PRIMEENERGY CORP
Form 10-K
April 18, 2017
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2016

Or

TRANSITION REPORT PURSUANT TO SECTION 13 or 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Transition Period From __________ to __________.

is Commission File Number 0-7406

PrimeEnergy Corporation

(Exact name of registrant as specified in its charter)

Delaware	**84-0637348**
(state or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
9821 Katy Freeway, Houston, Texas	**77024**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (713) 735-0000

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

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

Common Stock, par value $.10 per share

(Title of Class)

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K 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, smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer	Accelerated Filer

Non-Accelerated Filer	Smaller Reporting Company
	Emerging growth company

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

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

The aggregate market value of the voting stock of the Registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the Registrant s most recently completed second fiscal quarter, was $62,702,983.

The number of shares outstanding of each class of the Registrant s Common Stock as of March 31, 2017 was 2,283,011 shares, Common Stock, $0.10 par value.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Registrant s proxy statement to be furnished to stockholders in connection with its Annual Meeting of Stockholders to be held in June 2017, are incorporated by reference in Part III hereof.

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This Report may contain statements relating to the future results of the Company that are considered forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 (the PSLRA). In addition, certain statements may be contained in the Company s future filings with the SEC, in press releases, and in oral and written statements made by or with the approval of the Company that are not statements of historical fact and constitute forward-looking statements within the meaning of the PSLRA. Such forward-looking statements, in addition to historical information, which involve risk and uncertainties, are based on the beliefs, assumptions and expectations of management of the Company. Words such as expects , believes , should , plans , anticipates , will , potential , intend , may , outlook , predict , project , would , estimates , assumes , likely and variations of such simil intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve risks and uncertainties and are based on a number of assumptions that could ultimately prove inaccurate and, therefore, there can be no assurance that they will prove to be accurate. Actual results and outcomes may vary materially from what is expressed or forecast in such statements due to various risks and uncertainties. These risks and uncertainties include, among other things, the possibility of drilling cost overruns and technical difficulties, volatility of oil and gas prices, competition, risks inherent in the Company s oil and gas operations, the inexact nature of interpretation of seismic and other geological and geophysical data, imprecision of reserve estimates, and the Company s ability to replace and expand oil and gas reserves. Accordingly, stockholders and potential investors are cautioned that certain events or circumstances could cause actual results to differ materially from those projected. The forward looking statements are made as of the date of this Report and other than as required by the federal securities laws, the Company assumes no obligation to update the forward-looking statement or to update the reasons why actual results could differ from those projected in the forward-looking statements.

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PrimeEnergy Corporation

FORM 10-K ANNUAL REPORT

For the Fiscal Year Ended

December 31, 2016

PART I

Item 1. BUSINESS.

General

PrimeEnergy Corporation (the Company) was organized in March, 1973, under the laws of the State of Delaware.

We are an independent oil and natural gas company engaged in acquiring, developing and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, New Mexico, Colorado and Louisiana. All of our oil and gas properties and interests are located in the United States. Through our subsidiaries Prime Operating Company, Eastern Oil Well Service Company and EOWS Midland Company, we act as operator and provide well servicing support operations for many of the onshore oil and gas wells in which we have an interest, as well as for third parties. We have owned and operated properties in the Gulf of Mexico through our subsidiary Prime Offshore L.L.C. We are also active in the acquisition of producing oil and gas properties through joint ventures with industry partners. Our subsidiary, PrimeEnergy Management Corporation (PEMC), acts as the managing general partner of seven oil and gas limited partnerships (the Partnerships), and acts as the managing trustee of two asset and income business trusts (the Trusts).

Exploration, Development and Recent Activities

The Company s activities include development and exploratory drilling. Our strategy is to develop a balanced portfolio of drilling prospects that includes lower risk wells with a high probability of success and higher risk wells with greater economic potential. Based upon the results of horizontal wells drilled by us and other offsetting operators and historical vertical well performance, we decided in 2016 to reduce the number of vertical wells in our drilling program and drill more horizontal wells. We believe horizontal development of our resource base will provide the opportunity to improve returns relative to vertical drilling by accessing a larger base of reserves in target zones with a lateral wellbore.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2017, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2017 capital budget is reflective of decreased commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity we may adjust our capital program throughout the year, divest non-strategic assets, or enter into strategic joint ventures. We are actively in discussions with financial partners for funding to develop our asset base and, if required, pay down our revolving credit facility should our borrowing base become limited due to the deterioration of commodity prices.

In accordance with SEC rules governing the scheduling of the drilling of PUD reserves we have only included in our yearend reserve report, the 18 PUD locations for which we have an Authorization for Expenditure (AFE) and a definitive plan to drill.

Our West Texas horizontal drilling program began in 2015 with the drilling of two wells. Through December 31, 2016 we have drilled and completed eight wells. Development is continuing and we are currently participating in an additional 19 horizontal wells in this program. As of March 31, 2017, these wells are in

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various stages of being drilled, completed, have been placed on production, or are waiting on hydraulic fracture stimulation. We anticipate the drilling of an additional 13 wells in 2017, although AFEs and specific plans for drilling have not been received. Although the actual count may vary, this additional activity brings the anticipated total to 32 horizontal wells drilled in 2017 in our West Texas horizontal drilling program. In addition, the Company is participating for less than 1% interest in 13 other horizontal wells.

In Upton County, Texas, we are developing a contiguous 3,900 acre block with our joint venture partner, Apache Corporation, where the Company holds approximately 48% interest in 2,606 gross acres. Through yearend 2016 six wells had been drilled and completed. In the first quarter of 2017 an additional eight wells have been spud and are in various stages of being drilled or completed. Apache Corporation has indicated their plans to PAD drill the acreage and that future phases of the development will result in approximately 60 horizontal wells being drilled at a cost of about $470 million. We own various interests ranging from 14% to 49% in the lands to be developed in this project and expect our share of these capital expenditures to be approximately $120 million. The actual number of wells to be drilled and the timing of the drilling may vary based on commodity market conditions. Apache drilling plans indicate an additional nine wells will be drilled later this year at a cost of $60 million, of which our share is approximately $19 million. These wells meet the definition of proved undeveloped reserves, however, they were not included in our yearend reserve report because we had not yet received AFEs and formal drilling plans. Also in Upton County, the Company is participating for 4% interest with Apache in the development of a 640 acre block where six wells, that were spud in 2016, have been completed and are on production as of March 31, 2017. These wells were included in our year end reserve report as Proved Undeveloped Reserves.

In 2016 we commenced our Martin County, Texas horizontal drilling program with the drilling of two wells that began production in July, 2016. These wells were drilled on a 960 acre block that the Company is developing with RSP Permian. An additional two wells were spud in the fourth quarter of 2016 and as of March 31, 2017, they are both producing. These two wells were included as PUDs in our yearend reserve report with the Company owning 35% to 38% interest. RSP Permian drilling plans indicate an additional two wells will be drilled in 2017, however, these were not included in the reserves report, as AFEs for these have not yet been received.

The Company maintains an acreage position of 21,166 gross (13,021 net) acres in the Permian Basin in West Texas, primarily in Reagan, Upton, Midland and Martin counties. We believe this acreage has significant resource potential in multiple Spraberry and Wolfcamp intervals that support the potential drilling of as many as 250 additional wells.

Our Oklahoma horizontal development program, which began in 2012, has participated in 24 horizontal wells for approximately $23 million through the first quarter of 2017. Over this same time period the Company chose to retain an over-riding royalty interest in 21 other horizontal wells. Presently the Company is participating with 17.6% interest in a horizontal well in Canadian County operated by Devon Energy and with 11.8% interest in a horizontal well in Kingfisher County operated by Marathon Oil Company. Our share of these two wells will be approximately $2.2 Million. We have also elected to retain an ORRI in two additional horizontal wells currently being drilled in Garfield and Canadian counties. In addition, we are currently participating for 50% interest in a vertical well in Garvin County with an expected cost, net to PrimeEnergy, of $1.3 Million. As of March 31, 2017, five wells have been spud and are either drilling, in the process of being completed and production tested, or are waiting on hydraulic fracture stimulation. The horizontal activity on Company acreage is primarily focused in Canadian, Grady Kingfisher and Garvin counties where we have approximately 2,295 net acres. We believe our acreage has significant additional resource potential that could support the drilling of 78 new horizontal wells based on an estimate of only two wells per section with our share of the capital expenditure being about $42 million at an average 10.5% ownership level.

In 2016, the limited partners of the Company s managed drilling funds, located in West Virginia, voted to terminate the partnerships, sell the wells to the Company and retain their proportionate share of the leases previously held by those partnerships. These leases may potentially see future development should the horizontal shale plays of the Appalachian Basin expand into these areas.

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Significant 2016 Activity

As of December 31, 2016, we had net capitalized costs related to proved oil and gas properties of $187.5 million. Total expenditures for the acquisition, exploration and development of our properties during 2016 were $17.1 million. Proved reserves as of December 31, 2016, were 7.7 MBOE which consisted of 99% proved developed reserves.

During 2016, we participated in drilling a total of 27 gross (3.6 net) wells; all of these wells are currently producing. This included 22 wells in our West Texas drilling program and 4 wells in our Mid-Continent region and one well in our Gulf Coast district.

We believe that our diversified portfolio approach to our drilling activities results in more consistent and predictable economic results than might be experienced with a less diversified or higher risk drilling program profile.

We attempt to assume the position of operator in all acquisitions of producing properties. We will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests and are actively pursuing the acquisition of producing properties. In order to diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets so as to increase our net worth and increase our oil and gas reserve base.

We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, New Mexico, Colorado and Louisiana, and we own a substantial amount of well servicing equipment.

We do not own any refinery or marketing facilities, and do not currently own or lease any bulk storage facilities or pipelines other than adjacent to and used in connection with producing wells and the interests in certain gas gathering systems. All of our oil and gas properties and interests are located in the United States.

In the past, the supply of gas has exceeded demand on a cyclical basis, and we are subject to a combination of shut-in and/or reduced takes of gas production during summer months. Prolonged shut-ins could result in reduced field operating income from properties in which we act as operator.

Exploration for oil and gas requires substantial expenditures particularly in exploratory drilling in undeveloped areas, or wildcat drilling. As is customary in the oil and gas industry, substantially all of our exploration and development activities are conducted through joint drilling and operating agreements with others engaged in the oil and gas business.

Summaries of our oil and gas drilling activities, oil and gas production, and undeveloped leasehold, mineral and royalty interests are set forth under Item 2., Properties, below. Summaries of our oil and gas reserves, future net revenue and present value of future net revenue are also set forth under Item 2., Properties Reserves , below.

Well Operations

Our operations are conducted through our principal offices in Houston, Texas, and district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma, and Charleston, West Virginia. We currently operate 1,513 wells, 311 through the Houston office, 366 through the Midland office, 359 through the Oklahoma City office and 477 through the Charleston, West Virginia office. Substantially all of the wells we operate are wells in which we have an interest.

We operate wells pursuant to operating agreements which govern the relationship between us, as operator, and the other owners of working interests in the properties, including the Partnerships, Trusts and joint venture participants. For each operated well, we receive monthly fees that are competitive in the areas of operations and we also are reimbursed for expenses incurred in connection with well operations.

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The Partnerships, Trusts and Joint Ventures

Since 1975, PEMC has acted as managing general partner of various partnerships, trusts and joint ventures.

PEMC, as managing general partner of the Partnerships and managing trustee of the Trusts, is responsible for all Partnership and Trust activities, the drilling of development wells and the production and sale of oil and gas from productive wells. PEMC also provides administration, accounting and tax preparation for the Partnerships and Trusts from our offices in Houston, Texas. PEMC is liable for all debts and liabilities of the Partnerships and Trusts, to the extent that the assets of a given limited partnership or trust are not sufficient to satisfy its obligations. We stopped sponsoring partnerships and trusts in 1992. In 2016, we liquidated 11 of those partnerships, and today there are only 7 partnerships and 2 trusts remaining. The aggregate number of limited partners in the Partnerships and beneficial owners of the Trusts now administered by PEMC is approximately 660.

Regulation

Regulation of Oil and Natural Gas Exploration and Production:

Exploration and production operations of oil and natural gas are subject to various types of regulations under a wide range of local, state and federal statutes, rules, orders and regulations. These regulations include requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and govern the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells that may be drilled in a given field and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The failure to comply with these rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases the cost of doing business and, consequently, affects profitability. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions affecting operations.

Regulation of Transportation and Sale of Natural Gas:

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended (NGA), the Natural Gas Policy Act of 1978, as amended (NGPA), and regulations promulgated thereunder by the Federal Energy Regulatory Commission (FERC) and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended (the Decontrol Act). Effective January 1, 1993, the Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas and deregulated natural gas prices for all first sales of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC has granted to all producers such as us a blanket certificate of public convenience and necessity authorizing the sale of gas for resale without further FERC approvals. As a result, all of our produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. In addition, under the provisions of the Energy Policy Act of 2005, as amended (the 2005 Act), the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established new regulations that are intended to increase natural gas pricing transparency through, among other things, requiring market participants to report their gas sales transactions annually to the FERC, and new regulations that require certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points on their systems. The 2005 Act also significantly increased the penalties for violations of the NGA and the FERC s regulations. In 2010, the FERC issued Penalty Guidelines for the determination of civil penalties in an effort to add greater fairness, consistency and transparency to its enforcement program.

Our natural gas sales prices continue to be affected by intrastate and interstate gas transportation regulation, because the prices we receive for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace. We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, we cannot predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Further, we cannot predict whether the recent trend toward federal deregulation of the natural gas industry will continue or what effect future policies will have on our sale of gas.

In December 2007, the FERC issued rules (Order No. 704) requiring that any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million British thermal units (MMBtu) during a calendar year must annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase transparency of the wholesale natural gas markets and assist the FERC in monitoring such markets and in detecting market manipulation.

Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to

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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 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 materially different from the effect of such regulation on competitors.

Regulation of Transportation and Sale of Oil:

Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. The price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines, which are regulated by FERC under the Interstate Commerce Act (ICA). FERC requires that pipelines regulated under the ICA file tariffs setting forth the rates and terms and conditions of service, and that such service not be unduly discriminatory or preferential.

Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry In December 2015, to implement this required five-year re-determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 1.23% should be the oil pricing index for the five-year period beginning July 1, 2016. The result of indexing is a ceiling rate for each rate, which is the maximum at which the pipeline may set its interstate transportation rates. A pipeline may also file cost-of-service based rates if rate indexing will be insufficient to allow the pipeline to recover its costs. Rates are subject to challenge by protest when they are filed or changed. For indexed rates, complaints alleging that the rates are unjust and unreasonable may only be pursued if the complainant can show that a substantial change has occurred since the enactment of the Energy Policy Act of 1992 in either the economic circumstances of the pipeline or in the nature of the services provided, that were a basis for the rate. There is no such limitation on complaints alleging that the pipeline s rates or term and conditions of service are unduly discriminatory or preferential.

Another FERC matter that may impact our transportation costs relates to a policy that allows a pipeline structured as a master limited partnership or similar non-corporate entity to include in its rates a tax allowance with respect to income for which there is an actual or potential income tax liability, to be determined on a case by case basis. Generally speaking, where the holder of a partnership unit interest is required to file a tax return that includes partnership income or loss, such unit-holder is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. We currently do not transport any of our oil or natural gas liquids on a pipeline structured as a master limited partnership.

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 the regulation of oil transportation rates will not affect our operations in any way that is materially different from the effect of such regulation on competitors.

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 shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe access to oil pipeline transportation services generally will be available to us to the same extent as to competitors.

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In November 2009, the Federal Trade Commission (the FTC) issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1.0 million per violation per day. In July 2010, the U.S. Congress passed the Dodd-Frank Wall Street Reform and Consumer Protection Act, which incorporated an expansion of the authority of the Commodity Futures Trading Commission (the CFTC) to prohibit market manipulation in the markets regulated by the CFTC. This authority, with respect to oil swaps and futures contracts, is similar to the anti-manipulation authority granted to the FERC with respect to anti-manipulation in the gas industry and the FTC with respect to oil purchases and sales, as described above. In July 2011, the CFTC issued final rules to implement their new anti-manipulation authority. The rules subject violators to a civil penalty of up to the greater of $1.0 million or triple the monetary gain to the person for each violation.

