", the "Company", "we" or "us"), is a Wyoming corporation organized in 1966. 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 activities are 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 have historically explored for and produced oil and gas through a non-operator business model. As a non-operator, we rely on our operating partners to propose, permit, drill, complete and produce oil and gas wells. Before a well is drilled, the operator provides all oil and gas interest owners in the designated well the opportunity to participate in the drilling and completion costs and revenues of the well on a pro-rata basis. Our operating partners also produce, transport, market and account for all oil and gas production. We are currently developing our capability to operate properties.

We believe that additional value can be generated if we have the ability to operate oil and gas properties because operatorship will allow us to control drilling and production timing, capital costs and future planning of operations. We plan to look for opportunities to operate our own wells in the near future through acquisition of new oil and gas properties and/or by consolidating ownership in and around the areas in which we currently participate. We believe the current price climate will make opportunities available for us to acquire and/or develop operated properties, and our objective is to eventually operate the properties which comprise the majority of our production.

Office Location and Website

Our principal executive office is located at 950 S. Cherry Street, Suite 1515, Denver, Colorado 80246, telephone (303) 993-3200.

Our website is www.usnrg.com. We make available on this website, through a direct link to the Securities and Exchange Commission's (the "SEC") website at http://www.sec.gov, free of charge, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, proxy statements and Forms 3, 4 and 5 relating to stock ownership of our directors, executive officers and significant shareholders. You may also find information related to our corporate governance, board committees and code of ethics on our website. Our website and the information contained on or connected to our website are not incorporated by reference herein and should not be considered part of this document. In addition, you may read and copy any materials we file with the SEC at the SEC's Public Reference Room, which is located at 100 F Street, NE, Room 1580, Washington, D.C. 20549. Information regarding the Public Reference Room may be obtained by calling the SEC at (800) 732-0330.

Oil and Gas Operations

We currently participate in oil and gas projects as a non-operating working interest owner through exploration and development agreements with various oil and gas exploration and production companies. Our working interest varies by project and may change over time based on the terms of our leases and operating agreements. These projects may result in numerous wells being drilled over the next three to five years depending on, among other things, commodity prices and the availability of capital resources required to fund the expenditures. We are also actively pursuing potential acquisitions of exploration, development and production-stage oil and gas properties or companies. Key attributes of our oil and gas properties include the following:

Estimated proved reserves of 824,115 BOE (82% oil and 18% natural gas) as of December 31, 2017, with a standardized measure value of $9.3 million.

As of March 28, 2018, our oil and gas leases covered 89,842 gross and 4,744 net acres.

126 gross (13.89 net) producing wells as of December 31, 2017 and as of March 28, 2018.

511 BOE per day average net production for 2017.

PV-10 (defined in "Glossary of Oil and Gas Terms") is a non-GAAP measure that is widely used in the oil and gas industry and is considered by institutional investors and professional analysts when comparing companies. However, PV-10 data is not an alternative to the standardized measure of discounted future net cash flows, which is calculated under GAAP and includes the effects of income taxes. The following table reconciles the standardized measure of discounted future net cash flows to PV-10 as of December 31, 2017, 2016 and 2015:

	2017	2016	2015
Standardized measure of discounted net cash flows	$9,253	$6,747	$17,768
Plus discounted impact of future income tax expense	-	-	-
PV-10	$9,253	$6,747	$17,768

Additional information about our standardized measure and the changes during each of the last three years is included in Note 16 to our consolidated financial statements included in Item 8 of this report on Form 10-K.

Activities with Operating Partners

The Company owns working interests in a geographically and geologically diverse portfolio of oil-weighted prospects in varying stages of exploration and development. Prospect stages range from prospect origination, including geologic and geophysical mapping, to leasing, exploratory drilling and development. The Company participates in the prospect stages either for its own account or with prospective partners to enlarge its oil and gas lease ownership base.

Each of the operators of our principal prospects has a substantial technical staff. We believe that these arrangements currently allow us to deliver value to our shareholders without having to build the full staff of geologists, engineers and land personnel required to work on diverse projects involving horizontal drilling in North Dakota and South Texas and conventional exploration in our Gulf Coast prospects. However, consistent with industry practice with smaller independent oil and gas companies, we also utilize specialized consultants with local expertise as needed. We anticipate that as we establish an operational center in an area, we will hire appropriate resources to supply critical aspects of the operations, such as drilling, completions and production.

Presented below is a description of significant oil and gas projects with our key operating partners which constitute the majority of our production and reserves. In addition to the below descriptions, the Company holds interests in non-operated wells with several operators which constitute the remainder of our PV-10.

Williston Basin, North Dakota (Bakken and Three Forks Formations)

Zavanna, LLC. We have an interest in multiple wells with Zavanna with a working interest of approximately 8.75% and net revenue interests ranging from 6.7% to 7.0%. These properties operated by Zavanna currently comprise approximately 59% of the PV-10 related to our oil and gas reserves.

Texas and Louisiana (Gulf Coast)

Contango Oil and Gas Company (Eagle Ford Shale). We have an interest in multiple wells with Contango who is the operator of the Leona River and Booth Tortuga prospects in which we currently hold a 30% working interest and 22.5% net revenue interest. All of the leases are currently held by production and comprise approximately 8% of the PV-10 related to our oil and gas reserves.

PetroQuest Energy, Inc. We have an interest in three natural gas and oil producing wells with PetroQuest Energy, Inc. ("PetroQuest") in Coastal Louisiana, with working interests of 11.9% (8.3% net revenue interest), 50.0% (36.0% net revenue interest) and 17.0% (12.75% net revenue interest). Petro-Quest operates the wells and they are all held by production. These properties operated by PetroQuest currently comprise approximately 7% of the PV-10 related to our oil and gas reserves.

Environmental Laws and Regulations

For additional information regarding applicable environmental laws and regulations, see *Oil and gas operations are subject to environmental, legislative and regulatory initiatives that can materially adversely affect the timing and cost of operations and the demand for crude oil, natural gas, and NGLs*; *Hazardous Substances and Waste*; *Air Emissions; Discharges into Waters*; *Health and Safety*; *Endangered Species*; and *Global Warming and Climate Change* in Item 1A Risk Factors in this Form 10-K.

Environmental Matters

Our operations and properties are subject to extensive and changing federal, state and local laws and regulations relating to environmental protection, including the generation, storage, handling, emission, transportation and discharge of materials into the environment, and relating to safety and health. The recent trend in environmental legislation and regulation generally is toward stricter standards, and this trend will likely continue. These laws and regulations may:

- Require the acquisition of a permit or other authorization before construction or drilling commences and for certain other activities;
- Limit or prohibit construction, drilling and other activities on certain lands lying within wilderness and other protected areas; and
- Impose substantial liabilities for pollution resulting from its operations.

