

PRIMEENERGY CORP
Form 10-K
April 17, 2018
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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, 2017

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 (state or other jurisdiction of	84-0637348 (I.R.S. Employer
incorporation or organization)	Identification No.)
9821 Katy Freeway, Houston, Texas (Address of principal executive offices)	77024 (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 \$48,199,855.

The number of shares outstanding of each class of the Registrant's Common Stock as of April 13, 2018 was 2,097,777, 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 2018, 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 similar words are 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, 2017

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 and West Virginia. 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 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 six 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 primarily horizontal wells. We believe horizontal development of our resource base provides superior returns relative to vertical drilling by accessing a larger base of reserves in each target pay zone with a lateral wellbore.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2018, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2018 capital budget is reflective of current 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.

In accordance with SEC rules governing the scheduling of the drilling of PUD reserves we have only included in our year-end reserve report the 22 PUD locations for which we have definitive plans to drill. The Company has a working interest in eight of these PUD locations and an overriding royalty interest only in the remaining fourteen locations.

Since the start of our West Texas horizontal drilling program in 2015 the Company has participated in 56 horizontal wells in West Texas. In 39 of these wells, the Company owns an average of 22% working interest. All 39 wells are on production. As to 14 wells of the 56 total, the Company participated with less than 1% working interest. Of these 14 wells, seven are on line, and seven are drilled, fracture stimulated, and are being prepared to be put on production. During 2017, the Company expended approximately \$49.5 million in this program. Development of our West Texas resource has continued in the first quarter of 2018 with the drilling of three

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horizontal wells. As of March 31, 2018, these three wells have been drilled and are being prepared for hydraulic fracture stimulation. We also anticipate the drilling of an additional 8 wells in 2018, although AFEs and specific plans for drilling have not been finalized. This additional activity brings the anticipated total to 11 horizontal wells drilled in 2018 in our West Texas horizontal drilling program. In addition, the Company is participating for less than 1% interest in seven other horizontal wells that are in the process of being put on production.

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 year-end 2017, twenty-two wells have been drilled and completed in this joint venture. Sixteen of these were drilled and completed in 2017 at a gross cost of \$106,267,000. The Company invested a net \$43.3 million with an average 34.8% interest. In the first quarter of 2018, an additional three wells have been drilled and are in the process of being completed at an expected gross cost of \$25,441,000. We have a \$38.25 million interest in these wells and our expected net cost will be approximate \$9,371,000. Apache Corporation has indicated plans to continue to PAD drill the acreage and future phases of the development are expected to result in approximately 40 additional horizontal wells being drilled at a cost of about \$312 million. The Company owns 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 \$80 million. The actual number of wells drilled, the cost, and the timing of drilling may vary based upon commodity market conditions. Apache's drilling plans indicate an additional eight wells will be drilled later this year at a cost of \$50 million, of which our share is approximately \$24 million. These wells meet the definition of proved undeveloped reserves, however, they were not included in our year-end reserve report because we had not yet received AFEs and formal drilling plans.

In Martin County, Texas we are developing a 960 acre block with RSP Permian. In 2016, two wells were drilled and completed and two additional wells were drilled and brought on line in 2017. The Company owns approximately 35% to 38% interest in the acreage of this joint venture where RSP Permian is the operator. No near-term plans have been received from RSP Permian. During 2017, the Company spent approximately \$3 million on this development.

The Company maintains an acreage position of 20,443 gross (12,766 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 horizontal wells.

With regard to our Oklahoma horizontal development program, which began in 2012, the Company has participated in 28 horizontal wells for approximately \$27 million through year-end 2017. Over this same time period the Company chose to retain an overriding royalty interest in 28 other horizontal wells that were drilled. The Company is currently participating in two horizontal wells operated by Linn Operating Inc. in Grady County, Oklahoma. We are participating for 10% interest in one well and 1% interest in the other. The anticipated cost for these wells is \$14,703,000, with our net share being \$828,000. Both wells have been drilled and are waiting on fracture stimulation. In addition, the Company has elected to retain an ORRI in 16 wells that are in the process of being drilled or completed in various Counties of central Oklahoma. Also, in 2018, the Company anticipates participating in the drilling of as many as five additional horizontal wells in central Oklahoma with interest of between 6% and 12%. The horizontal activity on Company acreage in Oklahoma is primarily focused in Canadian, Grady, Kingfisher and Garvin counties where we have approximately 2,231 net acres. We believe our acreage has significant additional resource potential that could support the drilling of 72 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.

During March 2018 and effective January 1, 2018, PrimeEnergy agreed to sell its right, title and interest in 3,506 gross mineral acres, 1,600 net mineral acres, in Garfield County, Oklahoma, including 20 producing wells, for approximately \$1,600,000. The Company will retain an overriding royalty interest in the oil and gas produced from

the properties.

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In a separate transaction, which closed March 2018, the Company sold 10,600 gross mineral acres, 3,884 net mineral acres in Yuma County, Colorado, and Cheyenne County, Kansas, for \$175,000. This divestiture includes 54 producing wells.

In 2017, in the U.S. Gulf Coast region of Texas, the Company participated in the drilling of one well and the recompletion of two wells operated by Unit Petroleum in the Segno field of Polk County, Texas. The Company invested \$179,000 with a 2.8% working interest and a 3.77% revenue interest in these wells. All three wells were successful. In 2018, the Company plans to participate for 2.8% working interest in the recompletion of one well by Unit Petroleum, and has an overriding royalty of 3.87% in another well that is currently being drilled. The Company will also have an overriding royalty interest in an additional well slated to be drilled in the second quarter of 2018.

During the first quarter of 2018, the Company completed two transactions acquiring 464 net mineral acres, 53 oil and gas wells with working interests ranging from 16.6% to 33.4% and one commercial salt water disposal well operated by the Company, all located in Reagan County, Texas, for \$6,080,000.

Significant 2017 Activity

As of December 31, 2017, we had net capitalized costs related to proved oil and gas properties of \$213 million. Total expenditures for the acquisition, exploration and development of our properties during 2017 were \$59 million as we continue development under the programs discussed above. Proved reserves as of December 31, 2017, were 10.7 MMBOE which consisted of 93% proved developed reserves.