Transportation of Hazardous Materials:

The federal Department of Transportation has adopted regulations requiring that certain entities transporting designated hazardous materials develop plans to address security risks related to the transportation of hazardous materials. The Company does not believe that these requirements will have an adverse effect on the Company or its operations. The Company cannot provide any assurance that the security plans required under these regulations would protect against all security risks and prevent an attack or other incident related to the Company s transportation of hazardous materials.

Environmental Regulations:

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Various federal, state and local laws and regulations governing the protection of the environment, such as the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended (CERCLA), the Federal Oil Pollution Act of 1990, as amended (OPA), the Federal Water Pollution Control Act of 1972, as amended (the Clean Water Act), the Safe Drinking Water Act of 1974, as amended (the Safe Drinking Water Act), and the Federal Clean Air Act, as amended (the Clean Air Act) affect our operations and costs. In particular, exploration, development and production operations, activities in connection with storage and transportation of oil and other hydrocarbons and use of facilities for treating, processing or otherwise handling hydrocarbons and related wastes may be subject to regulation under these and similar state legislation. These laws and regulations:

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with drilling and production activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

- impose substantial liabilities for pollution resulting from operations.

Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties or the imposition of injunctive relief. Changes in environmental laws and regulations occur regularly, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as those in the oil and natural gas industry in general. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production could result in substantial costs and liabilities to us.

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The transition zone and shallow-water areas of the U.S. Gulf Coast are ecologically sensitive. Environmental issues have led to higher drilling costs and a more difficult and lengthy well permitting process. U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, requiring consistency with applicable coastal zone management plans, or otherwise relating to the protection of the environment.

As with the industry generally, compliance with existing regulations increases the overall cost of business. The areas affected include:

- unit production expenses primarily related to the control and limitation of air emissions and the disposal of produced water;

- capital costs to drill exploration and development wells primarily related to the management and disposal of drilling fluids and other oil and natural gas exploration wastes; and

- capital costs to construct, maintain and upgrade equipment and facilities.

Superfund. The CERCLA, also known as the Superfund law, and comparable state laws and regulations imposes liability, without regard to fault or the legality of the original conduct, on certain parties with respect to the release of hazardous substances into the environment. These parties include the current and past owners and operators of a site where the release occurred and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. Under CERCLA, such parties may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the Environmental Protection Agency (EPA), and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substance released into the environment. In the course of ordinary operations, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA s definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

We currently own or lease properties that for many years have been used for the exploration and production of oil and natural gas. Although we and our predecessors have used operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed or released on, under or from the properties currently owned or leased by us or on, under or from other locations where these wastes have been taken for disposal. In addition, many of these properties have been operated by third parties whose actions with respect to the treatment and disposal or release of hydrocarbons or other wastes were not under our control. State and federal laws applicable to oil and gas wastes and properties have become stricter over time. Under these increasingly stringent requirements, these properties and wastes disposed on these properties may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- to remove or remediate previously disposed wastes, including wastes disposed or released by prior owners or operators;

- to clean up contaminated property, including contaminated groundwater; or

- to perform remedial operations to prevent future contamination.

At this time, we do not believe that we are associated with any Superfund site and have not been notified of any claim, liability or damages under CERCLA.

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Oil Pollution Act of 1990. The OPA and regulations thereunder impose liability on responsible parties for damages resulting from oil spills into or upon navigable waters, and adjoining shorelines or in the exclusive economic zone of the United States. Liability under OPA is strict, and under certain circumstances joint and several, and potentially unlimited. A responsible party includes the owner or operator of an onshore facility and the lessee or permittee of the area in which an offshore facility is located. A failure to comply with OPA s requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA and believe that compliance with OPA s operating requirements will not have a material adverse effect on our operations.

U.S. Environmental Protection Agency. The U.S. Environmental Protection Agency regulations address the disposal of oil and natural gas operational wastes under three federal acts more fully discussed in the paragraphs that follow. The Resource Conservation and Recovery Act of 1976, as amended (RCRA), provides a framework for the safe disposal of discarded materials and the management of solid and hazardous wastes. The direct disposal of operational wastes into offshore waters is also limited under the authority of the Clean Water Act. When injected underground, oil and natural gas wastes are regulated by the Underground Injection Control program under the Safe Drinking Water Act. If wastes are classified as hazardous, they must be properly transported, using a uniform hazardous waste manifest, documented, and disposed at an approved hazardous waste facility.

Resource Conservation and Recovery Act. The RCRA is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on a person who is either a generator or transporter of hazardous waste or an owner or operator hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and natural gas exploration and production waste to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. As a result, we are not required to comply with a substantial portion of RCRA s requirements because the operations generate minimal quantities of hazardous wastes. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and natural gas exploration and production wastes from regulation as hazardous waste. Repeal or modification of the exemption by administrative, legislative or judicial process, or modification of similar exemptions in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us to incur increased operating expenses.

Clean Water Act. The Clean Water Act and resulting regulations imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges.

Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for 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. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

Safe Drinking Water Act. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. The Safe Drinking Water

Act establishes a regulatory framework for underground injection, with the main goal being the protection of usable aquifers. The primary objective of injection well operating requirements is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. Hazardous-waste injection well operations are strictly controlled, and certain wastes, absent an exemption, cannot be injected into underground injection control wells. In Louisiana and Texas, no underground injection may take place except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by the permits could subject us to civil and/or criminal enforcement. We believe we are in compliance in all material respects with the requirements of applicable state and federal underground injection control programs and permits.

Hydraulic Fracturing. Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids, usually consisting mostly of water but typically including small amounts of several chemical additives, as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills have been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Greenhouse Gas. In response to studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to global climate change, the United States Congress has considered legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. In addition, many states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The EPA has also begun to regulate carbon dioxide and other greenhouse gas emissions under existing provisions of the Clean Air Act. This includes proposed regulation of methane emissions from the oil and gas sector. If we are unable to recover or pass through a significant portion of our costs related to complying with current and future regulations relating to climate change and GHGs, it could materially affect our operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of, and access to, capital. Future legislation or regulations adopted to address climate change could also make our products more or less desirable than competing sources of energy.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including OCSLA, the National Environmental Policy Act (NEPA), and the Coastal Zone Management Act (CZMA) require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. OCSLA, for instance, requires the U.S. Department of Interior (DOI) to evaluate whether certain proposed activities would cause serious harm or damage to the marine, coastal or human environment. Similarly, NEPA requires DOI and other federal agencies to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency would have to prepare an environmental assessment and, potentially, an environmental impact statement. CZMA, on the other hand, aids states in developing a coastal management program to protect the coastal environment from growing demands associated with various uses, including offshore oil and natural gas development. In obtaining various approvals from the DOI, we must certify that we will conduct our activities in a manner consistent with an applicable program.

Lead-Based Paints. Various pieces of equipment and structures we own may have been coated with lead-based paints as was customary in the industry at the time these pieces of equipment were fabricated and constructed. These paints may contain lead at a concentration high enough to be considered a regulated hazardous waste when removed. If we need to remove such paints in connection with maintenance or other activities and they qualify as a regulated hazardous waste, this would increase the cost of disposal. High lead levels in the paint might also require us to institute certain administrative and/or engineering controls required by the Occupational Safety and Health Act and BSEE to ensure worker safety during paint removal.

Air Pollution Control. The Clean Air Act and state air pollution laws adopted to fulfill its mandates provide a framework for national, state and local efforts to protect air quality. Operations utilize equipment that emit air pollutants subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment. Air emissions associated with offshore activities are projected using a matrix and formula supplied by BSEE, which has primacy from the EPA for regulating such emissions.

Naturally Occurring Radioactive Materials. Naturally Occurring Radioactive Materials (NORM) are materials not covered by the Atomic Energy Act, whose radioactivity is enhanced by technological processing such as mineral extraction or processing through exploration and production conducted by the oil and natural gas industry. NORM wastes are regulated under the RCRA framework, but primary responsibility for NORM regulation has been a state function. Standards have been developed for worker protection, treatment, storage and disposal of NORM waste, management of waste piles, containers and tanks, and limitations upon the release of NORM contaminated land for unrestricted use. We believe that our operations are in material compliance with all applicable NORM standards established by the states, as applicable.

OSHA and Other Laws and Regulations. We are subject to the requirements of the federal Occupational Safety and Health Act (OSHA), and comparable state laws. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state laws require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards related to workplace exposure to hazardous substances and employee health and safety.

Taxation. Our oil and gas operations are affected by federal income tax laws applicable to the petroleum industry. For U.S. income tax reporting purposes, intangible drilling and development costs incurred or borne during the year are permitted to be deducted currently, rather than capitalized. As an independent producer, we are also entitled to a deduction for percentage depletion with respect to the first 1,000 barrels per day of domestic crude oil (and/or equivalent units of domestic natural gas) produced, if such percentage depletion exceeds cost depletion. Generally, this deduction is computed based upon the lesser of 100% of the net income, or 15% of the gross income from a property, without reference to the basis in the property. The amount of the percentage depletion deduction so computed which may be deducted in any given year is limited to 65% of taxable income. Any percentage depletion deduction disallowed due to the 65% of taxable income test may be carried forward indefinitely.

See Notes 1 and 8 to the consolidated financial statements included in this Report for a discussion of accounting for income taxes.

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Competition and Markets

The business of acquiring producing properties and non-producing leases suitable for exploration and development is highly competitive. Our competition, in our efforts to acquire both producing and non-producing properties, include oil and gas companies, independent concerns, income programs and individual producers and operators, many of which have financial resources, staffs and facilities substantially greater than those available to us. Furthermore, domestic producers of oil and gas must not only compete with each other in marketing their output, but must also compete with producers of imported oil and gas and alternative energy sources such as coal, nuclear power and hydroelectric power. Competition among petroleum companies for favorable oil and gas properties and leases can be expected to increase.

The availability of a ready market for any oil and gas produced by us at acceptable prices per unit of production will depend upon numerous factors beyond our control, including the extent of domestic production and importation of oil and gas, the proximity of our producing properties to gas pipelines and the availability and capacity of such pipelines, the marketing of other competitive fuels, fluctuation in demand, governmental regulation of production, refining, transportation and sales, general national and worldwide economic conditions, and use and allocation of oil and gas and their substitute fuels. There is no assurance that we will be able to market all of the oil or gas produced by us or that favorable prices can be obtained for the oil and gas production.

Major Customers

Listed below are the percent of our total oil and gas sales made to each of our customers whose purchases represented more than 10% of our oil and gas sales in 2016.

Oil Purchasers:	
Plains All American Inc.	40.72%
Infinity Hydrocarbons, LLC.	15.18%
Gas Purchasers:	
Targa Pipeline Mid-Continent	34.18%
Continuum Producer Services	11.87%

Although there are no long-term purchasing agreements with these purchasers, we believe that they will continue to purchase our oil and gas products and, if not, could be readily replaced by other purchasers.

Employees

At March 1, 2017, we had 155 full-time employees, 48 of whom were employed at our principal offices in Houston, Texas, at the offices of Prime Operating Company, Eastern Oil Well Service Company and EOWS Midland Company, and 107 employees who were primarily involved in our district operations in Midland, Texas, Elmore City and Oklahoma City, Oklahoma and Charleston, West Virginia.

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Item 1A. RISK FACTORS.

Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were $2.49 per Mmbtu in 2016 compared to $2.59 per Mmbtu in 2015, and have remained flat at $2.51 per Mmbtu in February 2017. Oil prices, based on the NYMEX monthly average price, were $43.29 per barrel in 2016 compared to $50.28 per barrel in 2015, and have increased to $53.16 through February 2017. Any substantial or extended decline in future natural gas or crude oil prices would have, a material adverse effect on our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. Furthermore, substantial, extended decreases in natural gas and crude oil prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow and cost of capital and our ability to access capital markets, increase our costs under our revolving credit facility, and limit our ability to execute aspects of our business plans.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East, Africa and South America;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price levels and quantities of foreign imports;
- actions of governmental authorities;
- the availability, proximity and capacity of gathering, transportation, processing and/or refining facilities in regional or localized areas that may affect the realized price for natural gas and oil;

- inventory storage levels;
- the nature and extent of domestic and foreign governmental regulations and taxation, including environmental and climate change regulation;
- the price, availability and acceptance of alternative fuels;
- technological advances affecting energy consumption;
- speculation by investors in oil and natural gas;
- variations between product prices at sales points and applicable index prices; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas and oil prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

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Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- decreases in natural gas and oil prices;
- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- loss of title or other title related issues;
- surface access restrictions;
- lack of available gathering or processing facilities or delays in the construction thereof;
- compliance with, or changes in, governmental requirements and regulation, including with respect to wastewater disposal, discharge of greenhouse gases and fracturing; and
- shortages or delays in the availability of required goods or services such as drilling rigs or crews, the delivery of equipment and the availability of sufficient water for drilling operations.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate within a particular geographic area may decline. We may be unable to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may be unable to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;

- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board (FASB) in Accounting Standards Codification (ASC) Section 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

The Company s expectations for future drilling activities will be realized over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of such activities.

The Company has identified drilling locations and prospects for future drilling opportunities, including development and infill drilling activities. These drilling locations and prospects represent a significant part of the Company s future drilling plans. The Company s ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, access to and availability of equipment, services, resources and personnel and drilling results. Changes in the laws or regulations on which the Company relies in planning and executing its drilling programs could adversely impact the Company s ability to successfully complete those programs. For example, under current Texas laws and regulations the Company may receive permits to drill, and may drill and complete, certain horizontal wells that traverse one or more units and/or leases; a change in those laws or regulations could adversely impact the Company s ability to drill those wells. Because of these uncertainties, the Company cannot give any assurance as to the timing of these activities or that they will ultimately meet the Company s expectations for success. As such, the Company s actual drilling activities may materially differ from the Company s current expectations, which could have a significant adverse effect on the Company s proved reserves, financial condition and results of operations.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we

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produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

We are continually identifying and evaluating opportunities to acquire natural gas and oil properties. We may not be able to successfully consummate any acquisition, to acquire producing natural gas and oil properties that contain economically recoverable reserves, or to integrate the properties into our operations profitably.

We have substantial capital requirements, and we may not be able to obtain needed financing on satisfactory terms, if at all.

We rely upon access to our revolving credit facility as a source of liquidity for any capital requirements not satisfied by cash flow from operations or other sources. Future challenges in the global financial system, including the capital markets, may adversely affect our business and our financial condition. Our ability to access the capital markets may be restricted at a time when we desire, or need, to raise capital, which could have an impact on our flexibility to react to changing economic and business conditions. Adverse economic and market conditions could adversely affect the collectability of our trade receivables and cause our commodity hedging counterparties to be unable to perform their obligations or to seek bankruptcy protection. Future challenges in the economy could also lead to reduced demand for natural gas which could have a negative impact on our revenues.

Our debt agreements also require compliance with covenants to maintain specified financial ratios. If the price that we receive for our natural gas and oil production further deteriorates from current levels or continues for an extended period, it could lead to further reduced revenues, cash flow and earnings, which in turn could lead to a default under those ratios. Because the calculations of the financial ratios are made as of certain dates, the financial ratios can fluctuate significantly from period to period. A prolonged period of decreased natural gas and oil prices or a further decline could further increase the risk of our inability to comply with covenants to maintain specified financial ratios. In order to provide a margin of comfort with regard to these financial covenants, we may seek to reduce our capital expenditure plan, sell non-strategic assets or opportunistically modify or increase our derivative instruments to the extent permitted under our debt agreements. In addition, we may seek to refinance or restructure all or a portion of our indebtedness. We cannot assure you that we will be able to successfully execute any of these strategies, and such strategies may be unavailable on favorable terms or not at all.

The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could limit us in the future.

The borrowing base under our revolving credit facility is currently $75 million, and lender commitments under our revolving credit facility are $300 million. The borrowing base is redetermined semi-annually under the terms of the revolving credit facility. In addition, either we or the lenders may request an interim redetermination twice a year or in conjunction with certain acquisitions or sales of oil and gas properties. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for other reasons set forth in our revolving credit agreement. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets to meet our obligations, including any such debt repayment obligations.

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Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2017 plan, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover, economic or other circumstances may change from those contemplated by our 2017 plan, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Negative public perception regarding us and/or our industry could have an adverse effect on our operations.