The permits required for our operations may be subject to revocation, modification and renewal by issuing authorities. Governmental authorities have the power to enforce their regulations, and violations are subject to fines or injunctions, or both. In the opinion of management, we are in substantial compliance with current applicable environmental laws and regulations and have no material commitments for capital expenditures to comply with existing environmental requirements. Nevertheless, changes in existing environmental laws and regulations or in interpretations thereof could have a significant impact on our company, as well as the oil and natural gas industry in general.

The Comprehensive Environmental, Response, Compensation, and Liability Act (“CERCLA”) and comparable state statutes impose strict, joint and several liabilities on owners and operators of sites and on persons who disposed of or arranged for the disposal of “hazardous substances” found at such sites. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. The Federal Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes govern the disposal of “solid waste” and “hazardous waste” and authorize the imposition of substantial fines and penalties for noncompliance. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products. In addition, although RCRA classifies certain oil field wastes as "non-hazardous," such exploration and production wastes could be reclassified as hazardous wastes thereby making such wastes subject to more stringent handling and disposal requirements. Recent regulation and litigation that has been brought against others in the industry under RCRA concern liability for earthquakes that were allegedly caused by injection of oil field wastes.

The Endangered Species Act ("ESA") seeks to ensure that activities do not jeopardize endangered or threatened animal, fish and plant species, nor destroy or modify the critical habitat of such species. Under ESA, exploration and production operations, as well as actions by federal agencies, may not significantly impair or jeopardize the species or its habitat. ESA provides for criminal penalties for willful violations of ESA. Other statutes that provide protection to animal and plant species and that may apply to our operations include, but are not necessarily limited to, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. Although we believe that our operations are in substantial compliance with such statutes, any change in these statutes or any reclassification of a species as endangered could subject our company (directly or indirectly through our operating partners) to significant expenses to modify our operations or could force discontinuation of certain operations altogether.

We are subject to the federal authority of the U.S. Environmental Protection Agency (the “EPA”) and its promulgated rules specifically as they pertain to the Clean Air Act (the “CAA”). Applicable to our business and operations, the CAA regulates the emissions, discharges and controls of oil and natural gas production and natural gas processing operations. The CAA includes New Source Performance Standards (“NSPS”) for the oil and natural gas source category to address emissions of sulfur dioxide, methane and volatile organic compounds (“VOCs”) from new and modified oil and gas production, processing and transmission sources as well as a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. Further, the CAA regulates the emissions from compressors, dehydrators, storage tanks and other production equipment as well as leak detection for natural gas processing plants. Although we cannot predict the cost to comply with current and future rules and regulations at this point, compliance with applicable rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

On April 17, 2012, the EPA finalized rules proposed on July 28, 2011 that establish new air emission controls under the CCA for oil and natural gas production and natural gas processing operations. Specifically, the EPA’s rule package includes NSPS for the oil and natural gas source category to address emissions of sulfur dioxide and VOCs and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. On August 5, 2013, the EPA issued final updates to its 2012 VOC performance standards for storage tanks. The rules establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules revise leak detection requirements for natural gas processing plants. These rules have required a number of modifications to the operations of our third-party operating partners, including the installation of new equipment to control emissions from compressors.

The current and future rules, regulations and proposals requiring the installation of more sophisticated pollution control equipment could have a material adverse impact on our business, results of operations and financial condition.

The federal Water Pollution Control Act of 1972, or the Clean Water Act (the “CWA”), imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. The CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. Costs may be associated with the treatment of wastewater and/or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release.

The disposal of oil and natural gas wastes into underground injection wells are subject to the federal Safe Drinking Water Act, as amended (“SDWA”), and analogous state laws. The SDWA’s Underground Injection Control Program establishes requirements for permitting, testing, monitoring, recordkeeping and reporting of injection well activities as well as a prohibition against the migration of fluid containing any contaminants into underground sources of drinking water. State programs may have analogous permitting and operational requirements. In response to concerns related to increased seismic activity in the vicinity of injection wells, regulators in some states are considering additional requirements related to seismic safety. For example, the Texas Railroad Commission (“RRC”) adopted new oil and gas permit rules in October 2014 for wells used to dispose of saltwater and other fluids resulting from the production of oil and natural gas in order to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to conduct continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position. In addition, any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, issuance of fines and penalties from governmental agencies, incurrence of expenditures for remediation of the affected resource, and imposition of liability by third parties for property damages and personal injury.

Substantially all of the oil and natural gas production in which we have interests is developed from unconventional sources that require hydraulic fracturing as part of the completion process. Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. Over the years, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has adopted final rules in June 2016 to prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management ("BLM") finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. However, the BLM finalized a rule in December 2017 repealing its March 2015 hydraulic fracturing regulations. The repeal has been challenged in court and the final outcome is uncertain at this time.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has not proposed to take any action in response to the report's findings, and additional regulation of hydraulic fracturing at the federal level appears unlikely at this time.

While Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process, the prospect of additional federal legislation related to hydraulic fracturing appears remote at this time. At the state level, some states, including Louisiana and Texas, where we have interests, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Several states, including North Dakota where many of our properties are located, have also proposed or adopted legislative or regulatory restrictions on hydraulic fracturing. A number of municipalities in other states, including Colorado and Texas, have enacted bans on hydraulic fracturing. New York State's ban on hydraulic fracturing was recently upheld by the Courts. In Colorado, the Colorado Supreme Court has ruled the municipal bans were preempted by state law. We cannot predict whether any other legislation will ever be enacted and if so, what its provisions would be. If additional levels of regulation and permits were required through the adoption of new laws and regulations at the federal or state level, which could lead to delays, increased operating costs and process prohibitions that would materially adversely affect our revenue and results of operations.

Oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, are subject to the National Environmental Policy Act, as amended (“NEPA”). NEPA required federal agencies, including the BLM, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare and Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. Governmental permits or authorizations that are subject to the requirements of NEPA are required for exploration and development projects on federal and Indian lands. This process has the potential to delay, limit or increate the cost of developing oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt projects. Many of the activities of our third-party operating partners are covered under categorical exclusions which results in a shorter NEPA review process, however, the impact of the NEPA review process on our third-party operating partners is uncertain at this time and could lead to delays and increased costs that could materially adversely affect our revenues and results of operations.

Climate Change

The EPA has determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulations include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources of greenhouse gas emissions (“GHG”). The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, including GHG emissions from completions and workovers from hydraulically fractured oil wells. Also, in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect. Future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business.