During 2017, we participated in drilling a total of 34 gross (5.9 net) wells; all of these wells are currently producing. This included 29 wells in our West Texas drilling program, four wells in our Mid-Continent region and one well in our Gulf Coast district.

During 2017 the Company also sold or farmed-out leasehold rights through six separate transactions, receiving gross proceeds of approximately \$46 million. In West Texas we sold approximately 2,096 net mineral acres for \$37.4 million, primarily located in Martin County, and in Oklahoma we farmed-out approximately 1,554 net mineral acres primarily in Canadian County for \$8.6 million and will retain an over-riding royalty interest and potential reversionary interests. These sales were of non-cash flowing mineral interests.

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, and West Virginia, 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.

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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 1496 wells, including SWD s injection and supply well, 298 through the Houston office, 373 through the Midland office, 348 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.

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 2017, we liquidated one of those partnerships, and today there are only 6 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 490.

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 ratatability 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

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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

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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 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

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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 prorating 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.

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;

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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.

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

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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.

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 of a 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

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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

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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.

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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.

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

The Company sells its oil and gas production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the percent of the Company's total oil and gas sales made which represented more than 10% of the Company's oil and gas sales in the year 2017.

Oil Purchasers:	
Apache Corporation	28%
Plains All American Inc.	23%
Sunoco, Inc.	16%
Shell Trading Company	10%
Gas Purchasers:	
Targa Pipeline Mid-Continent	25%
Apache Corporation	12%

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, 2018, we had 144 full-time employees, 45 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 99 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 \$2.98 per MMBTU in 2017 compared to \$2.49 per MMBTU in 2016, and have ranged from \$3.58 to \$2.61 per MMBTU for the first three months of 2018. Oil prices, based on the NYMEX monthly average price, were \$50.99 per barrel in 2017 compared to \$43.29 per barrel in 2016, and have increased to \$62.93 through March 2018. 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

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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 \$85 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 2018 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 2018 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, 2017, 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

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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

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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 (CO₂e)

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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 CO₂e 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.

Table of Contents***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 and EOWS Midland Company 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 Arnoldsburg, 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, 2017.

	2017		2016		2015	
	Gross	Net	Gross	Net	Gross	Net
Exploratory:						
Oil						
Gas						
Dry						
Development:						
Oil	26	6.3	27	3.6	8	3.6
Gas						
Dry						
Total:						
Oil	26	6.3	27	3.6	8	3.6
Gas						
Dry						
	26	6.3	27	3.6	8	3.6

Oil and Gas Production

As of December 31, 2017, 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	755	534
Gas Wells	821	537

⁽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, 2017. 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.

	2017	2016	2015
Oil (barrels)	1,004,000	670,000	720,000
Gas (Mcf)	5,008,000	4,546,000	4,696,000

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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, 2017.

	2017	2016	2015
Average sales price per barrel	\$ 49.70	\$ 39.73	\$ 70.93
Average sales price per Mcf	\$ 3.36	\$ 2.57	\$ 3.35
Average production costs per net equivalent barrel ⁽¹⁾	\$ 15.11	\$ 18.21	\$ 21.24

⁽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:

	2017	2016	2015
Oil Price per barrel	\$ 49.84	\$ 39.78	\$ 45.74
Gas Price per Mcf	\$ 3.36	\$ 2.56	\$ 2.71

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, 2017. 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	183,386	75,785	114	58	183,500	75,843
Mineral fee acreage	1,640	117	19,257	417	20,897	534
Total	185,026	75,902	19,371	475	204,397	76,377

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, 2017, is 0 acres for the year ending December 31, 2018, 58 in 2019 and 0 acres in 2020.

Reserves

Our interests in proved developed and undeveloped oil and gas properties, including the interests held by the Partnerships, have been evaluated by Ryder Scott Company, L.P. for each of the three years ended December 31, 2017. 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 Geologist. 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:

As of December 31,	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
	Oil (MMbbls)	NGLs (MMbbls)	Gas (MMcf)	Total (MBoe)	Oil (MMbbls)	NGLs (MMbbls)	Gas (MMcf)	Total (MBoe)	Oil (MMbbls)	NGLs (MMbbls)	Gas (MMcf)	Total (MBoe)
				(a)				(a)				(a)
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
2017	5,333	1,703	17,143	9,893	505	156	710	779	5,838	1,859	17,853	10,672

(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.

At December 31, 2015 we had undeveloped reserves of 73 MBoe, attributable to one well in our West Texas drilling program. This well was drilled in the first quarter of 2016 and the reserves converted to producing reserves.

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 overriding royalty interest in 14 horizontal wells drilled in Oklahoma by other operators. Included in our December 31, 2016, reserve report was 1,135 MBoe of proved undeveloped reserves attributable to 20 wells, 19 of which were horizontals. All 20 wells were drilled, completed and put on production in 2017 and 100% of their reserves converted to proved developed producing.

In 2017, the Company drilled, completed and put on production 22 horizontal wells in West Texas, three horizontal wells in Oklahoma, and one vertical well in Oklahoma. The company also increased reserves through overriding royalty interest in nine new wells. In the first quarter of 2018 the Company is actively participating for 38% interest in three horizontal wells in West Texas that are in the process of being drilled or completed. The estimated 8/8ths cost of these three wells will be approximately \$25.5 Million, of which the Company's share will be about \$9.7 Million. The Company is also participating in three wells in Oklahoma which are in various stages of being completed and placed on line. The estimated 8/8ths cost of these three wells is \$24.6 million, of which the Company's share will be about \$1.5 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, 2017, are summarized as follows (in thousands of dollars):

As of December 31,	Proved Developed		Proved Undeveloped		Total			
	Present Value 10 Of Future Net Revenue	Net Revenue	Present Value 10 Of Future Net Revenue	Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow	
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
2017	\$ 160,737	\$ 111,614	\$ 10,650	\$ 6,813	\$ 174,301	\$ 117,714	\$ 10,800	\$ 106,914