Negative public perception regarding us and/or our industry resulting from, among other things, concerns raised by advocacy groups about hydraulic fracturing, oil spills, greenhouse gas or methane emissions and explosions of natural gas transmission lines, may lead to increased regulatory scrutiny, which may, in turn, lead to new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. These actions may cause operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risk of litigation. Moreover, governmental authorities exercise considerable discretion in the timing and scope of permit issuance and the public may engage in the permitting process, including through intervention in the courts. Negative public perception could cause the permits we need to conduct our operations to be withheld, delayed, or burdened by requirements that restrict our ability to profitably conduct our business.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- uncontrolled flows of natural gas, oil or well fluids;
- formations with abnormal pressures;
- pollution and other environmental risks; and

natural disasters.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance coverage against certain, but not all, hazards that could arise from our operations. Such insurance is believed to be reasonable for the hazards and risks faced by us. We do not carry business interruption insurance. In addition pollution and environmental risks are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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As of December 31, 2016, we maintain for our operations total excess liability insurance with limits of $20 million per occurrence and in the aggregate covering certain general liability and certain sudden and accidental environmental risks with a deductible of $10,000 per occurrence, subject to all terms, restrictions and sub-limits of the policies. We also maintain general liability insurance limits of $1 million per occurrence and $2 million in the aggregate.

We have several policies that cover environmental risks. We have environmental coverage under the per occurrence and aggregate limits of our general and umbrella liability policies (for a twelve-month term). These policies provide third-party surface cleanup, bodily injury and property damage coverage, and defense costs when a pollution event is sudden and accidental and is discovered within thirty days of commencement and reported to the insurance company within ninety days of discovery. This is standard coverage in oil and gas insurance policies.

We seek to protect ourselves from some but not all operating hazards through insurance coverage. However, some risks are either not insurable or insurance is available only at rates that we consider uneconomical. Depending on competitive conditions and other factors, we attempt to obtain contractual protection against uninsured operating risks from our customers and contractors. However, customers and contractors who provide contractual indemnification protection may not in all cases maintain adequate insurance to support their indemnification obligations. Our insurance or indemnification arrangements may not adequately protect us against liability or loss from all the hazards of our operations. The occurrence of a significant event that we have not fully insured or indemnified against or the failure of a customer to meet its indemnification obligations to us could materially and adversely affect our results of operations and financial condition. Furthermore, we may not be able to maintain adequate insurance in the future at rates we consider reasonable.

From time to time, a small number of our contractors have requested contractual provisions that require us to respond to third-party claims. In some of these instances we have accepted the risk with the understanding that it would be covered under our current coverage. We evaluate these risk-transferring negotiations cautiously, and we feel that we have adequately mitigated this risk through existing coverage or acquiring supplemental coverage when appropriate.

Federal and state legislation and regulatory initiatives related to oil and gas development, including hydraulic fracturing, could result in increased costs and operating restrictions or delays.

Most of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids usually consisting mostly of water but typically including small amounts of several chemical additives as well as sand or other proppants into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Most of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act and has released permitting guidance for hydraulic fracturing activities that use diesel in fracturing fluids in those states where EPA is the permitting authority, including Pennsylvania. As a result, we may be subject to additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. In addition, legislation introduced in Congress would provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids. If adopted, this legislation could establish an additional level of regulation and permitting at the federal, state or local levels, and could make it easier for third parties opposed to the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect the environment, including groundwater, soil or surface water. Moreover, in May 2014, the EPA announced an Advanced

Notice

of Proposed Rulemaking under the Toxic Substances Control Act relating to data collection, including the chemical substances and mixtures used in hydraulic fracturing. Further, in March 2015, the Department of the Interior s Bureau of Land Management (BLM) issued a final rule to regulate hydraulic fracturing on public and Indian land; however, enforcement of the rule has been delayed pending a decision in a legal challenge in the U.S. District Court of Wyoming.

On August 16, 2012, the EPA published final rules that establish new air emission control requirements for natural gas and NGL production, processing and transportation activities, including New Source Performance Standards (NSPS) to address emissions of sulfur dioxide and volatile organic compounds, and National Emission Standards for Hazardous Air Pollutants (NESHAPS) to address hazardous air pollutants frequently associated with gas production and processing activities. Among other things, these final rules require the reduction of volatile organic compound emissions from natural gas wells through the use of reduced emission completions or green completions on all hydraulically fractured wells constructed or refractured after January 1, 2015. In addition, gas wells were required to use completion combustion device equipment (i.e., flaring) if emissions cannot be directed to a gathering line. Further, the final rules under NESHAPS include maximum achievable control technology (MACT) standards for small glycol dehydrators that are located at major sources of hazardous air pollutants and modifications to the leak detection standards for valves. In December 2014, the EPA finalized additional amendments to these rules that, among other things, distinguished between multiple flowback stages during completion and clarified that storage tanks permanently removed from service are not affected by any requirements. In July 2015, the EPA finalized two updates to the rules addressing the definition of low pressure gas wells and references to tanks that are connected to one another. In September 2015, the EPA issued a proposed rule that would update and expand the NSPS by setting additional emissions limits for volatile organic compounds and regulating methane emissions for new and modified sources in the oil and gas industry. The EPA also issued a proposed rule in September 2015 concerning aggregation of sources that would affect source determinations for air permitting in the oil and gas industry.

Compliance with these requirements, especially the imposition of these green completion requirements and potential methane regulation, may require modifications to certain of our operations, including the installation of new equipment to control emissions at the well site that could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business. Similarly, aggregating our oil and gas facilities for permitting could result in more complex, costly, and time consuming air permitting. Particularly in regard to obtaining pre-construction permits, the proposed aggregation rule could add costs and cause delays in our operations.

In addition to these federal legislative and regulatory proposals, some states in which we operate, such as West Virginia and Texas, and certain local governments have adopted, and others are considering adopting, regulations that could restrict hydraulic fracturing in certain circumstances, including requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. For example, the City of Denton, Texas adopted a moratorium on hydraulic fracturing in November 2014, though it was later lifted in 2015, and New York issued a statewide ban on hydraulic fracturing in June 2015. In addition, Pennsylvania s Act 13 of 2012 became law on February 14, 2012 and amended the state s Oil and Gas Act to, among other things, increase civil penalties and strengthen the Pennsylvania Department of Environmental Protection s (PaDEP) authority over the issuance of drilling permits. Although the Pennsylvania Supreme Court struck down portions of Act 13 that made statewide rules on oil and gas preempt local zoning rules, this could lead to additional local restrictions on oil and gas activity in the state. Additional challenges to Act 13 are pending before the Pennsylvania Supreme Court; however, the timing of any decision is uncertain.

We use a significant amount of water in our hydraulic fracturing operations. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. 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. For example, in April 2011, PaDEP called on all Marcellus Shale natural gas drilling operators to voluntarily cease by May 19, 2011 delivering wastewater to those centralized treatment facilities that were grandfathered from the application of PaDEP s Total Dissolved Solids regulations. In April 2015, the EPA published proposed pretreatment standards for disposal of wastewater produced from shale gas operations to publicly owned treatment works (POTWs). The regulations will be developed under the EPA s Effluent Guidelines Program under the authority of the Clean Water Act. In response to these actions, operators including us have begun to rely more on recycling of flowback and produced water from well sites as a preferred alternative to disposal.

A number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing practices. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released a draft report in June 2015. It concluded that activities have not led to widespread systematic impacts on drinking water resources in the United States, but there are above and below ground mechanisms by which hydraulic fracturing could affect drinking water resources. This study and other studies that may be undertaken by EPA or other federal agencies could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and natural gas that we produce.

Climate change, the costs that may be associated with its effects, and the regulation of greenhouse gas (GHG) emissions have the potential to affect our business in many ways, including increasing the costs to provide our products and services, reducing the demand for and consumption of our products and services (due to change in both costs and weather patterns), and the economic health of the regions in which we operate, all of which can create financial risks. In addition, legislative and regulatory responses related to GHG emissions and climate change may increase our operating costs. The United States Congress has previously considered legislation related to GHG emissions. There have also been international efforts seeking legally binding reductions in GHG emissions. For example, in November 2014, the Obama Administration announced an agreement with China to voluntarily reduce GHG emissions by 26% to 28% of 2005 levels by 2025. Further, the United States joined over 190 countries in Lima, Peru in December 2014 and agreed to draft an emissions reduction plan ahead of further international climate negotiations in Paris, France in 2015. The United States was actively involved in the negotiations in Paris, which led to the creation of the Paris Agreement. The Paris Agreement will be open for signing on April 22, 2016 and will require countries to review and represent a progression in their intended nationally determined contributions, which set emissions reduction goals, every five years, beginning in 2020. The Paris Agreement sets a goal of keeping warming well below 2 degrees Celsius and sets a target limit of 1.5 degrees Celsius. In addition, increased public awareness and concern may result in more state, regional and/or federal requirements to reduce or mitigate GHG emissions. For example, in June 2013, the Obama Administration announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and gas sector. Pursuant to this plan, the EPA issued a proposed rule updating New Source Performance Standards and setting requirements for methane emissions and volatile organic compounds in the oil and gas sector in September 2015.

In September 2009, the EPA finalized a mandatory GHG reporting rule that requires large sources of GHG emissions to monitor, maintain records on, and annually report their GHG emissions beginning January 1, 2010. The rule applies to large facilities emitting 25,000 metric tons or more of carbon dioxide-equivalent (CO_2e)

emissions per year and to most upstream suppliers of fossil fuels, as well as manufacturers of vehicles and engines. Subsequently, in November 2010, the EPA issued GHG monitoring and reporting regulations that went into effect on December 30, 2010, specifically for oil and natural gas facilities, including onshore and offshore oil and natural gas production facilities that emit 25,000 metric tons or more of CO_2e per year. The rule required reporting of GHG emissions by regulated facilities to the EPA by March 2012 for emissions during 2011 and annually thereafter. We are required to report our GHG emissions to the EPA each year in March under this rule and have submitted our annual reports in compliance with the deadline. The EPA also issued a final rule that makes certain stationary sources and newer modification projects subject to permitting requirements for GHG emissions, beginning in 2011, under the CAA. However, in June 2014, the U.S. Supreme Court, in UARG v. EPA, limited the application of the GHG permitting requirements under the Prevention of Significant Deterioration and Title V permitting programs to sources that would otherwise need permits based on the emission of conventional pollutants.

Federal and state regulatory agencies can impose administrative, civil and/or criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the passage of any federal or state climate change laws or regulations in the future could result in increased costs to (i) operate and maintain our facilities, (ii) install new emission controls on our facilities and (iii) administer and manage any GHG emissions program. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy.

Moreover, some experts believe climate change poses potential physical risks, including an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. In addition, warmer winters as a result of global warming could also decrease demand for natural gas. To the extent that such unfavorable weather conditions are exacerbated by global climate change or otherwise, our operations may be adversely affected to a greater degree than we have previously experienced, including increased delays and costs. However, the uncertain nature of changes in extreme weather events (such as increased frequency, duration, and severity) and the long period of time over which any changes would take place make any estimations of future financial risk to our operations caused by these potential physical risks of climate change unreliable.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator s breach of the applicable agreements or an operator s failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The

U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

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Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. These hedging arrangements limit the benefit to us of increases in prices. While there are many different types of derivatives available, we generally utilize collar and swap agreements to attempt to manage price risk more effectively.

The collar arrangements are put and call options used to establish floor and ceiling prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The swap agreements call for payments to, or receipts from, counterparties based on whether the index price for the period is greater or less than the fixed price established for that period when the swap is put in place. These arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

The CFTC has promulgated regulations to implement statutory requirements for swap transactions. These regulations are intended to implement a regulated market in which most swaps are executed on registered exchanges or swap execution facilities and cleared through central counterparties. While we believe that our use of swap transactions exempt us from certain regulatory requirements, the changes to the swap market due to increased regulation could significantly increase the cost of entering into new swaps or maintaining existing swaps, materially alter the terms of new or existing swap transactions and/or reduce the availability of new or existing swaps. If we reduce our use of swaps as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable.

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The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

The Company s business could be negatively affected by security threats, including cybersecurity threats, and other disruptions.

As an oil and gas producer, the Company faces various security threats, including cybersecurity threats to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the security of the Company s facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. The potential for such security threats has subjected the Company s operations to increased risks that could have a material adverse effect on the Company s business. In particular, the Company s implementation of various procedures and controls to monitor and mitigate security threats and to increase security for the Company s information, facilities and infrastructure may result in increased capital and operating costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of sensitive information, critical infrastructure or capabilities essential to the Company s operations and could have a material adverse effect on the Company s reputation, financial position, results of operations or cash flows. Cybersecurity attacks in particular are becoming more sophisticated and include, but are not limited to, malicious software, attempts to gain unauthorized access to data and systems, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information, and corruption of data. These events could damage the Company s reputation and lead to financial losses from remedial actions, loss of business or potential liability.

Item 1B. UNRESOLVED STAFF COMMENTS.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 2. PROPERTIES.

Our executive offices as well as offices of Prime Operating Company, Eastern Oil Well Service Company, EOWS Midland Company and Prime Offshore L.L.C., are located in leased premises in Houston, Texas.

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We maintain district offices in Midland, Texas, Oklahoma City, Oklahoma and Charleston, West Virginia, and have field offices in Carrizo Springs and Midland, Texas, Elmore City, Oklahoma and Orma, West Virginia.

Substantially all of our oil and gas properties are subject to a mortgage given to collateralize indebtedness or are subject to being mortgaged upon request by our lenders for additional collateral.

The information set forth below concerning our properties, activities, and oil and gas reserves include our interests in affiliated entities.

The following table sets forth the exploratory and development drilling experience with respect to wells in which we participated during the three years ended December 31, 2016.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil						
Gas						
Dry						
Development:						
Oil	27	3.6	8	3.6	25	11.79
Gas						
Dry						
Total:						
Oil	27	3.6	8	3.6	25	11.79
Gas						
Dry						
	27	3.6	8	3.6	25	11.79

Oil and Gas Production

As of December 31, 2016, we had ownership interests in the following numbers of gross and net producing oil and gas wells [(1)].

	Gross	Net
Producing wells[(1)]:		
Oil Wells	853	392
Gas Wells	775	460

(1) A gross well is a well in which a working interest is owned. A net well is the sum of the fractional revenue interests owned in gross wells. Wells are classified by their primary product. Some wells produce both oil and gas.

The following table shows our net production of oil and natural gas for each of the three years ended December 31, 2016. Net production is net after royalty interests of others are deducted and is determined by multiplying the gross production volume of properties in which we have an interest by percentage of the leasehold, mineral or royalty interest owned by us.

	2016	**2015**	**2014**
Oil (barrels)	670,000	720,000	759,000
Gas (Mcf)	4,546,000	4,696,000	4,741,000

The following table sets forth our average sales price per barrel of oil and average sales prices per one thousand cubic feet (Mcf) of gas, together with our average production costs per unit of production for the three years ended December 31, 2016.

	2016	2015	2014
Average sales price per barrel	$ 39.73	$ 70.93	$ 86.68
Average sales price per Mcf	2.57	3.35	5.15
Average production costs per net equivalent barrel(1)	18.21	21.24	25.51

(1) Net equivalent barrels are computed at a rate of 6 Mcf per barrel and costs exclude production taxes.

Average oil and gas prices received excluding the impact of derivatives were:

	2016	2015	2014
Oil Price per barrel	$ 39.78	$ 45.74	$ 86.73
Gas Price per Mcf	2.56	2.71	5.32

Acreage

The following table sets forth the approximate gross and net undeveloped acreage in which we have leasehold and mineral interests as of December 31, 2016. Undeveloped acreage is that acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold acreage	187,579	82,908	3,016	252	190,596	83,159
Mineral fee acreage	1,640	117	19,257	417	20,897	534
Total	189,219	83,025	22,273	669	211,493	83,693

Total Net Undeveloped Acreage Expiration

In the event that production is not established or we take no action to extend or renew the terms of our leases, our net undeveloped acreage that will expire over the next three years, as of December 31, 2016, is 35 acres for the year ending December 31, 2017, none in 2018, and 58 acres in 2019.