Currently, federal legislation related to the reduction of greenhouse gas emissions appears unlikely; however, many states have established greenhouse gas cap and trade programs, and others are considering carbon taxes or initiatives that promote the use of alternative fuels and renewable sources of energy. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for the oil and natural gas we produce, which could in turn have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other extreme weather events. Such events could disrupt our operations or result in damage to our assets and have an adverse effect on our financial condition and results of operations.

Our third-party operating partners are required to report their GHG under these rules. Although we cannot predict the cost to comply with current and future rules and regulations at this point, compliance with applicable rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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.

Insurance and Employees

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 was responsible for all costs to operate the water treatment plant at the Mt. Emmons Project until the disposition of this property in February 2016. During 2017 and 2018, we have continued, and will continue, to maintain $10 million of coverage for environmental impairment liability.

Employees

As of December 31, 2017, we had 3 total and full-time employees and we utilized several consultants on an as needed basis.

Forward Plan

In 2018 and beyond, we intend to seek additional opportunities in the oil and gas sector, including but not limited to further acquisition of assets, participation with current and new industry partners in their exploration and development projects, acquisition of operating companies, and the purchase and exploration of new acreage positions.

Business Strategy

Key elements of our business strategies include:

Deploy our Capital in a Conservative and Strategic Manner and Review Opportunities to Bolster our Liquidity. In the current industry environment, maintaining liquidity is critical. Therefore, we will be highly selective in the projects we evaluate and will review opportunities to bolster our liquidity and financial position through various means.

Evaluate and Pursue Value-Enhancing Transactions. We will continue to monitor the market for strategic alternatives that we believe could enhance shareholder value.

Continue to Develop Operating Capabilities. We will continue to seek transactions where we can gain operational control of any potential development activities. We seek to gain operatorship to retain more control over the timing, selection and processes which will enhance our ability to maximize our return on invested capital.

Extend the Maturity of Existing Debt. In June 2017, the Company extended the maturity of its Credit Facility to July 30, 2019.

Further strengthen our balance sheet and preserve financial flexibility. In December 2017, the Company closed an exchange agreement by and among the Company, the Company’s wholly owned subsidiary Energy One LLC, and APEG Energy II, L.P. pursuant to which, the Company exchanged $4.5 million of the outstanding borrowings under its Credit Facility for 5,819,270 shares of common stock, resulting in an 84% reduction in annual interest payments.

Industry Operating Environment

The oil and natural gas industry is affected by many factors that we generally cannot control. Government regulations, particularly in the areas of taxation, energy, climate change and the environment, can have a significant impact on operations and profitability. Significant factors that will impact oil prices in the current fiscal year and future periods include: political and social developments in the Middle East, demand in Asian and European markets, and the extent to which members of OPEC and other oil exporting nations manage oil supply through export quotas. Additionally, natural gas prices continue to be under pressure due to concerns over excess supply of natural gas due to the high productivity of emerging shale plays in the United States. Natural gas prices are generally determined by North American supply and demand and are also affected by imports and exports of liquefied natural gas. Weather also has a significant impact on demand for natural gas since it is a primary heating source.

While commodity prices have improved throughout 2017, they have remained volatile over the past three years. Lower oil and gas prices not only decrease our revenues, but an extended decline in oil or gas prices may materially and adversely affect our future business, financial position, cash flows, results of operations, liquidity, ability to finance planned capital expenditures and the oil and natural gas reserves that we can economically produce.

Development

We primarily engage in oil and natural gas exploration and production by participating, on a proportionate basis, alongside third-party interests in wells drilled and completed in spacing units that include our acreage. In addition, from time-to-time, we acquire working interests in wells in which we do not hold the underlying leasehold interests from third parties unable or unwilling to participate in well proposals. We typically depend on drilling partners to propose, permit and initiate the drilling of wells. Prior to commencing drilling, our partners are required to provide all owners of oil, natural gas and mineral interests within the designated spacing unit the opportunity to participate in the drilling costs and revenues of the well to the extent of their pro-rata share of such interest within the spacing unit. We assess each drilling opportunity on a case-by-case basis and participate in wells that we expect to meet our return thresholds based upon our estimates of ultimate recoverable oil and natural gas, expected oil and gas prices, expertise of the operator, and completed well cost from each project, as well as other factors. Historically, we have participated pursuant to our working interest in a vast majority of the wells proposed to us. However, the recent significant decline in oil prices has reduced both the number of well proposals we receive and the proportion of well proposals in which we have elected to participate.

Competition

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

Our larger or integrated competitors may be better able to absorb the burden of existing and future federal, state, and local laws and regulations than we can, which would adversely affect our competitive position. Our ability to discover reserves and acquire additional properties in the future will be dependent upon our ability and resources to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. In addition, we may be at a disadvantage in producing oil and natural gas properties and bidding for exploratory prospects because we have fewer financial and human resources than other companies in our industry. Should a larger and better financed company decide to directly compete with us, and be successful in its efforts, our business could be adversely affected.

Marketing and Customers

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

Our oil production is expected to be sold at prices tied to the spot oil markets. Our natural gas production is expected to be sold under short-term contracts and priced based on first of the month index prices or on daily spot market prices. We rely on our operating partners to market and sell our production. Our operating partners include a concentrated list of exploration and production companies, from large publicly-traded companies to small, privately-owned companies.

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt the drilling and producing activities of our operating partners and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt the operations of our operating partners and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operating partners' operations.

Governmental Regulation

Our operations are subject to various rules, regulations and limitations impacting the oil and natural gas exploration and production industry as whole.

Regulation of Oil and Natural Gas Production

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated by federal, state, tribal and local authorities and agencies. For example, North Dakota require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration and production of oil and natural gas. Many states may also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the process of drilling, completion and abandonment, the establishment of maximum rates of production from wells, and the regulation of spacing, plugging and abandonment of such wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill. Moreover, many states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions. Failure to comply with any such rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry will most likely increase our cost of doing business and may affect our profitability. Because such rules and regulations are frequently amended or reinterpreted, we are unable to predict the future cost or impact of complying with such laws. Significant expenditures may be required to comply with governmental laws and regulations and may have a material adverse effect on our financial condition and results of operations. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. On December 17, 2015, the FERC established a new price index for the five-year period which commenced on July 1, 2016.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future.

Onshore gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case-by-case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Mining Activities

As discussed in Note 6 to the audited financial statements included in Item 8 of this report on Form 10-K and *Management's Discussion and Analysis of Financial Condition and Results of Operations* included in Item 7 of this report on Form 10-K, in February 2016 we disposed of our Mt. Emmons Project located near Crested Butte, Colorado rather than continuing our long-term development strategy. Accordingly, our mining assets and operations are presented as discontinued operations for the year ended December 31, 2016.