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 \$2.98 per MMBtu in 2017 as compared to \$2.49 per MMBtu in 2016. Oil prices, based on the NYMEX monthly average price, were \$50.99 per barrel in 2017 as compared to \$43.29 per barrel in 2016. Since January 1, 2018, 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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	Appalachian	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves at Year End (MBoe)						
Developed	537	803	1,774	6,742	37	9,893
Undeveloped			132	647		779
Total	537	803	1,906	7,389	37	10,672
Average Daily Production (Boe per day)	264	468	1,180	3,072	47	5,031
Gross Productive Wells	557	322	619	566	156	2,220
Net Productive Wells	456	174	256	515	24	1,425
Gross Operated Productive Wells	476	235	274	363	54	1,402
Gross Operated Water Disposal, Injection and Supply wells	1	8	64	7	1	81

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, 2017, we had interest in 557 wells (456 net), of which 476 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 2017 was 264 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, 2017, we had 537 MBoe of proved developed reserves (substantially all natural gas) in the Appalachian region, constituting 5% of our total proved reserves. We maintain an acreage position of over 40,200 gross (39,700 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, 2018 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, Wilcox,, San Miguel, Olmos, and Yegua formations at depths ranging from 3,000 to 12,500 feet. We had 310 producing wells (278 net) in the Gulf Coast region as of December 31, 2017, of which 243 wells are operated by us. Average daily production in 2017 was 468 Boe. At December 31, 2017, we had 784 MBoe of proved reserves in the Gulf Coast region, which represented 8% of our total proved reserves. We maintain an acreage position of over 12,640 gross (5,109 net) acres in this region, primarily in Dimmit and Polk counties. We operate a field service group in this region from a field office in Carrizo Springs, Texas utilizing four workover rigs, nineteen water

transport trucks, two saltwater disposal wells 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, 2018 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.

Table of Contents**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, 2017, we had 619 wells (256 net) in the Mid-Continent area, of which 274 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 2017 was 1180 Boe. At December 31, 2017, we had 1,906 MBoe of proved reserves in the Mid-Continent area, or 18% of our total proved reserves. We maintain an acreage position of over 78,494 gross (10,816 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 one 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, 2018, the Mid-Continent region is participating in the drilling and completion of one well included as Proved Behind-Pipe and one well included as Proved Undeveloped.

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, 2017, we had 566 wells (515 net) in the West Texas area, of which 363 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 2017 was 3,072 Boe. At December 31, 2017, we had 7,389 MBoe of proved reserves in the West Texas area, or 69% of our total proved reserves. We maintain an acreage position of over 20,443 gross (13,104 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 eight workover rigs, four hot oiler trucks and one 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, 2017 the Company had identified and committed to participate in three Proved Undeveloped horizontal drilling locations. As of March 31, 2018 all three of these wells have been drilled and are either on production or are in the process of being fracture stimulated.

Item 3. LEGAL PROCEEDINGS.

None.

Item 4. MINE SAFETY DISCLOSURES.

Not applicable.

Table of Contents**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
2017		
First Quarter	\$ 59.00	\$ 59.00
Second Quarter	50.05	49.50
Third Quarter	52.00	49.45
Fourth Quarter	55.00	52.00
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

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

As of March 27, 2018, there were 354 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.

Table of Contents**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 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, 2017, a total of 3,377,086 shares have been repurchased under this program for \$ 60,780,182 at an average price of \$18.00 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.

2017 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	101	\$ 54.05	236,946
February	140	57.25	236,806
March	251	49.55	236,555
April	85,033	49.98	155,522
May	2,242	41.12	149,280
June	5,057	46.80	144,223
July	1,274	48.31	142,949
August	49	47.39	142,900
September	7,060	47.02	135,840
October	339	49.99	135,501
November	10,445	50.03	125,056
December	2,142	51.50	122,914
Total / Average	114,133	\$ 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 and West Virginia. In addition, we own a substantial amount of well servicing equipment. All 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.

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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. 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 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 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

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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, 2017 was \$40.1 million, compared to \$11.0 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 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 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 2018, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2018 capital budget is reflective of 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.

The Company maintains a Credit Agreement with a maturity date of February 15, 2021, providing for a credit facility totaling \$300 million, with a borrowing base of \$85 million. As of March 31, 2018 the Company has \$62.5 million in outstanding borrowings and \$22.5 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 re-determined estimate of proved oil and gas reserves. The next borrowing base review is scheduled for June 2018. 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 re-determined 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, NGLs and natural gas.

	Volumes			Prices		
	2018	2019	2020	2018	2019	2020
Natural Gas (MMBTU)	2,400,000	749,000	180,000	\$ 2.97	\$ 2.93	\$ 2.95
Natural Gas Liquids (barrels)	66,000	60,000		\$ 22.73	\$ 21.66	
Oil (barrels)	214,800	540,500	100,500	\$ 51.95	\$ 53.53	\$ 56.11

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 primarily horizontal wells. We believe horizontal development of our resource base provides superior returns relative to vertical drilling by accessing a larger base of reserves in each target pay zone with a lateral wellbore.

In accordance with SEC rules governing the scheduling of the drilling of PUD reserves we have only included in our year-end reserve report the 22 PUD locations for which we have definitive plans to drill. The Company has a working interest in eight of these PUD locations and an overriding royalty interest only in the remaining fourteen locations.

Since the start of our West Texas horizontal drilling program in 2015 the Company has participated in 56 horizontal wells in West Texas. In 39 of these wells, the Company owns an average of 22% working interest. All 39 wells are on production. As to 14 wells of the 56 total, the Company participated with less than 1% working interest. Of these 14 wells, seven are on line, and seven are drilled, fracture stimulated, and are being prepared to be put on production. During 2017, the Company expended approximately \$49.5 million in this program. Development of our West Texas resource has continued in the first quarter of 2018 with the drilling of three horizontal wells. As of March 31, 2018, these three wells have been drilled and are being prepared for hydraulic fracture stimulation. We also anticipate the drilling of an additional 8 wells in 2018, although AFEs and specific plans for drilling have not been finalized. This additional activity brings the anticipated total to 11 horizontal wells drilled in 2018 in our West Texas horizontal drilling program. In addition, the Company is participating for less than 1% interest in seven other horizontal wells that are in the process of being put on production.