Reserves

Our interests, including the interests held by the Partnerships, in proved developed and undeveloped oil and gas properties have been evaluated by Ryder Scott Company, L.P. for each of the three years ended December 31, 2016. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserves estimates can be found in Exhibit 99.1, the Ryder Scott Company, L.P. Report on Registrant s Reserves

Estimates. In matters related to the preparation of our reserve estimates, our district managers report to the Engineering Data manager, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual preparation of reserve estimates of 100% of our year-end reserves by our independent third party engineers, Ryder Scott Company, L.P. The members of our district and central groups consist of degreed engineers, geologists and geophysicists and technicians with between approximately ten and thirty-five years of industry experience, and between three and twenty years of experience managing our reserves. Our Engineering Data manager, the technical person primarily responsible for overseeing the preparation of reserves estimates, has over twenty-five years of experience, holds a Bachelor degree in Geology and an MBA in finance and is a member of the Society of Petroleum Engineers and American Association of Petroleum Geologists. See Part II, Item 8. Financial Statements and Supplementary Data , for additional discussions regarding proved reserves and their related cash flows.

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All of our reserves are located within the continental United States. The following table summarizes our oil and gas reserves at each of the respective dates:

	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
As of December 31,	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe) (a)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe) (a)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe) (a)
2014	6,239	2,160	32,267	13,777	14,709	4,322	26,331	23,420	20,948	6,482	58,958	37,197
2015	4,579	1,673	23,275	10,131	52	12	55	73	4,631	1,685	23,330	10,204
2016	3,107	1,265	13,001	6,539	643	159	2,003	1,135	3,750	1,424	15,004	7,674

(a) In computing total reserves on a barrels of oil equivalent (Boe), gas is converted to oil based on its relative energy content at the rate of six Mcf of gas to one barrel of oil and NGLs are converted based upon volume; one barrel of natural gas liquids equals one barrel of oil.

Proved undeveloped reserves of 23,420 MBoe as of December 31, 2014 included 126 drilling locations in our West Texas drilling program, 10 drilling locations in our Mid-Continent region and 3 drilling locations in our Gulf Coast region. During 2015 we converted 997 MBoe to proved developed producing reserves at a cost of $7.9 million. For our December 31, 2015 reserve report we had removed all but one PUD location, due to the uncertainty of near term commodity prices and available capital for drilling expenditure. This PUD location, part of our West Texas horizontal drilling program, had net proved undeveloped reserves of 73 MBoe, as of December 31, 2015 and was drilled in the first quarter of 2016.

During 2016 five horizontal wells were drilled in West Texas, two in Oklahoma, and one vertical well was drilled onshore Texas Gulf Coast. In addition, we had an increase in reserves from over-riding royalty interest in 14 horizontal wells drilled in Oklahoma by other operators. In total, these projects added 924 MBoe to proved developed producing reserves at a cost of $20.8 million. Included in our December 31, 2016, reserve report are 20 PUD locations, 19 of these being horizontal, and many of these were drilled and cased by yearend, but had not yet been stimulated. Proved undeveloped reserves of 1,135 Mboe are attributable to these 20 wells. As of March 31, 2017, all 20 wells are drilled and cased, seven of these are completed and on production, three are in the process of being hydraulically fracture stimulated and ten are expected to be stimulated within the second quarter of 2017. In addition, the Company is actively participating in ten horizontal wells in West Texas that are in the process of being drilled or completed. The estimated 88ths cost of these ten wells will be approximately $70 Million, of which the Company s share will be about $23 Million. Future development plans have been established based on an expectation of available cash flows from operations and availability of funds under our revolving credit facility.

We employ technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques.

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The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for our proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2016, are summarized as follows (in thousands of dollars):

	Proved Developed		Proved Undeveloped		Total			
As of December 31,	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2014	$ 295,554	$ 185,566	$ 864,024	$ 312,073	$ 1,159,578	$ 497,639	$ 154,351	$ 343,288
2015	$ 70,834	$ 60,962	$ 1,098	$ 233	$ 71,932	$ 61,195	$ 2,393	$ 58,802
2016	$ 56,467	$ 46,827	$ 18,114	$ 10,403	$ 74,581	$ 57,230	$ 4,993	$ 52,237

The PV 10 Value represents the discounted future net cash flows attributable to our proved oil and gas reserves before income tax, discounted at 10%. Although this measure is not in accordance with U.S. generally accepted accounting principles (GAAP), we believe that the presentation of the PV 10 Value is relevant and useful to investors because it presents the discounted future net cash flow attributable to proved reserves prior to taking into account corporate future income taxes and the current tax structure. We use this measure when assessing the potential return on investment related to oil and gas properties. The PV 10 of future income taxes represents the sole reconciling item between this non-GAAP PV 10 Value versus the GAAP measure presented in the standardized measure of discounted cash flow. A reconciliation of these values is presented in the last three columns of the table above. The standardized measure of discounted future net cash flows represents the present value of future cash flows attributable to proved oil and natural gas reserves after income tax, discounted at 10%.

Proved developed oil and gas reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Our reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of our reserves.

In accordance with U.S. generally accepted accounting principles, product prices are determined using the twelve-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month, adjusted for oilfield or gas gathering hub and wellhead price differentials (e.g. grade, transportation, gravity, sulfur, and basic sediment and water) as appropriate. Also in accordance with SEC specifications and U.S. generally accepted accounting principles, changes in market prices subsequent to December 31 are not considered.

While it may reasonably be anticipated that the prices received for the sale of our production may be higher or lower than the prices used in this evaluation, as described above, and the operating costs relating to such production may also increase or decrease from existing levels, such possible changes in prices and costs were, in accordance with rules adopted by the SEC, omitted from consideration in making this evaluation for the SEC case. Actual volumes produced, prices received and costs incurred may vary significantly from the SEC case.

Natural gas prices, based on the twelve-month average of the first of the month Henry Hub index price, were $2.49 per MMBtu in 2016 as compared to $2.59 per MMBtu in 2015. Oil prices, based on the NYMEX monthly average price, were $43.29 per barrel in 2016 as compared to $48.66 per barrel in 2015.

Since January 1, 2017, we have not filed any estimates of our oil and gas reserves with, nor were any such estimates included in any reports to, any federal authority or agency, other than the Securities and Exchange Commission.

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District Information

The following table presents certain reserve, production and well information as of December 31, 2016.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves at Year End (MBoe)	193	766	1,280	4,244	57	6,540
Developed						
Undeveloped			289	846		1,135
Total	193	766	1,569	5,090	57	7,675
Average Daily Production (Boe per day)	279	486	1,089	1,882	50	3,786
Gross Wells	632	291	585	514	97	2,119
Net Wells	387	134	246	175	17	959
Gross Operated Wells	477	254	359	366	57	1,513

In several of our regions we operate field service groups to service our operated wells and locations as well as third party operators in the area. These services consist of well service support, site preparation and construction services for drilling and workover operations. Our operations are performed utilizing workover or swab rigs, water transport trucks, saltwater disposal facilities, various land excavating equipment and trucks we own and that are operated by our field employees.

Appalachian Region

Our Appalachian activities are concentrated primarily in West Virginia. This region is managed from our office in Charleston, West Virginia. Our assets in this region include a large acreage position and a high concentration of wells. At December 31, 2016, we had 632 wells (387 net), of which 477 wells are operated. There are multiple producing intervals that include the Big Lime, Injun, Blue Monday, Weir, Berea, Gordon and Devonian Shale formations at depths primarily ranging from 1,600 to 5,600 feet. Average net daily production in 2016 was 279 Boe. While natural gas production volumes from Appalachian reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of Appalachian reserves is relatively long. At December 31, 2016, we had 193 MBoe of proved reserves (substantially all natural gas) in the Appalachian region, constituting 3% of our total proved reserves. We maintain an acreage position of over 40,200 gross (33,400 net) acres in this region, primarily in Calhoun, Clay and Roane counties. We operate a small field service group in this region utilizing one swab rig, one paraffin truck, one saltwater hauling truck and limited excavating equipment to primarily service our own operated wells and locations. As of March 31, 2017 the Appalachian region has no wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

Gulf Coast Region

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in southeast Texas. This region is managed from our office in Houston, Texas. Principal producing intervals are in the Marg Tex, Wilcox, Pettit, Glenrose, Woodbine, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 291 wells (134 net) in the Gulf Coast region as of December 31, 2016, of which 254 wells are operated by us. Average daily production in 2016 was 486 Boe. At December 31, 2016, we had 766 MBoe of proved reserves in the Gulf Coast region, which represented 10% of our total proved reserves. We maintain an acreage position of over 20,000 gross (9,500 net) acres in this region, primarily in Dimmit, Duval and

Polk counties. We operate a field service group in this region from a field office in Carrizo Springs, Texas utilizing 3 workover rigs, 18 water transport trucks, two saltwater disposal well and several trucks and excavating equipment. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. As of March 31, 2017 the Gulf Coast region has no operated wells in the process of being drilled, no waterfloods in the process of being installed and no other related activities of material importance.

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Mid-Continent Region

Our Mid-Continent activities are concentrated in central Oklahoma. This region is managed from our office in Oklahoma City, Oklahoma. As of December 31, 2016, we had 585 wells (246 net) in the Mid-Continent area, of which 359 wells are operated by us. Principal producing intervals are in the Roberson, Avant, Skinner, Sycamore, Bromide, McLish, Hunton, Mississippian, Oswego, Red Fork, and Chester formations at depths ranging from 1,100 to 10,500 feet. Average net daily production in 2016 was 1,089 Boe. At December 31, 2016, we had 1569 MBoe of proved reserves in the Mid-Continent area, or 20% of our total proved reserves. We maintain an acreage position of over 86,000 gross (29,000 net) acres in this region, primarily in Canadian, Kingfisher , Grant and Garvin counties. We operate a field service group in this region from a field office in Elmore City, utilizing one workover rig and 1 saltwater hauling truck. Our Mid-Continent region is actively participating with third party operators in the horizontal development of lands that include Company owned interest in several counties in the Stack and Scoop plays of Oklahoma where drilling is primarily targeting reservoirs of the Mississippian, Woodford, and Hunton formations. As of March 31, 2017, the Mid-Continent region has participated in the drilling and completion of two wells included as Proved Undeveloped at year-end. In addition, the Company is currently participating, with 11.8% working interest, in the drilling of a horizontal well operated by Marathon Corporation in Kingfisher County targeting a Mississippian interval.

West Texas Region

Our West Texas activities are concentrated in the Permian Basin in Texas and New Mexico. The Spraberry field was discovered in 1949, encompasses eight counties in West Texas and the Company believes it is the largest oil field in the United States. The field is approximately 150 miles long and 75 miles wide at its widest point. The oil produced is West Texas Intermediate Sweet, and the gas produced is casing-head gas with an average energy content of 1,400 Btu. The oil and gas are produced primarily from six formations; the upper and lower Spraberry, the Dean, the Wolfcamp, the Strawn and the Atoka, at depths ranging from 6,700 feet to 11,300 feet. This region is managed from our office in Midland, Texas. As of December 31, 2016, we had 514 wells (175 net) in the West Texas area, of which 366 wells are operated by us. Principal producing intervals are in the Spraberry, Wolfcamp and San Andres formations at depths ranging from 5,500 to 12,500 feet. Average net daily production in 2016 was 1,882Boe. At December 31, 2016, we had 5090 MBoe of proved reserves in the West Texas area, or 66% of our total proved reserves. We maintain an acreage position of over 19,600 gross (11,860 net) acres in the Permian Basin in West Texas, primarily in Reagan, Upton, Martin and Midland counties and believe this acreage has significant resource potential for horizontal drilling in the Spraberry and Wolfcamp intervals. We operate a field service group in this region utilizing 8 workover rigs, 4 hot oiler trucks and 1 kill truck. Services including well service support, site preparation and construction services for drilling and workover operations are provided to third party operators as well as utilized in our own operated wells and locations. At December 31, 2016 the Company had identified and committed to participate in 18 Proved Undeveloped horizontal drilling locations. As of March 31, 2017 all 18 of these wells have been drilled and are either on production or are in the process of being fracture stimulated. In addition, the Company is currently participating for 38.25% working interest in the drilling of six horizontal wells operated by Apache that are targeting the Wolfcamp Formation.

Item 3. LEGAL PROCEEDINGS.

None.

Item 4. MINE SAFETY DISCLOSURES.

Not applicable.

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PART II

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

Our common stock is listed and principally traded on the NASDAQ Stock Market under the ticker symbol PNRG . The following table presents the high and low prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system.

	High	Low
2016		
First Quarter	$ 52.00	$ 33.39
Second Quarter	63.00	27.50
Third Quarter	61.00	48.01
Fourth Quarter	58.99	43.25
2015		
First Quarter	$ 73.00	$ 52.01
Second Quarter	59.80	50.01
Third Quarter	77.00	50.79
Fourth Quarter	72.53	45.31

The above quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not represent actual transactions.

As of March 31, 2017, there were 453 registered holders of the common stock.

No dividends have been declared or paid during the past two years on our common stock. Provisions of our line of credit agreement restrict our ability to pay dividends. Such dividends may be declared out of funds legally available therefore, when and as declared by our Board of Directors.

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Issuer Purchases of Equity Securities

In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012, the Board of Directors of the Company approved an additional 500,000 shares of the Company s stock to be included in the stock repurchase program. A total of 3,500,000 shares have been authorized, to date, under this program. Through December 31, 2016, a total of 3,262,953 shares have been repurchased under this program for $ 55,129,650 at an average price of $16.90 per share. Additional purchases of shares may occur as market conditions warrant. We expect future purchases will be funded with internally generated cash flow or from working capital.

2016 Month	Number of Shares	Average Price Paid per share	Maximum Number of Shares that May Yet Be Purchased Under The Program at Month-End
January	10,070	$ 47.96	248,158
February			248,158
March	61	34.72	248,097
April	143	32.03	247,954
May	446	42.42	247,508
June			247,508
July			247,508
August			247,508
September			247,508
October	99	57.57	247,409
November	83	49.71	247,326
December	10,279	55.90	237,047
Total / Average	21,181	$ 51.60	

Item 6. SELECTED FINANCIAL DATA

We are a smaller reporting company and therefore no response is required pursuant to this Item.

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

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Report contains additional information that should be referred to when reviewing this material. Our subsidiaries are listed in Note 1 to the Consolidated Financial Statements.

Overview:

We are an independent oil and natural gas company engaged in acquiring, developing and producing oil and natural gas. We presently own producing and non-producing properties located primarily in Texas, Oklahoma, West Virginia, New Mexico, Colorado and Louisiana. In addition, we own a substantial amount of well servicing equipment. All of our oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential. We believe our balanced portfolio of assets and our ongoing hedging program position us well for both the current commodity price environment and future potential upside as we develop our attractive resource opportunities. Our primary sources of liquidity are cash generated from our operations and our credit facility.

We attempt to assume the position of operator in all acquisitions of producing properties and will continue to evaluate prospects for leasehold acquisitions and for exploration and development operations in areas in which we own interests. We continue to actively pursue the acquisition of producing properties. In order to diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets so as to build stockholder value through consistent growth in our oil and gas reserve base on a cost-efficient basis.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We use derivative instruments to manage our commodity price risk. This practice may prevent us from receiving the full advantage of any increases in oil and gas prices above the maximum fixed amount specified in the derivative agreements and subjects us to the credit risk of the counterparties to such agreements. Since all of our derivative contracts are accounted for under mark-to-market accounting, we expect continued volatility in gains and losses on mark-to-market derivative contracts in our consolidated statement of operations as changes occur in the NYMEX price indices.

Market Conditions and Commodity Prices:

Our financial results depend on many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Commodity prices are affected by many factors outside of our control, including changes in market supply and demand, which are impacted by weather conditions, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. In addition, our realized prices are further impacted by our derivative and hedging activities. As a result, we cannot accurately predict future commodity prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases in these prices will have on our capital program, production volumes or revenues. Location differentials have increased in certain regions, such as in the Appalachian region, resulting in further declines in natural gas prices. We expect natural gas and crude oil prices to remain volatile. In addition to production volumes and commodity prices, finding and developing sufficient amounts of natural gas and crude oil reserves at economical costs are critical to our long-term success.

Critical Accounting Estimates:

Proved Oil and Gas Reserves

Proved oil and gas reserves directly impact financial accounting estimates, including depreciation, depletion and amortization. Proved reserves represent estimated quantities of natural gas, crude oil, condensate, and natural gas liquids that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. The process of estimating quantities of proved oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upward or downward) to existing reserve estimates may occur from time to time.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depletion expense and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease respectively. Depreciation, depletion and amortization of the cost of proved oil and gas properties are calculated using the unit-of-production method. The reserve base used to calculate depletion, depreciation or amortization is the sum of proved developed reserves and proved undeveloped reserves for leasehold acquisition costs and the cost to acquire proved properties. The reserve base includes only proved developed reserves for lease and well equipment costs, which include development costs and successful exploration drilling costs. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Liquidity and Capital Resources:

Our primary sources of liquidity are cash generated from our operations, through our producing oil and gas properties, field services business and sales of acreage.