Item 1A - Risk Factors

The following risk factors should be carefully considered in evaluating the information in this Annual Report.

Risks Involving Our Business

The development of oil and gas properties involves substantial risks that may result in a total loss of investment.

The business of exploring for and developing natural gas and oil properties involves a high degree of business and financial risk, and thus a significant risk of loss of initial investment that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The cost and timing of drilling, completing and operating wells is often uncertain. Factors which can delay or prevent drilling or production, or otherwise impact expected results, include but are not limited to:

- unexpected drilling conditions;
- inability to obtain required permits from governmental authorities;
- inability to obtain, or limitations on, easements from land owners;
- uncertainty regarding our operating partners' drilling schedules;
- high pressure or irregularities in geologic formations;
- equipment failures;
- title problems;
- fires, explosions, blowouts, cratering, pollution, spills and other environmental risks or accidents;
- changes in government regulations and issuance of local drilling restrictions or moratoria;
- adverse weather;
- reductions in commodity prices;
- pipeline ruptures; and
- unavailability or high cost of equipment, field services and labor.

A productive well may become uneconomic in the event 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. We do not currently operate any of our properties, and therefore 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 has been and may continue to be impacted by adverse commodity prices.

For the three years ended December 31, 2017, oil prices have ranged from highs over $60 per barrel in mid-2017 to lows below $30 per barrel in 2016. Global markets, in reaction to general economic conditions and perceived impacts of future global supply, have caused large fluctuations in price, and we believe significant future price swings are likely. Natural gas prices and NGL prices have experienced volatility of comparable magnitude over the same time period. Volatility in the prices we receive for our oil and gas production have and may continue to 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 gas properties, all of which depend primarily or in part upon those prices. 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 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 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, 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.

The Williston Basin (Bakken and Three Forks Shales) oil price differential could have adverse impacts on our revenue.

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). During 2017, our realized oil prices in the Williston Basin were approximately $6.78 per barrel less than West Texas Intermediate (“WTI”) quoted prices for crude oil. 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 and to affect 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.

The agreement governing our debt contain various covenants that limit our discretion in the operation of our business, could prohibit us from engaging in transactions we believe to be beneficial, and could lead to the accelerated repayment of our debt.

The debt agreement between our wholly-owned subsidiary, Energy One LLC (“Energy One”), and APEG Energy II, L.P. contains restrictive covenants that limit Energy One’s ability to engage in activities that may be in our long-term best interests. Our ability to borrow under the Credit Facility is subject to compliance with certain financial covenants, including covenants that require the (i) PDP Coverage Ratio shall not be less than 1.2 to 1.0; and (ii) the Current Ratio to exceed 1.0 to 1.0, each as defined in the Credit Facility. As of December 31, 2017, Energy One was in compliance with all financial covenants.

Additionally, the Credit Facility restricts Energy One’s ability to incur additional debt, pay cash dividends and other restricted payments, sell assets, enter into transactions with affiliates, and to merge or consolidate with another company. These restrictions on our ability to operate our business could seriously harm our business by, among other things, limiting our ability to take advantage of financings, mergers and acquisitions, and other corporate opportunities.

Our industry partners may elect to engage in drilling activities that we are unwilling or unable to participate in during 2018. 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 additional debt financing, sales of one or more producing or non-producing oil and gas assets and the issuance of shares of our common stock.

The oil and gas business holds the opportunity for significant returns on investment, but achievement of such returns is subject to high risk. For example, 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. 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.

Our ability to use net operating loss carryforwards and realized built in losses to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

In general, under Section 382 of the Internal Revenue Code of 1986, as amended, a corporation that undergoes an "ownership change" is subject to limitations on its ability to utilize its pre-change net operating losses ("NOLs") and realized built in losses ("RBILS") offset future taxable income. In general, an ownership change occurs if the aggregate stock ownership of certain stockholders (generally 5% stockholders, applying certain look-through rules) increases by more than 50 percentage points over such stockholders' lowest percentage ownership during the testing period (generally three years).

On December 27, 2017, the Company paid down debt with common stock. This represented a 49.3% ownership change in the company. As a result, the Company's Net Operating Loss carryforwards will likely be significantly reduced in 2018.

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

The oil and 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 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 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 fracture stimulation 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.

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.

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 gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and gas production depends on a number of factors, including the demand for and supply of oil and 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.

If we are unable to replace reserves, we will not be able to sustain production.

Our future operations depend on our ability to find, develop, or acquire crude oil, natural gas, and NGL reserves that are economically producible. Our properties produce crude oil, natural gas, and NGLs at a declining rate over time. In order to maintain current production rates, we must locate and develop or acquire new crude oil, natural gas, and NGL reserves to replace those being depleted by production. Without successful drilling or acquisition activities, our reserves and production will decline over time. In addition, competition for crude oil and gas properties is intense, and many of our competitors have financial, technical, human, and other resources necessary to evaluate and integrate acquisitions that are substantially greater than those available to us.

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. In the event we do complete an acquisition, its successful impact on our business will depend on a number of factors, many of which are beyond our control. These factors include the purchase price for the acquisition, future crude oil, natural gas, and NGL prices, the ability to reasonably estimate or assess the recoverable volumes of reserves, rates of future production and future net revenues attainable from reserves, future operating and capital costs, results of future exploration, exploitation, and development activities on the acquired properties, and future abandonment and possible future environmental or other liabilities. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves, actual future production rates, and associated costs and potential liabilities with respect to prospective acquisition targets. Actual results may vary substantially from those assumed in the estimates. A customary review of subject properties will not necessarily reveal all existing or potential problems.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties if they have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited. If we are unable to integrate acquisitions successfully and realize anticipated economic, operational and other benefits in a timely manner, substantial costs and delays or other operational, technical or financial problems could result.

Integrating acquired businesses and properties involves a number of special risks. These risks include the possibility that management may be distracted from regular business concerns by the need to integrate operations and systems and that unforeseen difficulties can arise in integrating operations and systems and in retaining and assimilating employees. Any of these or other similar risks could lead to potential adverse short-term or long-term effects on our operating results and may cause us to not be able to realize any or all of the anticipated benefits of the acquisitions.

Lower oil and gas prices may cause us to record ceiling test write-downs.

We use the full cost method of accounting to account for our oil and 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 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 depreciation, depletion and amortization are costs associated with unevaluated properties.

Under the full cost method, net capitalized costs are limited to the lower of (a) unamortized cost reduced by the related net deferred tax liability and asset retirement obligations, and (b) 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.