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 year-end 2017, twenty-two wells have been drilled and completed in this joint venture. Sixteen of these were drilled and completed in 2017 at a gross cost of \$106,267,000. The Company invested a net \$43.3 million with an average 34.8% interest. In the first quarter of 2018, an additional three wells have been drilled and are in the process of being completed at an expected gross cost of \$25,441,000. We have a 38.25% interest in these wells and our expected net cost will be approximate \$9,371,000. Apache Corporation has indicated plans to continue to PAD drill the acreage and future phases of the development are expected to result in approximately 40 additional horizontal wells being drilled at a cost of about \$312 million. The Company owns 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 \$80 million. The actual number of wells drilled, the cost, and the timing of drilling may vary based upon commodity market conditions. Apache's drilling plans indicate an additional eight wells will be drilled later this year at a cost of \$50 million, of which our share is approximately \$24 million. These wells meet the definition of proved undeveloped reserves, however, they were not included in our year-end reserve report because we had not yet received AFEs and formal drilling plans.

In Martin County, Texas we are developing a 960 acre block with RSP Permian. In 2016, two wells were drilled and completed and two additional wells were drilled and brought on line in 2017. The Company owns approximately 35% to 38% interest in the acreage of this joint venture where RSP Permian is the operator. No

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near-term plans have been received from RSP Permian. During 2017, the Company spent approximately \$3 million on this development.

The Company maintains an acreage position of 20,443 gross (12,766 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 horizontal wells.

With regard to our Oklahoma horizontal development program, which began in 2012, the Company has participated in 28 horizontal wells for approximately \$27 million through year-end 2017. Over this same time period the Company chose to retain an overriding royalty interest in 28 other horizontal wells that were drilled. The Company is currently participating in two horizontal wells operated by Linn Operating Inc. in Grady County, Oklahoma. We are participating for 10% interest in one well and 1% interest in the other. The anticipated cost for these wells is \$14,703,000, with our net share being \$828,000. Both wells have been drilled and are waiting on fracture stimulation. In addition, the Company has elected to retain an ORRI in 16 wells that are in the process of being drilled or completed in various Counties of central Oklahoma. Also, in 2018, the Company anticipates participating in the drilling of as many as five additional horizontal wells in central Oklahoma with interest of between 6% and 12%. The horizontal activity on Company acreage in Oklahoma is primarily focused in Canadian, Grady, Kingfisher and Garvin counties where we have approximately 2,231 net acres. We believe our acreage has significant additional resource potential that could support the drilling of 72 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.

During March 2018 and effective January 1, 2018, PrimeEnergy agreed to sell its right, title and interest in 3,506 gross mineral acres, 16,000 net mineral acres, in Garfield County, Oklahoma, including 20 producing wells, for approximately \$1,600,000. The Company will retain an overriding royalty interest in the oil and gas produced from the properties.

In a separate transaction, which closed March 2018, the Company sold 3,884 gross mineral acres, net mineral acres in Yuma County, Colorado, and Cheyenne County, Kansas, for \$175,000. This divestiture includes 54 producing wells.

In 2017, in the U.S. Gulf Coast region of Texas, the Company participated in the drilling of one well and the recompletion of two wells operated by Unit Petroleum in the Segno field of Polk County, Texas. The Company invested \$179,000 with a 2.8% working interest and a 3.77% revenue interest in these wells. All three wells were successful. In 2018, the Company plans to participate for 2.8% working interest in the recompletion of one well by Unit Petroleum, and has an overriding royalty of 3.87% in another well that is currently being drilled. The Company will also have an overriding royalty interest in an additional well slated to be drilled in the second quarter of 2018.

During the first quarter of 2018, the Company completed two transactions acquiring 464 net mineral acres, 53 oil and gas wells with working interests ranging from 16.6% to 33.4% and one commercial salt water disposal well operated by the Company, all located in Reagan County, Texas, for \$6,080,000.

To supplement cash flow and finance our drilling program during 2017, the Company also sold or farmed-out leasehold rights through six separate transactions, receiving gross proceeds of approximately \$46 million. In West Texas we sold approximately 2,096 net mineral acres for \$37.4 million, primarily located in Martin County, and in Oklahoma we farmed-out approximately 1,554 net mineral acres primarily in Canadian County for \$8.6 million and will retain an over-riding royalty interest and potential reversionary interests. These sales were of non-cash flowing mineral interests.

As of March 2018, the Company has \$2.3 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.

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The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2017 was \$5.96 million. The Company expects continued spending under these programs in 2018.

Results of Operations:***2017 and 2016 Compared***

We reported net income for 2017 of \$42.0 million, or \$18.99 per share, compared to \$3.4 million or \$1.50 per share for 2016. This increase was due to increases in oil and gas production and sales compared to 2016 combined with gains related to the sale of acreage. The significant components of net income are discussed below.

Oil and gas sales increased \$28.6 million, or 74.6% to \$66.9 million for the year ended December 31, 2017 from \$38.3 million for the year ended December 31, 2016. 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 increased an average of \$10.06 per barrel, or 25.3% on crude oil and increased \$0.80 per Mcf, or 31.4% on natural gas during 2017 as compared to 2016.

Our crude oil production increased by 334,000 barrels, or 49.9% from 670,000 barrels for the year ended December 31, 2016 to 1,004,000 barrels for the year ended December 31, 2017. Our natural gas production increased by 462 MMcf, or 10.2% from 4,546 MMcf for the year ended December 31, 2016 to 5,008 MMcf for the year ended December 31, 2017. The increase 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, 2017 and 2016 (excluding realized gains and losses from derivatives).