Net cash provided by operating activities for the year ended December 31, 2016 was $11.0 million, compared to $21 million in the prior year. Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control.

Our realized oil and gas prices vary due to world political events, supply and demand of products, product storage levels, and weather patterns. We sell the vast majority of our production at spot market prices. Accordingly, product price volatility will affect our cash flow from operations. To mitigate price volatility we sometimes lock in prices for some portion of our production through the use of derivatives.

If our exploratory drilling results in significant new discoveries, we will have to expend additional capital in order to finance the completion, development, and potential additional opportunities generated by our success. We believe that, because of the additional reserves resulting from the successful wells and our record of reserve growth in recent years, we will be able to access sufficient additional capital through bank financing.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2017, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2017 capital budget is reflective of decreased commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity we may adjust our capital program throughout the year, divest assets, or enter into strategic joint ventures. We are actively in discussions with financial partners for funding to develop our asset base and, if required, pay down our revolving credit facility should our borrowing base become limited due to the deterioration of commodity prices.

On February 15, 2017, the Company and its lenders entered into a Third Amended and Restated Credit Agreement with a maturity date of February 15, 2021, providing for a credit facility totaling $300 million, with a borrowing base of $75 million. As of March 31, 2017 the Company has $24.8 million in outstanding borrowings and $40.2 million in availability under this facility. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. The next borrowing base review is scheduled for June 2017. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial and operational covenants defined in the agreement. We are currently in compliance with these covenants and expect to be in compliance over the next twelve months. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and/or declare all principal and interest immediately due and payable. Our borrowing base may decrease as a result of lower natural gas or oil prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for other reasons set forth in our revolving credit agreement. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base.

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Our credit agreement required us to hedge a portion of our production as forecasted for the PDP reserves included in our borrowing base review engineering reports. Accordingly the Company has in place the following swap agreements for oil and natural gas.

		Monthly Hedge Volumes		Price	
	Year	BBLs	MMBTU	BBLs	MMBTU
January through December	2017	14,300	235,000	$ 50.10	$ 3.11
January through December	2018	11,900	200,000	$ 52.02	$ 2.97
January through March	2019	12,500	130,000	$ 50.75	$ 3.12

In accordance with SEC rules governing the scheduling of the drilling of PUD reserves we have only included in our yearend reserve report, the 18 PUD locations for which we have an AFE and a definitive plan to drill. As described below, additional capital expenditures are expected in both our West Texas and Oklahoma regions.

Our West Texas horizontal drilling program began in 2015 with the drilling of two wells. Through December 31, 2016 we have drilled and completed eight wells. Development is continuing and we are currently participating in an additional 19 horizontal wells in this program. As of March 31, 2017, these wells are in various stages of being drilled, completed, have been placed on production, or are waiting on hydraulic fracture stimulation. We anticipate the drilling of an additional 13 wells in 2017, although AFEs and specific plans for drilling have not been received. Although the actual count may vary, this additional activity brings the anticipated total to 32 horizontal wells drilled in 2017 in our West Texas horizontal drilling program. In addition, the Company is participating for less than 1% interest in 13 other horizontal wells.

In Upton County, Texas, we are developing a contiguous 3,900 acre block with our joint venture partner, Apache Corporation, where the Company holds approximately 48% interest in 2,606 gross acres. Through yearend 2016 six wells had been drilled and completed. In the first quarter of 2017 an additional eight wells have been spud and are in various stages of being drilled or completed. Apache Corporation has indicated their plans to PAD drill the acreage and that future phases of the development will result in approximately 60 horizontal wells being drilled at a cost of about $470 million. We own various interests ranging from 14% to 49% in the lands to be developed in this project and expect our share of these capital expenditures to be approximately $120 million. The actual number of wells to be drilled and the timing of the drilling may vary based on commodity market conditions. Apache drilling plans indicate an additional nine wells will be drilled later this year at a cost of $60 million, of which our share is approximately $19 million. These wells meet the definition of proved undeveloped reserves, however, they were not included in our yearend reserve report because we had not yet received AFEs and formal drilling plans. Also in Upton County, the Company is participating for 4% interest with Apache in the development of a 640 acre block where six wells, that were spud in 2016, have been completed and are on production as of March 31, 2017. These wells were included in our year end reserve report as Proved Undeveloped Reserves.

In 2016 we commenced our Martin County, Texas horizontal drilling program with the drilling of two wells that began production in July, 2016. These wells were drilled on a 960 acre block that the Company is developing with RSP Permian. An additional two wells were spud in the fourth quarter of 2016 and as of March 31, 2017, they are both producing. These two wells were included as PUDs in our yearend reserve report with the Company owning 35% to 38% interest. RSP Permian drilling plans indicate an additional two wells will be drilled in 2017, however, these were not included in the reserves report, as AFEs for these have not yet been received.

The Company maintains an acreage position of 21,166 gross (13,021 net) acres in the Permian Basin in West Texas, primarily in Reagan, Upton, Midland and Martin counties. We believe this acreage has significant resource potential in multiple Spraberry and Wolfcamp intervals that support the potential drilling of as many as 250 additional wells.

Our Oklahoma horizontal development program, which began in 2012, has participated in 24 horizontal wells for approximately $23 million through the first quarter of 2017. Over this same time period the Company choose to retain an over-riding royalty interest in 21 other horizontal wells. Presently the Company is participating with 17.6% interest in a horizontal well in Canadian County operated by Devon Energy and with 11.8% interest in a horizontal well in Kingfisher County operated by Marathon Oil Company. Our share of these two wells will be approximately $2.2 Million. We have also elected to retain an ORRI in two additional horizontal wells currently being drilled in Garfield and Canadian counties. In addition, we are currently participating for 50% interest in a vertical well in Garvin County with an expected cost, net to PrimeEnergy, of $1.3 Million. As of March 31, 2017, all five wells have been spud and are either drilling, in the process of being completed and production tested, or are waiting on hydraulic fracture stimulation. The horizontal activity on company acreage is primarily focused in Canadian, Garvin, Grady and Kingfisher counties where we have approximately 2,295 net acres. We believe our acreage has significant additional resource potential that could support the drilling of 78 new horizontal wells based on an estimate of only two wells per section with our share of the capital expenditure being about $42 Million at an average 10.5% ownership level.

In 2016, the limited partners of the Company managed drilling funds, located in West Virginia, voted to terminate the partnerships, sell the wells to the Company and retain their proportionate share of the leases previously held by those partnerships. These leases may potentially see future development should the horizontal shale plays of the Appalachian Basin expand into these areas.

To supplement cash flow and finance our drilling program we have sold or farmed out certain acreage in exchange for cash and a royalty or working interest in both West Texas and Oklahoma. During 2016 proceeds under these agreements were approximately $34.4 million and during the first quarter of 2017 we have closed on transactions for an additional $46.9 million.

As of March 2017, the Company has $6.3 million outstanding on our equipment financing facilities which are secured by substantially all of our field service equipment. The majority of our capital spending is discretionary, and the ultimate level of expenditures will be dependent on our assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2016 was $1.3 million. The Company expects continued spending under these programs in 2017.

Results of Operations:

2016 and 2015 Compared

We reported net income for 2016 of $3.3 million, or $ 1.50 per share, compared to a net loss for 2015 of $12.8 million, or $ 5.53 per share. Gains related to the sale of acreage during 2016 combined with reductions in expenses offset declines oil and gas sales compared to 2015. The significant components of net income are discussed below.

Oil and gas sales decreased $7.3 million, or 16.0% to $38.3 million for the year ended December 31, 2016 from $45.6 million for the year ended December 31, 2015. Crude oil and natural gas sales vary due to changes in volumes of production sold and realized commodity prices. Our realized prices at the well head decreased an average of $5.96 per barrel, or 13% on crude oil and decreased $0.15 per Mcf, or 5.5% on natural gas during 2016 as compared to 2015.

Our crude oil production decreased by 50,000 barrels, or 6.9% from 720,000 barrels for the year ended December 31, 2015 to 670,000 barrels for the year ended December 31, 2016. Our natural gas production

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decreased by 150 MMcf, or 3.23% from 4,696 MMcf for the year ended December 31, 2015 to 4,546 MMcf for the year ended December 31, 2016. The decrease in crude oil and natural gas production volumes are a result of the natural decline of existing properties offset by our continued drilling success in the West Texas and Oklahoma regions as we place new wells into production.

The following table summarizes the primary components of production volumes and average sales prices realized for the years ended December 31, 2016 and 2015 (excluding realized gains and losses from derivatives).

	Year Ended December 31,		**Increase (Decrease)**	
	2016	**2015**	**Amount**	**Percent**
Barrels of Oil Produced	670,000	720,000	(50,000)	-6.9%
Average Price Received (excluding the impact of derivatives)	$ 39.78	$ 45.74	$ (5.96)	-13.0%
Oil Revenue (In 000 s)	$ 26,655	$ 32,923	$ (6,305)	19.2%
Mcf of Gas Produced	4,546,000	4,696,000	(150,000)	-3.2%
Average Price Received (excluding the impact of derivatives)	$ 2.56	$ 2.71	$ (0.15)	-5.5%
Gas Revenue (In 000 s)	$ 11,651	$ 12,709	$ (1,037)	-8.2%
Total Oil & Gas Revenue (In 000 s)	$ 38,306	$ 45,632	$ (7,342)	-16.1%

Realized net gains (losses) on derivative instruments, net include net losses of $0.04 million and net gains of $0.02 million on the settlements of crude oil and natural gas derivatives, respectively for the year ended December 31, 2016. This item included net gains of $18.1 million and $3.0 million on the settlements of crude oil and natural gas derivatives, respectively for the year ended December 31, 2015.

Oil and gas prices received including the impact of derivatives were:

	Year Ended December 31,		**Increase (Decrease)**	
	2016	**2015**	**Amount**	**Percent**
Oil Price	$ 39.73	$ 70.93	$ (31.20)	(44.0)%
Gas Price	$ 2.57	$ 3.35	$ (0.15)	(23.4)%

We do not apply hedge accounting to any of our commodity based derivatives thus changes in the fair market value of commodity contracts held at the end of a reported period, referred to as mark-to-market adjustments, are recognized as unrealized gains and losses in the accompanying consolidated statements of operations. As oil and natural gas prices remain volatile, mark-to-market accounting treatment creates volatility in our revenues. During the year ended December 31, 2016 we recognized net unrealized losses of $1.7 million associated with crude oil fixed swaps and $1.9 million associated with natural gas fixed swap contracts due to market fluctuations in natural gas and crude oil futures market prices between July 2016 and December 31, 2016. During the year ended December 31, 2015, we recognized net unrealized losses of $14.6 million associated with crude oil fixed swaps and collars and $2.3 million associated with natural gas fixed swap contracts due to market fluctuations in natural gas and crude oil futures market prices between January 1, 2015 and December 31, 2015.

Field service income decreased $5.5 million, or 26.3% from $20.9 million for the year ended December 31, 2015 to $15.4 million for the year ended December 31, 2016. We reduced rates on our workover rig and hot oiler services during 2016 in response to the reduced commodity prices. This decrease was offset by increases in our SWD income related to increased utilization of the pipeline and capacity upgrades added during 2015 and 2016.

Lease operating expense decreased $7.7 million, or 21.9% from $35.2 million for the year ended December 31, 2015 to $27.5 million for the year ended December 31, 2016. This decrease was largely due to cost reductions from suppliers and improved operational efficiencies.

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Field service expense decreased $5.1 million, or 29.0% from $17.6 million for the year ended December 31, 2015 to $12.5 million for the year ended December 31, 2016. Field service expenses primarily consist of salaries and vehicle operating expenses which have been reduced during 2016 in response to falling rates and utilization of our equipment services.

Depreciation, depletion, amortization and accretion on discounted liabilities remained relatively flat decreasing $1.4 million, or 4.4% from $31.6 million for the year ended December 31, 2015 to $30.2 million for the year ended December 31, 2016. The DD&A expense is primarily attributable to our properties in West Texas and Oklahoma.

General and administrative expense decreased $4.5 million, or 36.6% from $12.3 million for the year ended December 31, 2015 to $7.8 million for the year ended December 31, 2016 related to reductions in personnel costs, including salaries and employee related taxes and insurance.

Gain on sale and exchange of assets of $32.4 million for the year ended December 31, 2016 and $1.4 million for the year ended December 31, 2015 consists of sales of non-producing acreage and oil and gas interests and non-essential field service equipment.

Interest expense decreased $0.1 million, or 2.8% from $3.6 million for the year ended December 31, 2015 to $3.5 million for the year ended December 31, 2016. This decrease relates to a decrease in average debt outstanding during 2016 as compared to 2015 combined with an increase in weighted average interest rates during the 2016 periods. The average interest rate paid on outstanding bank borrowings subject to interest during 2016 and 2015 were 3.93% and 3.44%, respectively. As of December 31, 2016 and 2015, the total outstanding borrowings were $69.2 million and $95.6 million, respectively.

A tax provision of $2.1 million, or an effective rate of 38% was recorded for the year ended December 31, 2016, versus a tax benefit of $6.65 million, or an effective rate of 34% for the year ended December 31, 2015. The tax rate was higher in 2016 primarily due to higher income in Oklahoma, which has a 6% corporate tax rate, as opposed to Texas whose rate is less than 1%, along with the settlement of an IRS audit for the year 2014.

Item 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company and therefore no response is required pursuant to this Item.

Item 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The consolidated financial statements and supplementary information included in this Report are described in the Index to Consolidated Financial Statements at Page F-1 of this Report.

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

None.

Item 9A. CONTROLS AND PROCEDURES.

As of the end of the period covered by this Annual Report on Form 10-K, our principal executive officer and principal financial officer have evaluated the effectiveness of our disclosure controls and procedures (Disclosure Controls). Disclosure Controls, as defined in Rule 13a-15(e) of the Securities Exchange Act of 1934, as amended (the Exchange Act), are procedures that are designed with the objective of ensuring that information required to be disclosed in our reports filed under the Exchange Act, such as this Annual Report, is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange

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Commission s rules and forms. Disclosure Controls are also designed with the objective of ensuring that such information is accumulated and communicated to our management, including the chief executive officer and chief financial officer, as appropriate to allow timely decisions regarding required disclosure.

Our management, including the chief executive officer and chief financial officer, does not expect that our Disclosure Controls will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the Company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

Members of our management, including our chief executive officer and chief financial officer, have evaluated the effectiveness of our disclosure controls and procedures, as defined by paragraph (e) of Exchange Act Rules 13a-15 or 15d-15, as of December 31, 2016, the end of the period covered by this Report. Based upon that evaluation, these officers concluded that our disclosure controls and procedures were effective as of December 31, 2016.

Management s Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. Our internal control over financial reporting is a process designed to provide reasonable assurance that assets are safeguarded against loss from unauthorized use or disposition, transactions are executed in accordance with appropriate management authorization and accounting records are reliable for the preparation of financial statements in accordance with U.S. generally accepted accounting principles.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2016. Management based this assessment on criteria for effective internal control over financial reporting described in Internal Control Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management s assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of its internal control over financial reporting. Management reviewed the results of its assessment with the Audit Committee of our Board of Directors.

Based on this assessment, management believes that the Company maintained effective internal control over financial reporting as of December 31, 2016.

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

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There have been no changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.
None.

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PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company s Directors, nominees for Directors and executive officers will be included in the Company s definitive proxy statement relating the Company s Annual Meeting of Stockholders to be held in June, 2017 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

Item 11. EXECUTIVE COMPENSATION.

Information relating to executive compensation will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in June, 2017, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

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

Information relating to security ownership of certain beneficial owners and management will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in June, 2017, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

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

Information relating to certain transactions by Directors and executive officers of the Company will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in June, 2017, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

Item 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

Information relating to principal accountant fees and services will be included in the Company s definitive proxy statement relating to the Company s Annual Meeting of Stockholders to be held in June, 2017, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2016, and which is incorporated herein by reference.