We perform a quarterly ceiling test for our only oil and gas cost center, which is the United States. During 2017, capitalized costs for oil and gas properties did not exceed the ceiling and therefore we recorded no aggregate ceiling test write-downs. 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, 2017, we used a weighted average price applicable to our properties of $51.34 per barrel for oil and $2.98 per Mcfe for natural gas to compute the future cash flows of each of the producing properties at that date.

Capitalized costs associated with unevaluated properties include exploratory wells in progress, costs for seismic analysis of exploratory drilling locations, and leasehold costs related to unproved properties. Unevaluated properties not subject to depreciation, depletion and amortization amounted to an aggregate of $4.7 million as of December 31, 2017. These costs will be transferred to evaluated properties to the extent that we subsequently determine the properties are impaired or if proved reserves are established.

We do not currently serve as operator for any of our oil and gas properties. Many of our joint operating agreements contain provisions that may be subject to legal interpretation, including allocation of non-consent interests, complex payout calculations that impact the timing of reversionary interests, and the impact of joint interest audits.

Substantially all of our oil and gas interests are subject to joint operating and similar agreements. Some of these agreements include payment provisions that are complex and subject to different interpretations and/or can be erroneously applied in particular situations. In the past, we received significant overpayments due to an operator's failure to timely recognize the payout implications of our joint operating agreements. The operator elected to withhold the net revenues from all of our wells that it operates to recover these overpayments, decreasing cash flows that would otherwise have been available to operate our business.

Joint interest audits are a normal process in our business to ensure that operators adhere to standard industry practices in the billing of costs and expenses related to our oil and gas properties. However, the ultimate resolution of joint interest audits can extend over a long period of time in which we attempt to recover excessive amounts charged by the operator. Joint interest audits result in incremental costs for the audit services and we can incur substantial amounts of legal fees to resolve disputes with the operators of our properties.

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 our industry partners serve as operator 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 commodity prices for a trailing 12-month period and taking into account expected capital, operating 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 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 production costs; ad valorem, severance and excise taxes; availability of capital; estimates of required capital expenditures, 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 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, 2017, all of our estimated proved reserves were producing. 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. Revenue 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 gas reserves. The timing and success of the production and the expenses related to the development of oil and 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 PV-10 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.

Further, the use of a 10% discount factor to calculate PV-10 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 gas industry in general are subject.

The use of derivative 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 is 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 is 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.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), which was passed by the U.S. Congress and signed into law in July 2010, provides for statutory and regulatory requirements for derivative transactions, including crude oil and natural gas derivative transactions. Among other things, the Dodd-Frank Act provides for the creating of position limits for certain derivatives transaction, as well as requiring certain transaction to be cleared on exchanges for which cash collateral will be required. The Dodd-Frank Act requires the Commodities Futures and Trading Commission (the “CFTC”), and the SEC and other regulators to promulgate rules and regulations implementing the Dodd-Frank Act. The CFTC has re-proposed rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on is us uncertain at this time.

It is not possible at this time to predict with certainty the full effect of the Dodd-Frank Act and the CFTC rules on us and the timing of such effects. The Dodd-Frank Act may require us to comply with margin requirements and with certain clearing and trade-execution requirements if we do not satisfy certain specific exceptions. Although we expect to qualify for the end-use exception to the clearing, trade-execution and margin requirement for swaps entered to hedge our commodity risks, the application of the requirements to other market participants, such as swap dealers, may change the cost and availability of our derivatives. Depending on the rules adopted by the CFTC or similar rules that may be adopted by other regulatory bodies, we might in the future be required to provided cash collateral for our commodities derivative transactions under circumstances in which we do not currently post cash collateral. Posting of such additional cash collateral could therefore reduce our ability to execute transactions to reduce commodity price risk and thus protect cash flows.

The full impact of the Dodd-Frank Act and related regulatory requirements on our business will not be known until all of the regulations are implemented. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operation may become more volatile and our cash flows may be less predictable. In addition, the Dodd-Frank Acts was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices.

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, 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 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.

Insurance may be insufficient to cover future liabilities.

Our business is currently focused on oil and gas exploration and development and 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. Since 2011 we have obtained 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 environmental exposures related to our prior ownership of the water treatment plant operations related to our discontinued mining operations. These policies provide coverage for remediation 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 operations are subject to environmental, legislative and regulatory initiatives that can materially adversely affect the timing and cost of operations and the demand for crude oil, natural gas, and NGLs.

Our operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of human health and safety, the environment and natural resources. These laws and regulations can restrict or impact our business activities in many ways including, but not limited to the following:

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- requiring the installation of pollution-control equipment or otherwise restricting the handling or disposal of wastes and other substances associated with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species and/or species of special statewide concern or their habitats;
- requiring investigatory and remedial actions to address pollution caused by our operations or attributable to former operations;
- requiring noise, lighting, visual impact, odor and/or dust mitigation, setbacks, landscaping, fencing, and other measures;
- restricting access to certain equipment or areas to a limited set of employees or contractors who have proper certification or permits to conduct work (e.g., confined space entry and process safety maintenance requirements); and
- restricting or even prohibiting water use based upon availability, impacts or other factors.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial or restoration obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, local restrictions, such as state or local moratoria, city ordinances, zoning laws and traffic regulations, may restrict or prohibit the execution of operational plans. In addition, third parties, such as neighboring landowners, may file claims alleging property damage, nuisance or personal injury arising from our operations or from the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. We monitor developments at the federal, state and local levels to inform our actions pertaining to future regulatory requirements that might be imposed to mitigate the costs of compliance with any such requirements. We also monitor industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned in relation to pollution prevention and incident investigations.

Below is a discussion of the major environmental, health and safety laws and regulations that relate to our business. We believe that we are in material compliance with these laws and regulations. We do not believe that compliance with existing environmental, health and safety laws or regulations will have a material adverse effect on our financial condition, results of operations or cash flow. At this point, however, we cannot reasonably predict what applicable laws, regulations or guidance may eventually be adopted with respect to our operations or the ultimate cost to comply with such requirements.

Hazardous Substances and Waste

The Resource Conservation and Recovery Act ("RCRA") and comparable state statues regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. In the course of our operations, we and others generate petroleum hydrocarbon wastes, produced water and ordinary industrial wastes. While the RCRA currently exempts certain drilling fluids, produced waters, and other wastes associated with exploration, development and production of crude oil and natural gas from regulation as hazardous wastes, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we can provide no assurance that this exemption will be preserved in the future. For example, following the filing of a lawsuit by several non-governmental environmental groups against the EPA for the agency's failure to timely assess its RCRA Subtitle D criteria regulation for oil and gas wastes, EPA and the environmental groups entered into an agreement that was finalized in a consent decree issued by the U.S. District Court for the District of Columbia in December 2016. Under the decree, the EPA is required to propose no later than March 15, 2019, a rulemaking for revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is not necessary. If EPA proposes a rulemaking for revised oil and gas waste regulation, the Consent Decree requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose and would cause us, as well as our competitors, to incur significantly increased operating expenses.