	Year Ended December 31,		Increase	
	2017	2016	Amount	Percent
Barrels of Oil Produced	1,004,000	670,000	334,000	49.9%
Average Price Received (excluding the impact of derivatives)	\$ 49.84	\$ 39.78	\$ 10.06	25.3%
Oil Revenue (In 000 \$)	\$ 50,041	\$ 26,655	\$ 23,386	87.7%
Mcf of Gas Produced	5,008,000	4,546,000	462,000	10.2%
Average Price Received (excluding the impact of derivatives)	\$ 3.36	\$ 2.56	\$ 0.80	31.4%
Gas Revenue (In 000 \$)	\$ 16,842	\$ 11,651	\$ 5,191	44.6%
Total Oil & Gas Revenue (In 000 \$)	\$ 66,883	\$ 38,306	\$ 28,577	74.6%

Realized losses on derivative instruments, net include losses of \$0.15 million and \$0.01 million on the settlements of crude oil and natural gas derivatives, respectively for the year ended December 31, 2017. This item included losses of

\$0.04 million and gains of \$0.02 million on the settlements of crude oil and natural gas derivatives, respectively for the year ended December 31, 2016.

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

	Year Ended December 31,		Increase	
	2017	2016	Amount	Percent
Oil Price	\$ 49.70	\$ 39.73	\$ 9.97	25.1%
Gas Price	\$ 3.36	\$ 2.57	\$ 0.79	30.8%

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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. For the year ended December 31, 2017 we recognized unrealized losses of \$1.7 million associated with crude oil fixed swaps and gains of \$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 2017 and December 2017. For the year ended December 31, 2016, we recognized unrealized losses of \$1.7 million associated with crude oil fixed swaps and gains of \$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 and December 2016.

Field service income increased \$0.3 million, or 1.8% from \$15.4 million for the year ended December 31, 2016 to \$15.7 million for the year ended December 31, 2017. Rates on our workover rigs and hot oiler services stabilized during 2017 in response to the increased commodity prices and our SWD income increased reflecting increased utilization of the pipeline and capacity upgrades added during the past three years.

Lease operating expense increased \$3.3 million, or 12.1% to \$30.9 million for the year ended December 31, 2017 from \$27.5 million for the year ended December 31, 2016. This increase was due to slight cost increases from suppliers, additional lease operating expenses related to new properties and the production taxes related to our increased oil and gas revenues.

Field service expense decreased \$0.6 million, or 4.5% from \$12.5 million for the year ended December 31, 2016 to \$12.0 million for the year ended December 31, 2017. Field service expenses primarily consist of salaries and vehicle operating expenses which had been reduced during 2016 and 2017 in response to falling rates and utilization of our equipment services.

Depreciation, depletion, amortization and accretion on discounted liabilities increased \$5.9 million, or 19.5% from \$30.2 million for the year ended December 31, 2016 to \$36.1 million for the year ended December 31, 2017. The DD&A expense is primarily attributable to our properties in West Texas and Oklahoma, reflecting the increased cost basis and production from development in those areas.

General and administrative expense increased \$1.8 million, or 22.9% to \$9.6 million for the year ended December 31, 2017 from \$7.8 million for the year ended December 31, 2016 related to personnel costs, including salaries and employee related taxes and insurance.

Gain on sale and exchange of assets of \$41.3 million for the year ended December 31, 2017 and \$32.4 million for the year ended December 31, 2016 consists of sales of non-producing acreage and oil and gas interests and non-essential field service equipment.

Interest expense decreased \$1.2 million, or 34.1% from \$3.5 million for the year ended December 31, 2016 to \$2.3 million for the year ended December 31, 2017. This decrease relates to a decrease in average debt outstanding during 2017 as compared to 2016 combined with an increase in weighted average interest rates during the 2017 periods. The average interest rate paid on outstanding bank borrowings under its revolving credit facility during 2017 and 2016 were 5.21% and 3.93%, respectively. As of December 31, 2017 and 2016, the total outstanding borrowings under its revolving credit facility were \$47.7 million and \$63.0 million, respectively.

A tax benefit of \$7.8 million was recorded for the year ended December 31, 2017, versus a tax provision of \$2.1 million for the year ended December 31, 2016. The tax benefit was directly related to the effect of the Tax Cuts and

Jobs Act passed in 2017, based on the remeasurement of deferred tax assets and liabilities at the lower corporate tax rate.

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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 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, 2017, 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, 2017.

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

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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, 2017. 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, 2017.

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.

There have been no changes in our internal controls over financial reporting during the fourth fiscal quarter ended December 31, 2017 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 to the Company's Annual Meeting of Stockholders to be held in June, 2018, which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2017, 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, 2018, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2017, 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, 2018, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2017, 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, 2018, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2017, 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, 2018, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2017, 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 | <u>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).</u> |
| 3.2 | <u>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).</u> |
| 10.18 | <u>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).</u> |
| 10.22.5.10 | <u>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 (Incorporated by reference to Exhibit 10.22.5.10 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2016).</u> |
| 10.22.5.10.1 | <u>FIRST AMENDMENT TO THIRD AMENDED AND RESTATED CREDIT AGREEMENT dated as of December 22, 2017 among PRIMEENERGY CORPORATION, as Borrower, THE LENDERS PARTY HERETO, COMPASS BANK, as Administrative Agent, WELLS FARGO BANK, NATIONAL ASSOCIATION, as Documentation Agent, and BBVA COMPASS, as Sole Lead Arranger and Sole Book Runner, (filed herewith).</u> |
| 10.22.5.11 | <u>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 (Incorporated by reference to Exhibit 10.22.5.11 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2016).</u> |

- 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 (Incorporated by reference to Exhibit 10.22.5.12 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2016).
- 10.22.5.13 Amended, Restated and Consolidated Deed of Trust, Mortgage, Security Agreement, Assignment of Production and Financing Statement Dated as of May 5, 2017 (Incorporated by reference to Exhibit 10.22.5.13 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2017).

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- 10.22.5.14 Deed of Trust, Mortgage, Security Agreement, Assignment of Production and Financing Statement Dated as of May 5, 2017 (Incorporated by reference to Exhibit 10.22.5.14 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2017).
- 10.22.5.15 Amended, Restated and Consolidated Mortgage of Oil and Gas Property, Security Agreement, Assignment of Production and Financing Statement Dated as of May 5, 2017 (Incorporated by reference to Exhibit 10.22.5.15 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2017).
- 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).
- 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 (Incorporated by reference to Exhibit 10.25 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2016).
- 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	<u>Subsidiaries (filed herewith).</u>
23	<u>Consent of Ryder Scott Company, L.P. (filed herewith).</u>

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Exhibit No.