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PART IV

Item 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

The following documents are filed as part of this Report:

1. Financial statements (Index to Consolidated Financial Statements at page F-1 of this Report)

2. Financial Statement Schedules (Index to Consolidated Financial Statements Supplementary Information at page F-1 of this Report)

3. Exhibits:

Exhibit No.	
3.1	Restated Certificate of Incorporation of PrimeEnergy Corporation (effective July 1, 2009) (Incorporated by reference to Exhibit 3.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009).
3.2	Bylaws of PrimeEnergy Corporation as amended and restated as of May 20, 2015 (filed as Exhibit 3.2 of PrimeEnergy Corporation Form 8-K on May 21, 2015 and incorporated herein by reference).
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004).
10.22.5.10	Third Amended and Restated Credit Agreement dated as of February 15, 2017 among PrimeEnergy Corporation, as Borrower, Compass Bank, as Administrative Agent and Lender, Wells Fargo, National Association, as Document Agent, the Lenders Party Hereto (Compass Bank, Wells Fargo, National Association,Citibank, N.A.)and BBVA Compass Bank, as Letter of Credit Issuer and Sole Lead Arranger and Sole Bookrunner (filed herewith).
10.22.5.11	Amended, Restated and Consolidated Guaranty dated as of February 15, 2017, among PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Prime Offshore L.L.C. in favor of Compass Bank, as Administrative Agent for the Lenders (filed herewith).
10.22.5.12	Amended, Restated and Consolidated Pledge and Security Agreement dated as of February 15, 2017, among PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Prime Offshore L.L.C. and Compass Bank, as Administrative Agent for the Secured Parties (filed herewith).
10.23.1	Loan and Security Agreement dated July 31, 2013, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.23.1 to PrimeEnergy Corporation Form 10-Q for

	the quarter ended September 30, 2013).
10.23.2	Business Purpose Promissory Note dated July 31, 2013, made by Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company to JP Morgan Chase Bank N.A. (Incorporated by reference to Exhibit 10.23.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).
10.23.3	Guaranty dated July 31, 2013, made by PrimeEnergy Corporation in favor of JP Morgan Chase Bank, N.A. (Incorporated by reference to Exhibit 10.23.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).

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Exhibit No.	
10.23.4	Agreement of Equipment Substitution dated January 15, 2014, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.23.4 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2014).
10.24.1	Loan and Security Agreement dated July 29, 2014, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.24.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2014).
10.24.2	Business Purpose Promissory Note dated July 29, 2014, made by Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company to JP Morgan Chase Bank N.A. (Incorporated by reference to Exhibit 10.24.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2014).
10.24.3	Guaranty dated July 29, 2014, made by PrimeEnergy Corporation in favor of JP Morgan Chase Bank, N.A. (Incorporated by reference to Exhibit 10.24.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2014).
10.25	Purchase and Sale Agreement dated as of January 25, 2017, among PrimeEnergy Corporation, PrimeEnergy Management Corporation, PrimeEnergy Operating Company, PrimeEnergy Asset and Income Fund, L.P. A-2, PrimeEnergy Asset and Income Fund, L.P. A-3, PrimeEnergy Asset and Income Fund, L.P. AA-2, and PrimeEnergy Asset and Income Fund, L.P. AA-4, as Sellers and Guidon Operating LLC, as Purchaser (filed herewith).
14	PrimeEnergy Corporation Code of Business Conduct and Ethics, as amended December 16, 2011 (Incorporated by reference to Exhibit 14 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2011).
21	Subsidiaries (filed herewith).
23	Consent of Ryder Scott Company, L.P. (filed herewith).
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Summary Reserve Report dated March 20, 2016, of Ryder Scott Company, L.P. (filed herewith).
101.INS	XBRL (eXtensible Business Reporting Language) Instance Document (filed herewith)
101.SCH	XBRL Taxonomy Extension Schema Document (filed herewith)

101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith)
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (filed herewith)
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (filed herewith)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith)

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 17th day of April, 2017.

PrimeEnergy Corporation

By: /s/ CHARLES E. DRIMAL, JR.
Charles E. Drimal, Jr.
Chairman, Chief Executive Officer and President

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report has been signed below by the following persons on behalf of the Registrant and in the capacities indicated and on the 17th day of April, 2017.

/s/ CHARLES E. DRIMAL, JR.	Chairman, Chief Executive Officer and President;
Charles E. Drimal, Jr.	The Principal Executive Officer
/s/ BEVERLY A. CUMMINGS	Director, Executive Vice President and Treasurer;
Beverly A. Cummings	The Principal Financial Officer

/s/ GAINES WEHRLE	Director	/s/ CLINT HURT	Director
Gaines Wehrle		Clint Hurt	
/s/ H. GIFFORD FONG	Director	/s/ JAN K. SMEETS	Director
H. Gifford Fong		Jan K. Smeets	
/s/ THOMAS S.T. GIMBEL	Director		
Thomas S.T. Gimbel			

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors and Stockholders of

PrimeEnergy Corporation and Subsidiaries:

We have audited the accompanying consolidated balance sheets of PrimeEnergy Corporation and Subsidiaries (the Company) as of December 31, 2016 and 2015, and related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years then ended. The Company s management is responsible for these financial statements. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of PrimeEnergy Corporation and Subsidiaries as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the years then ended, in conformity with accounting principles generally accepted in the United States of America.

GRASSI & CO., CPAs, P.C.

New York, New York

April 17, 2017

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(Thousands of dollars)

	As of December 31, 2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	$ 6,568	$ 9,750
Restricted cash and cash equivalents	3,543	3,513
Accounts receivable, net	7,400	9,543
Prepaid obligations	412	619
Other current assets	160	196
Total Current Assets	18,083	23,621
Property and Equipment		
Oil and gas properties at cost	417,821	395,129
Less: Accumulated depletion and depreciation	(230,331)	(204,213)
	187,490	190,916
Field and office equipment at cost	26,902	27,919
Less: Accumulated depreciation	(18,024)	(16,824)
	8,878	11,095
Total Property and Equipment, Net	196,368	202,011
Other Assets	203	629
Total Assets	$ 214,654	$ 226,261
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 11,965	$ 12,355
Accrued liabilities	8,184	6,122
Current portion of long-term debt	2,949	3,059
Current portion of asset retirement and other long-term obligations	1,563	1,435
Derivative liability short-term	2,547	7
Total Current Liabilities	27,208	22,978
Long-Term Bank Debt	66,316	92,581
Asset Retirement Obligations	15,943	10,452
Derivative Liability Long-Term	1,092	
Deferred Income Taxes	37,500	37,349

Other Long-Term Obligations	715	
Total Liabilities	148,774	163,360
Commitments and Contingencies		
Equity		
Common stock, $.10 par value; 2016 and 2015: Authorized: 4,000,000 shares, issued: 3,836,397 shares; outstanding 2016: 2,283,503 shares; 2015: 2,304,684 shares	383	383
Paid-in capital	8,313	7,854
Retained earnings	96,322	92,878
Accumulated other comprehensive loss, net		(5)
Treasury stock, at cost; 2016: 1,542,894; 2015: 1,531,713 shares	(46,473)	(45,380)
Total Stockholders Equity PrimeEnergy	58,545	55,730
Non-controlling interest	7,335	7,171
Total Equity	65,880	62,901
Total Liabilities and Equity	$ 214,654	$ 226,261

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

(Thousands of dollars, except per share amounts)

	For the Year Ended December 31, 2016	For the Year Ended December 31, 2015
Revenues		
Oil and gas sales	$ 38,306	$ 45,632
Realized (loss) gain on derivative instruments, net	(16)	21,151
Field service income	15,432	20,879
Administrative overhead fees	6,567	8,287
Unrealized (loss) gain on derivative instruments	(3,582)	(16,901)
Other income	59	58
Total Revenues	56,766	79,106
Costs and Expenses		
Lease operating expense	27,544	35,206
Field service expense	12,549	17,641
Depreciation, depletion, amortization and accretion on discounted liabilities	30,174	31,551
General and administrative expense	7,849	12,267
Total Costs and Expenses	78,116	96,665
Gain on Sale and Exchange of Assets	32,378	1,386
Income (Loss) from Operations	11,028	(16,173)
Other Income and Expenses		
Less: Interest expense	3,507	3,627
Add: Interest income	1	2
Income (Loss) Before Provision (Benefit) for Income Taxes	7,522	(19,798)
Provision (Benefit) for Income Taxes	2,100	(6,648)
Net Income (Loss)	5,422	(13,150)
Less: Net Income (Loss) Attributable to Non-Controlling Interest	1,978	(366)
Net Income (Loss) Attributable to PrimeEnergy	$ 3,444	$ (12,784)
Basic Income (Loss) Per Common Share	$ 1.50	$ (5.53)
Diluted Income (Loss) Per Common Share	$ 1.13	$ (5.53)

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(Thousands of dollars)

	For the Year Ended December 31,	
	2016	**2015**
Net Income (Loss)	$ 5,422	$ (13,150)
Other Comprehensive Income, net of taxes:		
Changes in fair value of hedge positions, net of taxes of $(2) and $(50), respectively	5	87
Total other comprehensive income	5	87
Comprehensive income (loss)	5,427	(13,063)
Less: Comprehensive income (loss) attributable to non-controlling interest	1,978	(366)
Comprehensive Income (loss) attributable to PrimeEnergy	$ 3,449	$ (12,697)

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

(Thousands of dollars)

	Common Stock				**Accumulated Other Comprehensive**				
	Shares	**Amount**	**Additional Paid-In Capital**	**Retained Earnings**	**Income (Loss)**	**Treasury Stock**	**Total Stockholders Equity PrimeEnergy**	**Non-Controlling Interest**	**Total Equity**
Balance at December 31, 2014	3,836,397	$ 383	$ 7,186	$ 105,662	$ (92)	$ (43,527)	$ 69,612	$ 8,648	$ 78,260
Purchase 28,720 shares of common stock						(1,853)	(1,853)		(1,853)
Net loss				(12,784)			(12,784)	(366)	(13,150)
Other comprehensive income, net of taxes					87		87		87
Purchase of non-controlling interest			668				668	(1,077)	(409)
Distributions to non-controlling interest								(34)	(34)
Balance at December 31, 2015	3,836,397	$ 383	$ 7,854	$ 92,878	$ (5)	$ (45,380)	$ 55,730	$ 7,171	$ 62,901
Purchase 21,181 shares of common stock						(1,093)	(1,093)		(1,093)
Net income				3,444			3,444	1,978	5,422
Other comprehensive income, net of taxes					5		5		5
Purchase of non-controlling interest			459				459	(683)	(224)
Distributions to non-controlling interest								(1,131)	(1,131)
Balance at December 31, 2016	3,836,397	$ 383	$ 8,313	$ 96,322	$	$ (46,473)	$ 58,545	$ 7,335	$ 65,880

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of dollars)

	For the Year Ended December 31, 2016	2015
Cash Flows from Operating Activities:		
Net Income (loss)	$ 5,422	$ (13,150)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	30,174	31,551
Gain on sale of properties	(32,378)	(1,386)
Unrealized loss on derivative instruments	3,582	16,856
Provision for deferred income taxes	147	(6,389)
Changes in assets and liabilities:		
Decrease in accounts receivable	2,143	2,769
Increase (Decrease) in due from related parties	(25)	308
Decrease in inventories	61	64
Decrease in prepaid expenses and other assets	207	410
Decrease in accounts payable	(390)	(3,539)
Increase (Decrease) in accrued liabilities	2,062	(6,280)
Net Cash Provided by Operating Activities	11,005	21,214
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(20,843)	(14,550)
Proceeds from sale of properties and equipment	35,226	1,926
Net Cash Provided by (Used in) Investing Activities	14,383	(12,624)
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(1,093)	(1,853)
Purchase of non-controlling interests	(224)	(409)
Increase in long-term bank debt and other long-term obligations	13,500	27,700
Repayment of long-term bank debt and other long-term obligations	(39,910)	(33,453)
Distribution to non-controlling interest	(843)	(34)
Net Cash Used in Financing Activities	(28,570)	(8,049)
Net Decrease (Increase) in Cash and Cash Equivalents	(3,182)	541
Cash and Cash Equivalents at the Beginning of the Year	9,750	9,209
Cash and Cash Equivalents at the End of the Year	$ 6,568	$ 9,750

Supplemental Disclosures:		
Income taxes paid during the year	$ 120	$ 410
Interest paid during the year	$ 3,476	$ 3,695

The accompanying Notes are an integral part of these Consolidated Financial Statements

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Corporation (PEC), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Corporation and its subsidiaries are herein referred to as the Company. The Company owns leasehold, mineral and royalty interests in producing and non-producing oil and gas properties across the United States, including Colorado, Kansas, Louisiana, Mississippi, Montana, New Mexico, North Dakota, Oklahoma, Texas, West Virginia and Wyoming and the Gulf of Mexico. The Company operates over 1,200 active wells and owns non-operating interests in approximately 400 additional wells. Additionally, the Company provides well-servicing support operations, site-preparation and construction services for oil and gas drilling and reworking operations, both in connection with the Company s activities and providing contract services for third parties. The Company is publicly traded on the NASDAQ under the symbol PNRG. PEC owns Eastern Oil Well Service Company (EOWSC), EOWS Midland Company (EMID) and Southwest Oilfield Construction Company (SOCC), all of which perform oil and gas field servicing. PEC also owns Prime Operating Company (POC), which serves as operator for most of the producing oil and gas properties owned by the Company and affiliated entities. PEC also owns Prime Offshore L.L.C. (Prime Offshore), formerly F-W Oil Exploration LLC, which has owned and operated properties in the Gulf of Mexico. PrimeEnergy Management Corporation (PEMC), a wholly-owned subsidiary, acts as the managing general partner, providing administration, accounting and tax preparation services for 7 limited partnerships and 2 trusts (collectively, the Partnerships). The markets for the Company s products are highly competitive, as oil and gas are commodity products and prices depend upon numerous factors beyond the control of the Company, such as economic, political and regulatory developments and competition from alternative energy sources.

Consolidation and Presentation:

The consolidated financial statements include the accounts of PrimeEnergy Corporation, its subsidiaries and the Partnerships, using the full consolidation method for those partnerships which are controlled by the Company. The proportionate consolidation method is used to account for those undivided interests in oil and gas properties owned by the Company as well as interests held in unincorporated legal entities, such as partnerships, engaged in oil and gas production, which are not controlled by the Company. For those entities which are proportionately consolidated, the proportionate share of each entity s assets, liabilities, revenue and expenses is included in the appropriate classifications in the consolidated financial statements. Reserve estimates associated with the proportionately consolidated oil and gas interests are calculated for each property at the Partnership level, and depletion, depreciation and amortization (DD&A) rates are determined at the Partnership level. The Company s reserve estimates are based on the ownership percentage of Partnership reserve reports. DD&A expense and evaluation of impairment may differ from the Partnership as the Company s cost basis for the Partnership interests acquired may be different than the cost basis at the Partnership level for properties acquired by the Partnership. All significant intercompany balances and transactions are eliminated in preparing the consolidated financial statements.

Reclassifications:

Certain reclassifications have been made to prior year statements to conform with the current year presentation. These reclassifications have no impact on net income and no material impact on any other financial statement captions.

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Subsequent Events:

Subsequent events have been evaluated through the date that the consolidated financial statements were issued. During this period, there were no material subsequent items requiring disclosure other than as stated in footnote 1 and 4 to these financial statements.

Use of Estimates:

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Estimates of oil and gas reserves, as determined by independent petroleum engineers, are continually subject to revision based on price, production history and other factors. Depletion expense, which is computed based on the units of production method, could be significantly impacted by changes in such estimates. Additionally, U.S. generally accepted accounting principles require that if the expected future undiscounted cash flows from an asset are less than its carrying cost, that asset must be written down to its fair market value. As the fair market value of an oil and gas property will usually be significantly less than the total undiscounted future net revenues expected from that asset, slight changes in the estimates used to determine future net revenues from an asset could lead to the necessity of recording a significant impairment of that asset.

Property and Equipment:

The Company follows the successful efforts method of accounting for its oil and gas properties. Under the successful efforts method, costs of acquiring undeveloped oil and gas leasehold acreage, including lease bonuses, brokers fees and other related costs are capitalized. Provisions for impairment of undeveloped oil and gas leases are based on periodic evaluations. Annual lease rentals and exploration expenses, including geological and geophysical expenses and exploratory dry hole costs, are charged against income as incurred. Costs of drilling and equipping productive wells, including development dry holes and related production facilities, are capitalized. All other property and equipment are carried at cost. Depreciation and depletion of oil and gas production equipment and properties are determined under the unit-of-production method based on estimated proved developed recoverable oil and gas reserves. Depreciation of all other equipment is determined under the straight-line method using various rates based on useful lives generally ranging from 5 to 10 years. The cost of assets and related accumulated depreciation is removed from the accounts when such assets are disposed of, and any related gains or losses are reflected in current earnings.