Federal, state and local laws may also require us to remove or remediate wastes or hazardous substances that have been previously disposed or released into the environment. This can include removing or remediating wastes or hazardous substances disposed or released by us (or prior owners or operators) in accordance with then current laws, suspending or ceasing operations at contaminated areas, or performing remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA") and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered legally responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, persons who disposed or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to the site. CERCLA and analogous state laws also authorize the EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and/or seek recovery of the costs of such actions from responsible classes of persons.

The Underground Injection Control ("UIC") Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. Permits for Class II UIC wells may be issued by the EPA or by a state regulatory agency if EPA has delegated its UIC Program authority. Because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal.

Air Emissions

We are subject to the federal Clean Air Act (the "CAA") and comparable state laws and regulations. Among other things, these laws and regulations regulate emissions of air pollutants from various industrial sources, including compressor stations and production equipment, and impose various control, monitoring and reporting requirements. Permits and related compliance obligations under the CAA, each state's development and promulgation of regulatory programs to comport with federal requirements, as well as changes to state implementation plans for controlling air emissions in regional non-attainment or near-non-attainment areas, may require oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

The CAA and comparable state laws regulate emissions of various air pollutants through air emissions, permitting programs and other requirements. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions at specified sources. For example, under the EPA's New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAP") regulations, since January 1, 2015, owners and operators of hydraulically fractured natural gas wells (wells drilled principally for the production of natural gas) have been required to use so-called "green completion" technology to recover natural gas that formerly would have been flared or vented. In 2016, the EPA issued additional rules for the oil and gas industry to reduce emissions of methane, VOCs and other compounds. These rules apply to certain sources of air emissions that were constructed, reconstructed, or modified after September 18, 2015. Among other things, the new rules impose green completion requirements on new hydraulically fractured or re-fractured oil wells and leak detection and repair requirements at well sites. We do not expect that the currently applicable NSPS or NESHAP requirements will have a material adverse effect on our business, financial condition or results of operations. However, any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permitting requirements or use specific equipment or technologies to control emissions.

On December 17, 2014, the EPA proposed to revise and lower the existing 75 ppb National Ambient Air Quality Standard (“NAAQS”) for ozone under the federal Clean Air Act to a range within 65-70 ppb. On October 1, 2015, EPA finalized a rule that lowered the standard to 70 ppb. This lowered ozone NAAQS could result in an expansion of ozone nonattainment areas across the United States, including areas in which we operate. Oil and gas operations in ozone nonattainment areas likely would be subject to more stringent emission controls, emission offset requirements for new sources, and increased permitting delays and costs. This could require a number of modifications to our operations, including the installation of new equipment to control emissions from our wells. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

Discharges into Waters

The federal Water Pollution Control Act, or the Clean Water Act (the “CWA”), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. Spill prevention, control and countermeasure regulations require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and construction activities.

The Oil Pollution Act of 1990 (the “OPA”) establishes strict liability for owners and operators of facilities that release oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A ‘‘responsible party’’ under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the United States.

Health and Safety

The Occupational Safety and Health Act (“OSHA”) and comparable state laws regulate the protection of the health and safety of employees. The federal Occupational Safety and Health Administration has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. OSHA also requires employee training and maintenance of records, and the OSHA hazard communication standard and EPA community right-to-know regulations under the Emergency Planning and Community Right-to-Know Act of 1986 require that we organize and/or disclose information about hazardous materials used or produced in our operations.

Endangered Species

The Endangered Species Act (the “ESA”) prohibits the taking of endangered or threatened species or their habitats. While some of our assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, we believe that we are in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where we intend to operate could materially limit or delay our plans.

Global Warming and Climate Change

Certain scientific studies have found that emissions of carbon dioxide, methane and other "greenhouse gases" are contributing to warming of the Earth's atmosphere and other climatic changes. Based on these findings, the EPA determined that greenhouse gases present an endangerment to public health and the environment and has issued regulations to restrict emissions of greenhouse gases under existing provisions of the CAA. These regulation include limits on tailpipe emissions from motor vehicles and preconstruction and operating permit requirements for certain large stationary sources. The EPA has also adopted rules requiring the reporting of greenhouse gas emissions from a variety of sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis, including greenhouse gas emission from collection and workover from hydraulically fractured oil wells. The revisions also include the addition of well identification reporting requirements for certain facilities. Also in June 2016, the EPA finalized rules that establish new air emission controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production, processing, transmission, and storage activities. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards. The EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect. Future implementation of the 2016 standards is uncertain at this time. In another example, the BLM published a final rule in November 2016 that imposes requirements to reduce methane emissions from venting, flaring, and leaking on federal and Indian lands. However, in December 2017, the BLM published a final rule that temporarily suspends or delays certain requirements contained in the November 2016 final rule until January 17, 2019. The Suspension of the November 2016 final rule is being challenged in court. These rules, should they remain in effect, or any other new methane emission standards imposed on the oil and gas sector, could result in increased costs to our operations as well as result in delays or curtailment in such operations, which costs, delays or curtailment could adversely affect our business. The potential increase in operating costs could include new or increased costs to (i) obtain permits, (ii) operate and maintain our equipment and facilities, (iii) install new emission controls on equipment and facilities, (iv) acquire allowances authorizing greenhouse gas emissions, (v) pay taxes related to greenhouse gas emissions and (vi) administer and manage a greenhouse gas emissions program. In addition to these federal actions, various state governments and/or regional agencies may consider enacting new legislation and/or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources.

Currently, federal legislation related to the reduction of greenhouse gas emissions appears unlikely; however, many state have established greenhouse gas cap and trade programs, and others are considering carbon taxes or initiatives that promote the use of alternative fuels and renewable sources of energy. The adoption of legislation or regulatory programs to reduce emissions of greenhouse gases could require us to incur increased operating costs. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce, which in turn could have the effect of lowering the value of our reserves. Consequently, legislation and regulatory programs to reduce emissions of greenhouse gases could have an adverse effect on our business, financial condition and results of operations. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oi and natural gas activities. Ultimately this could make it more difficult to secure funding for exploration and production or midstream activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and natural gas will continue to represent a substantial percentage of global energy use over that time. It should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other extreme weather events. Such weather events could disrupt our operations or result in damages to our assets and have an adverse effect on our financial condition and results of operations.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and "represent a progression" in their nationally determined contributions, which set emissions reduction goals, every five years. The Paris Agreement, which went into effect in November 2016, could further drive regulation in the United States. However, in June 2017, the United States announced its withdrawal from the Paris Agreement, although the earliest possible effective date of withdrawal is November 2020. Despite the planned withdrawal, certain U.S. city and state governments have announced their intention to satisfy their proportionate obligations under the Paris Agreement. The United States' adherence to the exit process is uncertain and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Restrictions on emissions of methane or carbon dioxide that have been or may be imposed in various states, or at the federal level could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Over the years, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, and proposals have been made to enact separate federal, state and local legislation that would increase the regulatory burden imposed on hydraulic fracturing. For example, the EPA has taken the following actions and issued: guidance under the SDWA for hydraulic fracturing activities involving the use of diesel fuel; final regulations under the federal

CAA governing performance standards, including standards for the capture of volatile organic compounds and methane emissions released during hydraulic fracturing and finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. However, the BLM finalized a rule in December 2017 repealing its March 2015 hydraulic fracturing regulations. The repeal has been challenged in court and the final outcome is uncertain at this time.