31.1	<u>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).</u>
31.2	<u>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).</u>
32.1	<u>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).</u>
32.2	<u>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).</u>
99.1	<u>Summary Reserve Report dated February 12, 2018, of Ryder Scott Company, L.P. (filed herewith).</u>
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, 2018.

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, 2018.

/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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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors and Stockholders of

PrimeEnergy Corporation and Subsidiaries:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PrimeEnergy Corporation and Subsidiaries (the Company) as of December 31, 2017 and 2016, the related consolidated statements of operations, comprehensive income, equity, and cash flows for each of the years then ended, and the related notes (collectively referred to as the financial statements). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017, in conformity with U.S. generally accepted accounting principles.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

GRASSI & CO., CPAs, P.C.

We have served as the Company's auditor since 1989.

New York, New York

April 16, 2018

Table of Contents**PRIMEENERGY CORPORATION AND SUBSIDIARIES****CONSOLIDATED BALANCE SHEET***(Thousands of dollars)*

	As of December 31,	
	2017	2016
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 8,438	\$ 10,111
Accounts receivable, net	16,961	7,400
Prepaid obligations	756	412
Other current assets	476	160
Total Current Assets	26,631	18,083
Property and Equipment		
Oil and gas properties at cost	476,570	417,821
Less: Accumulated depletion and depreciation	(263,569)	(230,331)
	213,001	187,490
Field and office equipment at cost	26,241	26,902
Less: Accumulated depreciation	(19,267)	(18,024)
	6,974	8,878
Total Property and Equipment, Net	219,975	196,368
Other Assets	159	203
Total Assets	\$ 246,765	\$ 214,654
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	\$ 24,615	\$ 11,965
Accrued liabilities	16,294	8,184
Current portion of long-term debt	2,378	2,949
Current portion of asset retirement and other long-term obligations	2,309	1,563
Derivative liability short-term	1,509	2,547
Due to Related Parties	65	
Total Current Liabilities	47,170	27,208
Long-Term Bank Debt	48,459	66,316
Asset Retirement Obligations	21,269	15,943
Derivative Liability Long-Term	1,913	1,092
Deferred Income Taxes	24,962	37,500

Other Long-Term Obligations	553	715
Total Liabilities	144,326	148,774
Commitments and Contingencies		
Equity		
Common stock, \$.10 par value; 2017 and 2016: Authorized: 4,000,000 shares, issued: 3,836,397 shares; outstanding 2017: 2,169,370 shares; 2016: 2,283,503 shares	383	383
Paid-in capital	8,729	8,313
Retained earnings	138,320	96,322
Accumulated other comprehensive loss, net		
Treasury stock, at cost; 2017: 1,667,027 shares; 2016: 1,552,894 shares	(52,123)	(46,473)
Total Stockholders' Equity - PrimeEnergy	95,309	58,545
Non-controlling interest	7,130	7,335
Total Equity	102,439	65,880
Total Liabilities and Equity	\$ 246,765	\$ 214,654

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

Table of Contents**PRIMEENERGY CORPORATION AND SUBSIDIARIES****CONSOLIDATED STATEMENT OF OPERATIONS***(Thousands of dollars, except per share amounts)*

	For the Year Ended December 31,	
	2017	2016
Revenues		
Oil and gas sales	\$ 66,883	\$ 38,306
Realized loss on derivative instruments, net	(155)	(16)
Field service income	15,704	15,432
Administrative overhead fees	6,158	6,567
Unrealized gain (loss) on derivative instruments	547	(3,582)
Other income	173	59
Total Revenues	89,310	56,766
Costs and Expenses		
Lease operating expense	30,880	27,544
Field service expense	11,990	12,549
Depreciation, depletion, amortization and accretion on discounted liabilities	36,068	30,174
General and administrative expense	9,646	7,849
Total Costs and Expenses	88,584	78,116
Gain on Sale and Exchange of Assets	41,258	32,378
Income from Operations	41,984	11,028
Other Income and Expenses		
Less: Interest expense	2,310	3,507
Add: Interest income	7	1
Income Before Provision (Benefit) for Income Taxes	39,681	7,522
Provision (Benefit) for Income Taxes	(7,753)	2,100
Net Income	47,434	5,422
Less: Net Income Attributable to Non-Controlling Interest	5,436	1,978
Net Income Attributable to PrimeEnergy	\$ 41,998	\$ 3,444
Basic Income Per Common Share	\$ 18.99	\$ 1.50
Diluted Income Per Common Share	\$ 14.18	\$ 1.13

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,	
	2017	2016
Net Income	\$ 47,434	\$ 5,422
Other Comprehensive Income, net of taxes:		
Changes in fair value of hedge positions, net of taxes of \$0 and \$(2), respectively		5
Total other comprehensive income		5
Comprehensive income	47,434	5,427
Less: Comprehensive income attributable to non-controlling interest	5,436	1,978
Comprehensive Income attributable to PrimeEnergy	\$ 41,998	\$ 3,449

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

Table of Contents**PRIMEENERGY CORPORATION AND SUBSIDIARIES****CONSOLIDATED STATEMENT OF EQUITY***(Thousands of dollars)*

	Common Stock		Accumulated Other Comprehensive			Treasury Stock	Total Stockholders' Non- Controlling		Total Equity
	Shares	Amount	Paid-In Capital	Earnings (Loss)	Income		Equity	Interest	
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
Purchase 114,133 shares of common stock						(5,650)	(5,650)		(5,650)
Net income				41,998			41,998	5,436	47,434
Purchase of non-controlling interest			416				416	(724)	(308)
Distributions to non-controlling interest								(4,917)	(4,917)
Balance at December 31, 2017	3,836,397	\$ 383	\$ 8,729	\$ 138,320	\$	\$ (52,123)	\$ 95,309	\$ 7,130	\$ 102,439

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

Table of Contents**PRIMEENERGY CORPORATION AND SUBSIDIARIES****CONSOLIDATED STATEMENT OF CASH FLOWS***(Thousands of dollars)*