Capitalization of Interest:

Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated and successful.

Impairment of Long-Lived Assets:

The Company reviews long-lived assets, including oil and gas properties, for impairment whenever events or changes in circumstances indicate that the carrying amounts may not be recovered. If the carrying amounts are not expected to be recovered by undiscounted cash flows, the assets are impaired and an impairment loss is recorded. The amount of impairment is based on the estimated fair value of the assets determined by discounting anticipated future net cash flows.

Fair Value:

The Company follows the authoritative guidance that establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by U.S. generally accepted

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accounting principles to be measured at fair value. The guidance defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. The guidance establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to Level 1 inputs, which consist of unadjusted quoted prices for identical instruments in active markets. Level 2 inputs consist of quoted prices for similar instruments. Level 3 valuations are derived from inputs that are significant and unobservable; hence, these valuations have the lowest priority.

Asset Retirement Obligation:

The Company follows the accounting standard for asset retirement obligation. The asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties (including removal of offshore platforms) at the end of their productive lives, in accordance with applicable state laws. The Company determined its asset retirement obligation by calculating the present value of estimated cash flows related to the liability. The asset retirement obligation is recorded as a liability at its estimated present value at its inception, with an offsetting increase to producing properties. Periodic accretion of discount of the estimated liability is recorded as an expense in the statement of operations.

Income Taxes:

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized. As of December 31, 2016 and 2015, we had no valuation allowance.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management s estimates of the ultimate outcome of various tax uncertainties.

General and Administrative Expenses:

General and administrative expenses represent cost and expenses associated with the operation of the Company.

Earnings Per Common Share:

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods.

Statements of Cash Flows:

For purposes of the consolidated statements of cash flows, the Company considers short-term, highly liquid investments with original maturities of less than ninety days to be cash equivalents.

Concentration of Credit Risk:

The Company maintains significant banking relationships with financial institutions in the State of Texas. The Company limits its risk by periodically evaluating the relative credit standing of these financial institutions. The Company s oil and gas production purchasers consist primarily of independent marketers and major gas pipeline companies.

Hedging:

The Company periodically enters into oil and gas financial instruments to manage its exposure to oil and gas price volatility. The oil and gas reference prices upon which the price hedging instruments are based reflect various market indices that have a high degree of historical correlation with actual prices received by the Company.

The financial instruments are accounted for in accordance with applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. At December 31, 2016 and 2015, the entire other comprehensive income amount is comprised of the impact of cash flow hedges. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and the hedged item over time. Any change in fair value of a derivative resulting from ineffectiveness or an excluded component of the gain/loss is recognized immediately in the statement of operations.

Recently Issued Accounting Standards:

In August 2016, the FASB issued Accounting Standards Update (ASU) 2016-15, Statement of Cash Flows (Topic 230). ASU 2016-15 seeks to reduce the existing diversity in practice in how certain cash receipts and cash payments are presented and classified in the statement of cash flows. This update is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years, with early adoption permitted. The Company is currently evaluating the provisions of ASU 2016-15 and assessing the impact, if any, it may have on its statement of consolidated cash flows.

The FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606).* This ASU supersedes the *Revenue recognition* requirements in Topic 605, Revenue Recognition and industry-specific guidance in Subtopic 932-605. *Extractivies Oil and Gas Revenue Recognition.* This ASU provides guidance concerning the recognition and measurement of revenue from contracts with customers. Its objective is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. The effective date for ASU 2014-09 was delayed through the issuance of ASU 2015-14, Revenue from Contracts with Customers Deferral of the *Effective Date,* to annual and interim periods beginning in 2018 and is required to be adopted using either the retrospective or cumulative effect (modified retrospective) transition method, with early adoption permitted in 2017. The Company is evaluating the impact this ASU will have on its consolidated financial statements and related disclosures and does not plan on early adopting.

The FASB issued ASU 2015-02, *Consolidation (Topic 810): Amendments to the Consolidation Analysis.* This ASU provides additional guidance to reporting entities in evaluating whether certain legal entities such, as

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limited partnerships, limited liability corporations and securitization structures, should be consolidated. The ASU is considered to be an improvement on current accounting requirements as it reduces the number of existing consolidation models This ASU adopted by the Company beginning January 1, 2016 did not have a material impact on the Company s consolidated financial statements and related disclosures.

The FASB issued ASU 2015-03, *Interest Imputation of Interest (Topic 835): Simplifying the Presentation of Debt Issuance Costs* and ASU 2015-15, *Interest Imputation of Interest (Topic 835): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements.* These ASU s require debt issuance costs related to a recognized debt liability, except for those related to revolving credit facilities, to be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability rather than an asset. These ASU adopted by the Company beginning January 1, 2016 did not have a material impact on the Company s consolidated financial statements and related disclosures.

The FASB issued ASU 2015-17, *Balance Sheet Classification of Deferred Taxes.* This ASU requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. This ASU is effective for annual and interim periods beginning in 2017 and can be applied prospectively or retrospectively, with early adoption permitted. This ASU was early-adopted by the Company effective January 1, 2016 and applied retrospectively, and did not have a material impact on the Company s financial statements and related disclosures.

The FASB issued ASU 2016-02, *Leases (Topic 842).* This ASU requires lessee recognition on the balance sheet of a right-of-use asset and a lease liability, initially measured at the present value of the lease payments. It further requires recognition in the income statement of a single lease cost, calculated so that the cost of the lease is allocated over the lease term on a generally straight-line basis. Finally, it requires classification of all cash payments within operating activities in the statement of cash flows. It is effective for fiscal years commencing after December 15, 2018 and early adoption is permitted. This ASU will not have a material impact on the Company s financial statements and related disclosures.

2. Acquisitions and Dispositions

Historically, the Company has repurchased the non-controlling interests of the partners and trust unit holders in certain of the Partnerships, which consist primarily of oil and gas interests. The Company purchased such non-controlling interests in an amount totaling $224,000 in 2016 and $409,000 in 2015.

During 2016, the Company has sold or farmed out interests in certain non-core undeveloped oil and natural gas properties through a number of separate, individually negotiated transactions in exchange for cash and a royalty or working interest in both West Texas and Oklahoma. Proceeds under these agreements are $34.4 million. The Company has entered into an agreement and closed on the sale of additional non-core acreage for an $46.9 million during the first quarter of 2017.

3. Additional Balance Sheet Information

Accounts receivable at December 31, 2016 and 2015 consisted of the following:

	December 31,	
(Thousands of dollars)	**2016**	**2015**

Joint interest billings	$ 2,345	$ 2,667
Trade receivables	1,070	1,452
Oil and gas sales	4,078	3,576
Other	204	2,377
	7,697	10,072
Less: Allowance for doubtful accounts	(297)	(529)
Total	$ 7,400	$ 9,543

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Accounts payable at December 31, 2016 and 2015 consisted of the following:

	December 31,	
(Thousands of dollars)	**2016**	**2015**
Trade	$ 3,967	$ 3,289
Royalty and other owners	5,909	5,973
Partner advances	592	1,083
Prepaid drilling deposits	83	390
Other	1,414	1,620
Total	$ 11,965	$ 12,355

Accrued liabilities at December 31, 2016 and 2015 consisted of the following:

	December 31,	
(Thousands of dollars)	**2016**	**2015**
Compensation and related expenses	$ 2,295	$ 2,294
Property costs	3,317	3,302
Income tax	1,988	
Other	584	526
Total	$ 8,184	$ 6,122

4. Long-Term Debt

Bank Debt:

Effective July 30, 2010 the Company entered into a Second Amended and Restated Credit Agreement between Compass Bank as agent and a syndicated group of lenders (Credit Agreement). The Credit Agreement had a revolving line of credit and letter of credit facility of up to $250 million with a final maturity date of July 30, 2017. The credit facility was secured by substantially all of the Company s oil and gas properties. The credit facility was subject to a borrowing base determined by the lenders taking into consideration the estimated value of PEC s oil and gas properties in accordance with the lenders customary practices for oil and gas loans. This process involves reviewing PEC s estimated proved reserves and their valuation. The borrowing base was redetermined semi-annually, and the available borrowing amount could be increased or decreased as a result of such redetermination. In addition, PEC and the lenders each had at their discretion the right to request the borrowing base be redetermined with a maximum of one such request each year. A revision to PEC s reserves could have prompted such a request on the part of the lenders, which would have possibly resulted in a reduction in the borrowing base and availability under the credit facility. At any time if the sum of the outstanding borrowings and letter of credit exposures exceeded the applicable portion of the borrowing base, PEC would be required to repay the excess amount within a prescribed period.

This Credit Agreement was amended from time to time to further define the limitations on loans or advances and investments made in the Company s limited partnerships; modify the Company s borrowing base and monthly reduction amounts; remove the floor rate component of LIBO rate loans; modify financial reporting requirements to the agent; increase hedging allowances; allow for a one-time advance to be made to the Company s offshore subsidiary; and amend restrictions on the payments for dividends, distributions or repurchase of PEC s stock.

The Credit Agreement included terms and covenants that require the Company to maintain a minimum current ratio, total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio and interest coverage ratio, as defined, and restrictions were placed on the payment of dividends, the amount of treasury stock the Company could purchase, commodity hedge agreements, and loans and investments in its consolidated subsidiaries and limited partnerships.

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At December 31, 2016, the credit facility borrowing base was $80 million with no required monthly reduction amount. The borrowings made within the credit facility could be placed in a base rate loan or LIBO rate loan. The Company s borrowing rates in the credit facility provided for base rate loans at the prime rate (3.75% at December 31, 2016) plus applicable margin utilization rates that ranged from 1.50% to 2.50%, and LIBO rate loans at LIBO published rates plus applicable utilization rates (2.50% to 3.50% at December 31, 2016). At December 31, 2016, the Company had in place one base rate loan and one LIBO rate loan with effective rates of 6.00% and 3.87%, respectively

At December 31, 2016, the Company had a total of $63 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 4.49% and $17 million available for future borrowings. The combined weighted average interest rate paid on outstanding bank borrowings subject to base rate and LIBO interest was 3.93% for the year ended December 31, 2016 as compared to 3.44% for the year ended December 31, 2015. The Company s borrowings under this credit facility approximates fair value because the interest rates are variable and reflective of market rates.

On February 15, 2017, the Company and its lenders entered into a Third Amended and Restated Credit Agreement (the 2017 Credit Agreement) with a maturity date of February 15, 2021. The Second Amended and Restated Credit Agreement and subsequent amendments were incorporated into the 2017 Credit Agreement. Pursuant to the terms and conditions of the 2017 Credit Agreement, the Company has a revolving line of credit and letter of credit facility of up to $300 million subject to a borrowing base that is determined semi-annually by the lenders based upon the Company s financial statements and the estimated value of the Company s oil and gas properties, in accordance with the Lenders customary practices for oil and gas loans. Currently, the Company s borrowing base is $75 million. The 2017 Credit Agreement includes terms and covenants that require the Company to maintain a minimum current ratio, total indebtedness to EBITDAX (earnings before depreciation, depletion, amortization, taxes, interest expense and exploration costs) ratio and interest coverage ratio, as defined, and restrictions are placed on the payment of dividends, the amount of treasury stock the Company may purchase, commodity hedge agreements, and loans and investments in its consolidated subsidiaries and limited partnerships. At March 31, 2017, the Company had in place one LIBO rate loan of $24.8 million outstanding with an effective rate of 3.53%.

The Company entered into interest rate hedge agreements to help manage interest rate exposure. These contracts include interest rate swaps. Interest rate swap transactions generally involve the exchange of fixed and floating rate interest payment obligations without the exchange of the underlying principal amounts. In July 2012, the Company entered into interest swap agreements for a period of two years, which commenced in January 2014, related to $75 million of the Company s bank debt resulting in a LIBO fixed rate of 0.563% and terminated in January 2016. The Company recorded interest expense and paid $7,000 and $284,000 related to the settlement of interest rate swaps for years ended December 31, 2016 and 2015, respectively.

Equipment Loans:

On July 31, 2013, the Company entered into a $10.0 million Loan and Security Agreement with JP Morgan Chase Bank (Equipment Loan). The Equipment Loan is secured by a portion of the Company s field service equipment, carries an interest rate of 3.95% per annum, requires monthly payments (principal and interest) of $184,000, and has a final maturity date of July 31, 2018. As December 31, 2016, the Company had a total of $3.34 million outstanding on this Equipment Loan.

On July 29, 2014, the Company entered into additional equipment financing facilities (Additional Equipment Loans) totaling $6.0 million with JP Morgan Chase Bank. In August 2014, the Company drew down $4.8 million of this facility that is secured by field service equipment, carries an interest rate of 3.40% per annum, requires monthly payments (principal and interest) of $87,800, and has a final maturity date of July 31, 2019. The remaining $1.2 million under the Additional Equipment Loans was available for interim draws to finance the acquisition of any future field service equipment. In December 2014, the Company made an interim

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draw of an additional $0.5 million on this facility that is secured by recently purchased field service equipment. Interim draws on this facility carried a floating interest rate, payable monthly at the LIBO published rate plus 2.50% and on June 26, 2015 converted into a fixed term loan requiring monthly payments (principal and interest) of $8,700 with a final maturity date of June 26, 2020. As of December 31, 2016, the Company had a total of $2.91 million outstanding on the Additional Equipment Loans.

The Company determined theses loans are Level 3 liabilities in the fair-value hierarchy and estimated their fair value as $6.3 million and $9.4 million at December 31, 2016 and 2015, respectively, using a discounted cash flow model.

5. Commitments

Operating Leases:

The Company has several non-cancelable operating leases, primarily for rental of office space, that have a term of more than one year. The future minimum lease payments for the operating leases at December 31, 2016 are as follows.

(Thousands of dollars)	**Operating Leases**
2017	$ 597
2018	59
Total minimum payments	$ 656

Rent expense for office space for the years ended December 31, 2016 and 2015 was $892,000 and $786,000, respectively.

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2016 and 2015 is as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2016**	**2015**
Asset retirement obligation at beginning of period	$ 11,737	$ 12,501
Liabilities incurred	68	28
Liabilities settled	(288)	(1,112)
Accretion expense	498	517
Revisions in estimated liabilities	5,490	(197)
Asset retirement obligation at end of period	$ 17,505	$ 11,737

The Company s liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive life of wells and a risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation.

Revisions to the asset retirement obligation are recorded with an offsetting change to producing properties, resulting in prospective changes to depreciation, depletion and amortization expense and accretion of discount. Because of the subjectivity of assumptions and the relatively long life of most of the Company s wells, the costs to ultimately retire the wells may vary significantly from previous estimates. During 2016 revisions in estimated liabilities for asset retirement obligations resulted from substantially lower commodity prices and increased field costs resulting in shorter productive life of marginal wells.

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6. Contingent Liabilities

The Company, as managing general partner of the affiliated Partnerships, is responsible for all Partnership activities, including the drilling of development wells and the production and sale of oil and gas from productive wells. The Company also provides the administration, accounting and tax preparation work for the Partnerships, and is liable for all debts and liabilities of the affiliated Partnerships, to the extent that the assets of a given limited Partnership are not sufficient to satisfy its obligations.

The Company is subject to environmental laws and regulations. Management believes that future expenses, before recoveries from third parties, if any, will not have a material effect on the Company s financial condition. This opinion is based on expenses incurred to date for remediation and compliance with laws and regulations, which have not been material to the Company s results of operations.

From time to time, the Company is party to certain legal actions arising in the ordinary course of business. While the outcome of these events cannot be predicted with certainty, management does not expect these matters to have a materially adverse effect on the financial position or results of operations of the Company.

7. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2016 and 2015, options on 767,500 shares were outstanding and exercisable at prices ranging from $1.00 to $1.25. According to their terms, the options have no expiration date.