In December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources under some circumstances, noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. The EPA has not proposed to take any action in response to the report's findings and additional federal regulation of hydraulic fracturing appears unlikely at this time.

While Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process, the prospect of additional federal legislation related to hydraulic fracturing appears remote at this time. At the state level, some states, including Louisiana and Texas, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. There has also been increased public scrutiny of seismic events in areas where hydraulic fracturing of wastewater disposal activities occur. Moreover, some states and local governments have enacted laws or regulations limiting hydraulic fracturing within their borders or prohibiting the activity altogether. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

The state of Texas has adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, waste disposal, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of drilling in general and/or hydraulic fracturing in particular. Recently, several municipalities have passed or proposed zoning ordinances that ban or strictly regulate hydraulic fracturing within city boundaries, setting the stage for challenges by state regulators and third-parties. Similar events and processes are playing out in several cities, counties, and townships across the United States. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct, operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and could even be prohibited from drilling and/or completing certain wells.

The EPA also has initiated a stakeholder and potential rulemaking process under the Toxic Substances Control Act ("TSCA") to obtain data on chemical substances and mixtures used in hydraulic fracturing. The EPA has not indicated when it intends to issue a proposed rule, but it issued an Advanced Notice of Proposed Rulemaking in May 2014, seeking public comment on a variety of issues related to the TSCA rulemaking.

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Requirements to reduce gas flaring could have an adverse effect on our operations.

Wells in the Bakken and Three Forks formations in North Dakota, where we have significant operations, produce natural gas as well as crude oil. Constraints in the current gas gathering and processing network in certain areas have resulted in some of that natural gas being flared instead of gathered, processed and sold. In June 2014, the North Dakota Industrial Commission, North Dakota's chief energy regulator, adopted a policy to reduce the volume of natural gas flared from oil wells in the Bakken and Three Forks formations. 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.

Permitting

In addition, oil and gas 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.

Our ability to produce crude oil, natural gas, and associated liquids economically and in commercial quantities could be impaired if we are unable to acquire adequate supplies of water for our drilling operations and/or completions or are unable to dispose of or recycle the water we use at a reasonable cost and in accordance with applicable environmental rules.

The hydraulic fracturing process on which we and others in our industry depend to complete wells that will produce commercial quantities of crude oil, natural gas, and NGLs requires the use and disposal of significant quantities of water. Our inability to secure sufficient amounts of water, or to dispose of, or recycle the water used in our operations, could adversely impact our operations. Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of wastes, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of crude oil, natural gas, and NGLs.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions, or termination of our operations, the extent of which cannot be predicted, all of which could have an adverse effect on our operations and financial condition.

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

Oil and 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 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 gas industry can fluctuate significantly, often in correlation with oil and 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 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 depend on key personnel.

Our Chief Executive Officer and Chief Financial Officer have experience in dealing with the acquisition and financing of oil and gas properties. We rely extensively on third party consultants for accounting, legal, professional engineering, geophysical and geological advice in oil and gas matters. The loss of key personnel such as our Chief Executive Officer or Chief Financial Officer could adversely impact our business, as finding replacements could be difficult as a result of competition for experienced personnel.

Risks Related to Our Stock

We have issued shares of Series A Preferred Stock with rights superior to those of our common stock.

Our articles of incorporation authorize the issuance of up to 100,000 shares of preferred stock, $0.01 par value. Shares of preferred stock may be issued with such dividend, liquidation, voting and conversion features as may be determined by the Board of Directors without shareholder approval. Pursuant to this authority, in February 2016 we approved the designation of 50,000 shares of Series A Convertible Preferred Stock ("Series A Preferred") in connection with the disposition of our mining segment.

The Series A Preferred accrues dividends at a rate of 12.25% per annum of the Adjusted Liquidation Preference; such dividends are not payable in cash but are accrued and compounded quarterly in arrears. The "Adjusted Liquidation Preference" is initially $40 per share of Series A Preferred for an aggregate of $2.0 million, with increases each quarter by the accrued quarterly dividend. The Series A Preferred is senior to other classes or series of shares of the Company with respect to dividend rights and rights upon liquidation. No dividend or distribution will be declared or paid on our common stock, (i) unless approved by the holders of Series A Preferred and (ii) unless and until a like dividend has been declared and paid on the Series A Preferred on an as-converted basis.

At the option of the holder, each share of Series A Preferred may initially be converted into 13.33 shares of our common stock (the "Conversion Rate") for an aggregate of 666,667 shares. The Conversion Rate is subject to anti-dilution adjustments for stock splits, stock dividends and certain reorganization events and to price-based anti-dilution protections. Each share of Series A Preferred will be convertible into a number of shares of common stock equal to the ratio of the initial conversion value to the conversion value as adjusted for accumulated dividends multiplied by the Conversion Rate. In no event will the aggregate number of shares of common stock issued upon conversion be greater than 793,000 shares. The Series A Preferred will generally not vote with our common stock on an as-converted basis on matters put before our shareholders. The holders of the Series A Preferred have the right to require us to repurchase the Series A Preferred in connection with a change of control. The dividend, liquidation and other rights provided to holders of the Series A Preferred will make it more difficult for holders of common stock to realize value from their investment.

One of our existing stockholders beneficially owns a significant portion of our common stock, and its interests may conflict with those of our other shareholders.

As of March 21, 2018, APEG Energy II, L.P. beneficially owned approximately 46.8% of our outstanding common stock, consisting of 5,819,270 shares of our common stock. As a result, APEG Energy II, L.P. is able to exercise significant influence over matters requiring stockholder approval, including the election of directors, the adoption or amendment of provisions in our charter and bylaws, the approval of mergers and other significant corporate transactions. The interests of APEG Energy II, L.P. with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities, may conflict with the interests of our other stockholders.