	For the Year Ended December 31,	
	2017	2016
Cash Flows from Operating Activities:		
Net Income	\$ 47,434	\$ 5,422
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	36,068	30,174
Gain on sale of properties	(41,258)	(32,378)
Unrealized (gain) loss on derivative instruments	(547)	3,582
(Benefit) Provision for deferred income taxes	(12,538)	147
Changes in assets and liabilities:		
(Increase) Decrease in accounts receivable	(9,561)	2,143
Increase (Decrease) in due from related parties	101	(25)
(Increase) Decrease in inventories	(9)	61
(Increase) Decrease in prepaid expenses and other assets	(344)	207
Increase (Decrease) in accounts payable	12,650	(390)
Increase in accrued liabilities	8,111	2,062
Net Cash Provided by Operating Activities	40,107	11,005
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(59,361)	(20,843)
Proceeds from sale of properties and equipment	46,231	35,226
Net Cash (Used in) Provided by Investing Activities	(13,130)	14,383
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(5,650)	(1,093)
Purchase of non-controlling interests	(308)	(224)
Increase in long-term bank debt and other long-term obligations	64,853	13,500
Repayment of long-term bank debt and other long-term obligations	(82,628)	(39,910)
Distribution to non-controlling interest	(4,917)	(843)
Net Cash Used in Financing Activities	(28,650)	(28,570)
Net Decrease in Cash and Cash Equivalents	(1,673)	(3,182)
Cash and Cash Equivalents at the Beginning of the Year	10,111	13,293
Cash and Cash Equivalents at the End of the Year	\$ 8,438	\$ 10,111

Supplemental Disclosures:

Income taxes paid during the year	\$ 414	\$ 120
Interest paid during the year	\$ 2,339	\$ 3,476

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

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Table of Contents**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, primarily in Oklahoma, Texas and West Virginia. The Company operates over approximately 1,500 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) and EOWS Midland Company (EMID) 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. PrimeEnergy Management Corporation (PEMC), a wholly-owned subsidiary, acts as the managing general partner, providing administration, accounting and tax preparation services for 6 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.

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 2 to these financial statements.

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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 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.

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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 asset retirement obligation primarily represents the estimated present value of the amount the Company will incur to plug, abandon and remediate producing properties 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, 2017, and 2016, 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.

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Table of Contents***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, 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:

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, *Extractives - Oil and Gas Revenue Recognition*. The new standard removes inconsistencies in existing standards, changes the way companies recognize revenue from contracts with customers, and increases disclosure requirements. The codification was amended through additional ASUs and, as amended, requires companies to recognize revenue to depict the transfer of goods or services to customers in amounts that reflect the consideration to which the company expects to be entitled in exchange for those goods or services. The guidance is effective for annual and interim periods beginning after December 15, 2017. The Company adopted the new standard on January 1, 2018, utilizing the modified retrospective approach. Adoption of this ASU did not have a material impact on net earnings. Certain items netted in revenue prior to adoption are recorded to expense based on the requirements of the new ASU. The Company developed an accounting policy, implemented changes to the relevant business processes and the control activities within them, and continues to evaluate the disclosure requirements as a result of the provisions of this ASU.

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.

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

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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.

In January 2017, the FASB issued ASU No. 2017-03, Accounting Changes and Error Corrections (Topic 250) and Investments - Equity Method and Joint Venture (Topic 323), which states that registrants should consider additional qualitative disclosures if the impact of an issued but not yet adopted ASU is unknown or cannot be reasonably estimated and to include a description of the effect of the accounting policies that the registrant expects to apply, if determined. Transition guidance in certain issued but not yet adopted ASUs, including Leases and Revenue Recognition, was also updated to reflect this amendment. This guidance is effective immediately. The adoption of this guidance had no effect on the Company's financial statements.

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 \$308,000 in 2017 and \$224,000 in 2016.

In May of 2017, we acquired 118 net mineral acres in one and a half sections in Upton County, Texas for \$596,600 directly offsetting Company acreage. This purchase increased Prime's leasehold in a core area of expected future development. During the first quarter of 2018, the Company acquired 1,640 gross (464 net) mineral acres, along with 16.6% to 33.4% working interest ownership in 53 oil and gas wells and one commercial salt water disposal well operated by the Company, all located in Reagan County, Texas, for \$6,080,000.

During 2017 the Company also sold or farmed-out leasehold rights through six separate transactions, receiving gross proceeds of approximately \$46 million. In West Texas we sold approximately 2,096 net mineral acres for \$37.4 million, primarily located in Martin County, and in Oklahoma we farmed-out approximately 1,554 net mineral acres primarily in Canadian County for \$8.6 million and will retain an over-riding royalty interest and potential reversionary interests. These sales were of non-cash flowing mineral interests.

The Company has entered into agreements and closed on the sale of additional non-core acreage and properties for proceeds of approximately \$1.8 million during the first quarter of 2018.

During 2016, the Company 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 were \$34.4 million.

3. Additional Balance Sheet Information

Accounts receivable at December 31, 2017 and 2016 consisted of the following:

<i>(Thousands of dollars)</i>	December 31,	
	2017	2016
Joint interest billings	\$ 3,173	\$ 2,345
Trade receivables	941	1,070

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Oil and gas sales	12,941	4,078
Other	4	204
	17,059	7,697
Less: Allowance for doubtful accounts	(98)	(297)
Total	\$ 16,961	\$ 7,400

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Accounts payable at December 31, 2017 and 2016 consisted of the following:

<i>(Thousands of dollars)</i>	December 31,	
	2017	2016
Trade	\$ 14,317	\$ 3,967
Royalty and other owners	7,073	5,909
Partner advances	1,268	592
Prepaid drilling deposits	67	83
Other	1,890	1,414
Total	\$ 24,615	\$ 11,965

Accrued liabilities at December 31, 2017 and 2016 consisted of the following:

<i>(Thousands of dollars)</i>	December 31,	
	2017	2016
Compensation and related expenses	\$ 2,449	\$ 2,295
Property costs	9,141	3,317
Income tax	4,180	1,988
Other	524	584
Total	\$ 16,294	\$ 8,184

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.