8. Income Taxes

The components of the provision (benefit) for income taxes for the years ended December 31, 2016 and 2015 are as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2016**	**2015**
Current:		
Federal	$ 1,789	$ 27
State	164	(237)
Total current	1,953	(210)
Deferred:		
Federal	117	(6,330)
State	30	(108)
Total deferred	147	(6,438)
Total income tax provision (benefit)	$ 2,100	$ (6,648)

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(Thousands of dollars)	At December 31, 2016	2015
Deferred Tax Assets:		
Accrued liabilities	$ 550	$ 593
Allowance for doubtful accounts	152	188
Derivative Contracts	1,273	3
Alternative minimum tax credits	6,612	5,319
Net operating loss carry-forwards	586	575
Percentage depletion carry-forwards	3,025	3,751
Total deferred tax assets	12,198	10,429
Deferred Tax Liabilities:		
Basis differences relating to managed partnerships	6,211	6,238
Depletion and depreciation	43,487	41,290
Derivative contracts		250
Total deferred tax liabilities	49,698	47,778
Net non-current deferred income tax liabilities	$ 37,500	$ 37,349

The total provision for income taxes for the years ended December 31, 2016 and 2015 varies from the federal statutory tax rate as a result of the following:

(Thousands of dollars)	Year Ended December 31, 2016	2015
Expected tax expense (benefit)	$ 1,885	$ (6,607)
State income tax, net of federal benefit	194	(228)
Percentage depletion	(84)	(200)
IRS settlement	75	
Other, net	30	387
Total income tax provision (benefit)	$ 2,100	$ (6,648)

Deferred income taxes reflect the impact of temporary differences between the amount of assets and liabilities recognized for financial reporting purposes and such amounts recognized for tax purposes.

The Company is entitled to percentage depletion on certain of its wells, which is calculated without reference to the basis of the property. To the extent that such depletion exceeds a property s basis, it creates a permanent difference, which lowers the Company s effective rate.

The Company has $6.61 million in alternative minimum tax (AMT) credits which can be used to lower the regular tax liability to the tentative AMT amount in years where the tentative AMT amount is less. These credits do not expire.

The Company is allowed a credit against the Texas Franchise Tax based on net operating losses incurred in prior periods. The credits allowed are $89 thousand in the years 2017 through 2026. Any credits not utilized in a given year due to the allowable credit exceeding the tax liability may be carried forward. No credit may be carried forward past

2026. The value of the credit is calculated net of the federal income tax effect.

The Company paid $75 thousand in settlement of an audit of its 2014 federal income tax return.

The company has not recorded any provision for uncertain tax positions. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. The 2004, 2005, 2006, 2009 and 2014 federal income tax returns have been audited by the Internal Revenue Service. The 2013 and 2015 returns are

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currently open for examination by the IRS. Returns for unexamined earlier years may be examined and adjustments made to the amount of percentage depletion and AMT credit carryforwards flowing from those years into an open tax year, although in general no assessment of income tax may be made for those years on which the statute has closed. State returns for the years 2013, 2014 and 2015 remain open for examination by the relevant taxing authorities.

9. Segment Information and Major Customers

The Company operates in one industry oil and gas exploration, development, operation and servicing. The Company s oil and gas activities are entirely in the United States.

The Company sells its oil and gas production to a number of purchasers. Listed below are the percent of the Company s total oil and gas sales made to each of the customers whose purchases represented more than 10% of the Company s oil and gas sales in the year 2016.

Oil Purchasers:		Gas Purchasers:	
Plains All American Inc.	40.72%	Targa Pipeline Mid-Continent	34.18%
Infinity Hydrocarbons, LLC.	15.18%	Continuum Producer Services	11.87%

Although there are no long-term oil and gas purchasing agreements with these purchasers, the Company believes that they will continue to purchase its oil and gas products and, if not, could be replaced by other purchasers.

10. Financial Instruments

Fair Value Measurements:

Authoritative guidance on fair value measurements defines fair value, establishes a framework for measuring fair value and stipulates the related disclosure requirements. The Company follows a three-level hierarchy, prioritizing and defining the types of inputs used to measure fair value. The fair values of the Company s interest rate swaps, natural gas and crude oil price collars and swaps are designated as Level 3. The following fair value hierarchy table presents information about the Company s assets and liabilities measured at fair value on a recurring basis at December 31, 2016 and 2015:

December 31, 2016	**Quoted Prices in Active Markets For Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Balance at December 31, 2016**
(Thousands of dollars)				
Assets				
Commodity derivative contracts	$	$	$ 57	$ 57
Total assets	$	$	$ 57	$ 57
Liabilities				
Commodity derivative contracts	$	$	$ (3,639)	$ (3,639)

Total liabilities	$	$	$ (3,639)	$ (3,639)

December 31, 2015	**Quoted Prices in Active Markets For Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Balance at December 31, 2015**
(Thousands of dollars)				
Liabilities				
Interest rate derivative contracts	$	$	$ (7)	$ (7)
Total liabilities	$	$	$ (7)	$ (7)

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The derivative contracts were measured based on quotes from the Company s counterparties. Such quotes have been derived using valuation models that consider various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term as applicable. These estimates are verified using comparable NYMEX futures contracts or are compared to multiple quotes obtained from counterparties for reasonableness.

The significant unobservable inputs for Level 3 derivative contracts include basis differentials and volatility factors. An increase (decrease) in these unobservable inputs would result in an increase (decrease) in fair value, respectively. The Company does not have access to the specific assumptions used in its counterparties valuation models. Consequently, additional disclosures regarding significant Level 3 unobservable inputs were not provided.

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the years ended December 31, 2016 and 2015.

	Year Ended December 31,	
(Thousands of dollars)	**2016**	**2015**
Net (liabilities) assets at beginning of period	$ (7)	$ 16,757
Total realized and unrealized gains (losses):		
Included in earnings (a)	(3,604)	3,966
Included in other comprehensive income (loss)	7	137
Purchases, sales, issuances and settlements	22	(20,867)
Net liabilities at end of period	$ (3,582)	$ (7)

(a) Derivative instruments are reported in revenues as realized gain/loss and on a separately reported line item captioned unrealized gain/loss on derivative instruments, and interest rate swap instruments are reported as an increase or reduction to interest expense.

Derivative Instruments:

The Company is exposed to commodity price and interest rate risk, and management considers periodically the Company s exposure to cash flow variability resulting from the commodity price changes and interest rate fluctuations. Futures, swaps and options are used to manage the Company s exposure to commodity price risk inherent in the Company s oil and gas production operations. The Company does not apply hedge accounting to any of its commodity based derivatives. Both realized and unrealized gains and losses associated with commodity derivative instruments are recognized in earnings.

Interest rate swap derivatives continue to be treated as cash-flow hedges and are used to fix our floating interest rates on existing debt. The value of these interest rate swaps at December 31, 2016 and 2015 are located, if applicable, in accumulated other comprehensive loss, net of tax. Settlements of the swaps, which began in January 2014 and concluded in January 2016, are recognized within interest expense.

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The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2016 and 2015:

(Thousands of dollars)	**Balance Sheet Location**	**Fair Value 2016**	**Fair Value 2015**
Asset Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Natural gas commodity contracts	Derivative Contracts-long term	$ 57	$
Total		$ 57	$
Liability Derivatives:			
Derivatives designated as cash-flow hedging instruments:			
Interest rate swap contracts	Derivative liability short-term	$	$ (7)
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term	(1,065)	
Natural gas commodity contracts	Derivative liability short-term	(1,482)	
Natural gas commodity contracts	Derivative liability long-term	(463)	
Crude oil commodity contracts	Derivative liability long-term	(629)	
Total		$ (3,639)	$ (7)
Total derivative instruments		$ (3,582)	$ (7)

The following table sets forth the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2016 and 2015:

(Thousands of dollars)	**Location of gain/loss recognized in income**	**Amount of gain/loss recognized in income 2016**	**Amount of gain/loss recognized in income 2015**
Derivative designated as cash-flow hedge instruments:			
Interest rate swap contracts	Interest expense	$ (7)	$ (284)
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Unrealized (loss) gain on derivative instruments, net	(1,888)	(2,273)
Crude oil commodity contracts	Unrealized (loss) gain on derivative instruments, net	(1,694)	(14,628)
Natural gas commodity contracts	Realized gain (loss) on derivative instruments, net	20	3,017

Crude oil commodity contracts	Realized gain (loss) on derivative instruments, net	(36)	18,134
		$ (3,605)	$ 3,966

11. Related Party Transactions

The Company, as managing general partner or managing trustee, makes an annual offer to repurchase the interests of the partners and trust unit holders in certain of the Partnerships or Trusts. The Company purchased such interests in an amount totaling $224,000 during 2016 and $409,000 during 2015.

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Treasury stock purchases in any reported period may include shares from a related party, which may include members of the Company s Board of Directors. In 2016, the Company purchased 10,000 shares from a related party.

Receivables from related parties consist of reimbursable general and administrative costs, lease operating expenses and reimbursement for property development and related costs. These receivables are due from joint venture partners, which may include members of the Company s Board of Directors.

Payables owed to related parties primarily represent receipts collected by the Company as agent for the joint venture partners, which may include members of the Company s Board of Directors, for oil and gas sales net of expenses.

12. Restricted Cash and Cash Equivalents

Restricted cash and cash equivalents include $3.54 million and $3.51 million at December 31, 2016 and 2015, respectively, of cash primarily pertaining to oil and gas revenue payments. There were corresponding accounts payable recorded at December 31, 2016 and 2015 for these liabilities. Both the restricted cash and the accounts payable are classified as current on the accompanying consolidated balance sheets.

13. Salary Deferral Plan

The Company maintains a salary deferral plan (the Plan) in accordance with Internal Revenue Code Section 401(k), as amended. The Plan provides for matching contributions, of which $465,000 and $577,000 were made in 2016 and 2015, respectively.

14. Earnings per Share

Basic earnings per share are computed by dividing earnings available to common stockholders by the weighted average number of common shares outstanding during the period. Diluted earnings per share reflect per share amounts that would have resulted if dilutive potential common stock had been converted to common stock in gain periods. The following reconciles amounts reported in the financial statements:

	Year Ended December 31,					
	2016			2015		
	Net Loss (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount
Basic	$ 3,444	2,293,688	$ 1.50	$ (12,784)	2,312,810	$ (5.53)
Effect of dilutive securities:						
Options		751,563				
Diluted (a)	$ 3,444	3,045,251	$ 1.13	$ (12,784)	2,312,810	$ (5.53)

(a) The effect of the 767,500 outstanding stock options is antidilutive for the twelve months ended December 31, 2015 due to a net loss reported for the period.

15. Shareholder s Equity

The Company has in place a stock repurchase program whereby it may purchase outstanding shares of its common stock from time-to-time, in open market transactions or negotiated sales. The Company uses the cost method to account for its treasury share purchases.

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO

OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2016 and 2015

(Unaudited)

(Thousands of dollars)	**As of December 31, 2016**	**2015**
Proved Developed oil and gas properties	$ 417,824	$ 395,129
Proved Undeveloped oil and gas properties		
Total Capitalized Costs	417,824	395,129
Accumulated depreciation, depletion and valuation allowance	230,333	204,213
Net Capitalized Costs	$ 187,491	$ 190,916

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,

EXPLORATION AND DEVELOPMENT ACTIVITIES

Years Ended December 31, 2016 and 2015

(Unaudited)

(Thousands of dollars)	**Year Ended December 31, 2016**	**2015**
Development Costs	$ 19,042	$ 14,550

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2016 and 2015

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2016**	**2015**
Future cash inflows	$ 221,542	$ 293,745
Future production costs	(115,091)	(191,227)
Future development costs	(31,870)	(30,586)
Future income tax expenses	(7,883)	(4,815)
Future Net Cash Flows	66,698	67,117
10% annual discount for estimated timing of cash flows	(14,461)	(8,315)
Standardized Measure of Discounted Future Net Cash Flows	$ 52,237	$ 58,802

See accompanying Notes to Supplementary Information

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STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS AND CHANGES THEREIN

RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2016 and 2015

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2016 and 2015:

	Year Ended December 31,	
(Thousands of dollars)	**2016**	**2015**
Sales of oil and gas produced, net of production costs	$ (10,762)	$ (10,426)
Net changes in prices and production costs	(6,895)	(511,116)
Extensions, discoveries and improved recovery	27,706	24,967
Revisions of previous quantity estimates	(5,214)	(180,048)
Net change in development costs	(26,953)	235,285
Reserves sold		(1,160)
Reserves purchased		737
Accretion of discount	5,880	34,329
Net change in income taxes	(2,600)	146,339
Changes in production rates (timing) and other	12,273	(23,393)
Net change	(6,565)	(284,486)
Standardized measure of discounted future net cash flow:		
Beginning of year	58,802	343,288
End of year	$ 52,237	$ 58,802

See accompanying Notes to Supplementary Information

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION

Years Ended December 31, 2016 and 2015

(Unaudited)

	As of December 31,					
	2016			2015		
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	4,579	1,673	23,275	6,239	2,160	32,267
Extensions, discoveries and improved recovery	577	176	1,136	47	85	2,067
Revisions of previous estimates	(1,425)	(527)	(7,342)	(1,650)	(560)	(8,368)
Converted from undeveloped reserves	46	14	65	677	163	944
Reserves sold		(1)	(7)	(53)		(26)
Reserve purchased				39	12	372
Production	(670)	(70)	(4,126)	(720)	(187)	(3,981)
End of year	3,107	1,265	13,001	4,579	1,673	23,275
Proved Undeveloped Reserves:						
Beginning of year	52	12	55	14,709	4,322	26,331
Extensions, discoveries and improved recovery	635	157	1,994	420	101	701
Revisions of previous estimates	2	4	19	(14,400)	(4,248)	(26,033)
Converted to developed reserves	(46)	(14)	(65)	(677)	(163)	(944)
End of year	643	159	2,003	52	12	55
Total Proved Reserves at the End of the Year	3,750	1,424	15,004	4,631	1,685	23,330

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2016 and 2015

(Unaudited)

(Thousands of dollars)	Year Ended December 31, 2016	2015
Revenue:		
Oil and gas sales	$ 38,306	$ 45,632
Costs and Expenses:		
Lease operating expenses	27,544	35,206
Depreciation, depletion and accretion	27,534	28,531
Income tax (benefit) expense	(5,870)	(6,156)
Total Costs and Expenses	49,208	57,581
Results of Operations From Producing Activities (excluding corporate overhead and interest costs)	$ (10,902)	$ (11,949)

See accompanying Notes to Supplementary Information

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PRIMEENERGY CORPORATION AND SUBSIDIARIES

NOTES TO SUPPLEMENTARY INFORMATION

(Unaudited)

1. Presentation of Reserve Disclosure Information

Reserve disclosure information is presented in accordance with U.S. generally accepted accounting principles. The Company s reserves include amounts attributable to non-controlling interests in the Partnerships. These interests represent less than 10% of the Company s reserves.

2. Determination of Proved Reserves

The estimates of the Company s proved reserves were determined by an independent petroleum engineer in accordance with U.S. generally accepted accounting principles. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development and other factors. Estimated future net revenues were computed by reserves, less estimated future development and production costs based on current costs.

Proved reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that proved reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

3. Results of Operations from Oil and Gas Producing Activities

The results of operations from oil and gas producing activities were prepared in accordance with U.S. generally accepted accounting principles. General and administrative expenses, interest costs and other unrelated costs are not deducted in computing results of operations from oil and gas activities.

4. Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes of standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with U.S. generally accepted accounting principles.

Future cash inflows are computed as described in Note 2 by applying current prices to year-end quantities of proved reserves.

Future production and development costs are computed estimating the expenditures to be incurred in developing and producing the oil and gas reserves at year-end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying the year-end U.S. tax rate to future pre-tax cash inflows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences and tax credits and allowances relating to the proved oil and gas reserves.

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Future net cash flows are discounted at a rate of 10% annually (pursuant to applicable guidance) to derive the standardized measure of discounted future net cash flows. This calculation does not necessarily represent an estimate of fair market value or the present value of such cash flows since future prices and costs can vary substantially from year-end and the use of a 10% discount figure is arbitrary.

5. Changes in Reserves

The 2016 and 2015 extensions and discoveries reflect the successful drilling activity in the Company s West Texas and Mid-Continent areas. The Company is employing technologies to establish proved reserves that have been demonstrated to provide consistent results capable of repetition. The technologies and economic data being used in the estimation of its proved reserves include, but are not limited to, electrical logs, radioactivity logs, geologic maps, production data and well test data. The estimated reserves of wells with sufficient production history are estimated using appropriate decline curves. Estimated reserves of producing wells with limited production history and for undeveloped locations are estimated using performance data from analogous wells in the area. These wells are considered analogous based on production performance from the same formation and with similar completion techniques. Future development plans are reflective of the significant decrease in commodity prices and have been established based on an expectation of available cash flows from operations and availability under our revolving credit facility