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

From time to time, we have sold common stock, warrants, convertible preferred stock 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. Vesting of restricted common stock and 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 do not intend to declare dividends on our common stock in the foreseeable future. Under the terms of our Series A Preferred Stock, we are prohibited from paying dividends on our common stock without the approval of the holders of the Series A Preferred Stock. Accordingly, our common shareholders 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, 2017, our common stock has traded as high as $1.63 per share and as low as $0.64 per share. We expect our common stock will continue to be subject to fluctuations as a result of a variety of factors, including factors beyond our control. These factors include:

- price volatility in the oil and gas commodities markets;
- variations in our drilling, recompletion and operating activity;
- relatively small amounts of our common stock trading on any given day;
- additions or departures of key personnel;
- legislative and regulatory changes; and
- changes in the national and global economic outlook.

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

If our common stock is delisted from the NASDAQ Capital Market, its liquidity and value could be reduced.

In order for us to maintain the listing of our shares of common stock on the NASDAQ Capital Market, the common stock must maintain a minimum bid price of $1.00 as set forth in NASDAQ Marketplace Rule 5550(a)(2). If the closing bid price of the common stock is below $1.00 for 30 consecutive trading days, then the closing bid price of the common stock must be $1.00 or more for 10 consecutive trading days during a 180-day grace period to regain compliance with the rule. We cannot guarantee that we will be able to remain in compliance with the minimum price requirement or satisfy other continued listing requirements. If our common stock is delisted from trading on the NASDAQ Capital Market, it may be eligible for trading over the counter, but the delisting of our common stock from NASDAQ could adversely impact the liquidity and value of our common stock.

Item 1 B - Unresolved Staff Comments.

None.

Item 2 – Properties

Oil and 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 independent reserve engineers. Reserve estimates are based on average prices per barrel of oil and per MMbtu of natural gas at the first day of each month of the 12-month period prior to the end of the reporting period. Reserve estimates as of December 31, 2017, 2016 and 2015 are based on the following average prices, in each case as adjusted for transportation, quality, and basis differentials applicable to our properties on a weighted average basis:

	2017	2016	2015
Oil (per Bbl)	$51.34	$42.75	$50.28
Gas (per Mcfe)	$2.98	$2.48	$2.59

Presented below is a summary of our proved oil and gas reserve quantities as of the end of each of our last three fiscal years:

	As of December 31,								
	2017 (1)			**2016** (1)			**2015** (1)		
	Oil (Bbl)	Gas (Mcf)	Total (BOE)	Oil (Bbl)	Gas (Mcf)	Total (BOE)	Oil (Bbl)	Gas (Mcf)	Total (BOE)
Proved developed	676,030	888,507	824,115	657,280	1,379,170	887,142	1,248,750	2,068,190	1,593,448
Proved undeveloped	-	-	-	-	-	-	366,430	409,740	434,720
Total proved reserves	676,030	888,507	824,115	657,280	1,379,170	887,142	1,615,180	2,477,930	2,028,168

(1) Our reserve estimates as of December 31, 2017, 2016 and 2015 are based on reserve reports prepared by Jane E. Trusty, PE. Ms. Trusty is an independent petroleum engineer and a State of Texas Licensed Professional Engineer (License #60812). The reserve estimates provided by Ms. Trusty were based upon her review of the production histories and other geological, economic, ownership and engineering data, as provided by us or as obtained from the operators of our properties. A copy of Ms. Trusty's report is filed as an exhibit to this report on Form 10-K.

As of December 31, 2017, our proved reserves totaled 824,115 BOE, of which 100% were classified as proved developed. On a BOE basis, approximately 82% of the total is derived from 676,030 Bbls of oil and 18% is derived from 888,507 Mcf of natural gas. 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 believe 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 currently maintained by Jane Trusty, PE. Ms. Trusty 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 Ms. Trusty can prepare her independent reserve estimates and final report.

Proved Undeveloped Reserves. As of December 31, 2017 and December 31, 2016, we did not book any proved undeveloped reserves. During 2015 our proved undeveloped reserves were 434,720 BOE as of December 31, 2015. The main driver of the Company not booking any proved undeveloped reserves was primarily due to the continued depression in global commodity prices throughout 2017.

As of December 31, 2017, we do not have any material amounts of proved undeveloped reserves that have remained undeveloped for five years or more from the time such reserves were initially categorized. As a result of the continued depressed oil price environment in 2017, we did not incur any capital expenditures to convert proved undeveloped reserves to producing status and we do not have existing plans to incur capital expenditures for this purpose in 2018.

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 gas for the years ended December 31, 2017, 2016 and 2015.

	2017	2016	2015
Production Volume			
Oil (Bbls)	111,914	132,429	221,650
Natural gas (Mcfe)	448,571	477,351	553,505
BOE	186,676	211,988	313,901
Daily Average Production Volume			
Oil (Bbls per day)	307	363	607
Natural gas (Mcfe per day)	1,229	1,308	1,516
BOE per day	511	581	860
Net prices realized			
Oil per Bbl	$45.16	$35.41	$40.82
Natural gas per Mcfe	3.32	2.29	2.26
Oil and natural gas per BOE	35.06	27.11	32.80
Operating Expenses per BOE			
Production costs	$18.22	$12.87	$23.42
Depletion, depreciation and amortization	3.86	11.93	26.80

We encourage you to read this information in conjunction with the information contained in our financial statements and related notes included in Item 8 of this annual report on Form 10-K.

The following table provides a regional summary of our production for the years ended December 31, 2017, 2016 and 2015:

	2017 Oil (Bbl)	Gas (Mcfe)	Total (BOE)	2016 Oil (Bbl)	Gas (Mcfe)	Total (BOE)	2015 Oil (Bbl)	Gas (Mcfe)	Total (BOE)
Williston Basin (North Dakota)	90,534	128,640	111,974	103,423	149,944	128,774	163,380	151,191	188,579
Eagle Ford / Buda (South Texas)	18,281	130,095	39,964	25,192	136,441	47,932	53,149	232,094	91,831
Austin Chalk (South Texas)	3,099	1,960	3,426	3,633	1,347	3,858	4,860	4,190	5,558
Gulf Coast (Louisiana and Texas)	-	187,876	31,312	180	189,619	31,424	261	166,030	27,933
Total	111,914	448,571	186,676	132,428	477,351	211,988	221,650	553,505	313,901

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Drilling and Other Exploratory and Development Activities. The following table sets forth information with respect to development and exploratory wells in which we own an interest in during the periods ended December 31, 2017, 2016 and 2015.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	0	0	0	0	13.0	0.5
Non-productive	-	-				