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 amended and restated by 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. The credit facility is secured by substantially all of the Company s oil and gas properties. 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.

On December 22, 2017, the Company and its lenders entered into a First Amendment to the Third Amended and Restated Credit Agreement. The credit agreement includes the addition of a new lender and retains all other aspects of the original credit agreement. As of the effective date of this amendment the Company's borrowing base was increased to \$85 million.

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At December 31, 2017, the Company had a total of \$47.7 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 5.21% and \$37.3 million available for future borrowings. The combined weighted average interest rate paid on outstanding bank borrowings subject to base rate and LIBO interest was 4.97% for the year ended December 31, 2017 as compared to 3.93% for year ended December 31, 2016. The Company's borrowings under this credit facility approximates fair value because the interest rates are variable and reflective of market rates.

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 related to the settlement of interest rate swaps for the twelve months ended December 31, 2016.

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 of December 31, 2017, the Company had a total of \$1.267 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 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, with a rate of 3.50% and requiring monthly payments (principal and interest) of \$8,700 with a final maturity date of June 26, 2020. As of December 31, 2017, the Company had a total of \$1.870 million outstanding on the Additional Equipment Loans.

On January 12, 2018, the Company made a principal payment towards the third interim loan in the amount of \$20,858. Effective with the payment due of January 26, 2018 the required monthly payments (principal and interest) on this loan changed to \$7,986 with a continuing effective rate of 3.50% and a final maturity of June 26, 2020.

The Company determined these loans are Level 3 liabilities in the fair-value hierarchy and estimated their fair value as \$3,110 million and \$6,147 million at December 31, 2017 and 2016, respectively, using a discounted cash flow model.

Table of Contents**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, 2017 are as follows.

<i>(Thousands of dollars)</i>	Operating Leases
2018	\$ 486
2019	172
Total minimum payments	\$ 658

Rent expense for office space for the years ended December 31, 2017 and 2016 was \$659,000 and \$892,000, respectively.

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2017 and 2016 is as follows:

<i>(Thousands of dollars)</i>	Year Ended December 31,	
	2017	2016
Asset retirement obligation at beginning of period	\$ 17,505	\$ 11,737
Liabilities incurred	45	68
Liabilities settled	(676)	(288)
Accretion expense	768	498
Revisions in estimated liabilities	5,936	5,490
 Asset retirement obligation at end of period	 \$ 23,578	 \$ 17,505

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 2017 revisions in estimated liabilities for asset retirement obligations resulted from increased field costs resulting in shorter productive life of marginal wells and the Company's acceleration of the schedule for plugging various marginal non-core properties.

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.

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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, 2017 and 2016, 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, 2017 and 2016 are as follows:

(Thousands of dollars)	Year Ended December 31,	
	2017	2016
Current:		
Federal	\$ 4,522	\$ 1,789
State	262	164
Total current	4,784	1,953
Deferred:		
Federal	(13,226)	117
State	689	30
Total deferred	(12,537)	147
Total income tax provision (benefit)	\$ (7,753)	\$ 2,100

(Thousands of dollars)	At December 31,	
	2017	2016
Deferred Tax Assets:		
Accrued liabilities	\$ 349	\$ 550
Allowance for doubtful accounts	22	152
Derivative Contracts	684	1,273
Alternative minimum tax credits	9,919	6,612
Net operating loss carry-forwards	528	586
Percentage depletion carry-forwards	727	3,025
Total deferred tax assets	12,229	12,198
Deferred Tax Liabilities:		
Basis differences relating to managed partnerships	3,193	6,211
Depletion and depreciation	33,998	43,487

Total deferred tax liabilities	37,191	49,698
Net deferred tax liabilities	\$ 24,962	\$ 37,500

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The total provision for income taxes for the years ended December 31, 2017 and 2016 varies from the federal statutory tax rate as a result of the following:

<i>(Thousands of dollars)</i>	Year Ended December 31,	
	2017	2016
Expected tax expense	\$ 11,643	\$ 1,885
Revaluation of deferred tax attributes	(20,204)	
State income tax, net of federal benefit	717	194
Percentage depletion	(89)	(84)
IRS settlement		75
Other, net	180	30
Total income tax provision (benefit)	\$ (7,753)	\$ 2,100

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.

On December 22, 2017, the U.S. enacted into law the Tax Cuts and Jobs Act (2017 Tax Act). For the year ended December 31, 2017, the Company recorded a tax benefit of \$20.204 million directly related to the effect of the 2017 Tax Act, based on the remeasurement of deferred tax assets and liabilities at the lower corporate tax rate.

The Company has \$9.918 million in alternative minimum tax (AMT) credits at December 31, 2017. Under the 2017 Tax Act, the Company may fully offset any regular tax liability in future years. In addition, a portion of the minimum tax credit which exceeds the regular tax liability is refundable in future years. The refundable portion is 50% of any excess credit in the years 2018 through 2020 and 100% in 2021. The Company will therefore expect to receive credits against regular tax and refunds of previously paid taxes in the amount of \$9.918 million over the next four years.

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 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 2018 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.

In 2016, 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 2015 through 2017 returns are 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 2014 through 2017 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.

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The Company sells its oil and gas production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the percent of the Company's total oil and gas sales made which represented more than 10% of the Company's oil and gas sales in the year 2017.

Oil Purchasers:	
Apache Corporation	28%
Plains All American Inc.	23%
Sunoco, Inc.	16%
Shell Trading Company	10%
Gas Purchasers:	
Targa Pipeline Mid-Continent	25%
Apache Corporation	12%

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, 2017 and 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, 2017
December 31, 2017 <i>(Thousands of dollars)</i>				
Assets				
Commodity derivative contracts	\$	\$	\$ 388	\$ 388
Total assets	\$	\$	\$ 388	\$ 388
Liabilities				
Commodity derivative contracts	\$	\$	\$ (3,422)	\$ (3,422)
Total liabilities	\$	\$	\$ (3,422)	\$ (3,422)

December 31, 2016 <i>(Thousands of dollars)</i>	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
Assets				
Commodity derivative contracts	\$	\$	\$ 57	\$ 57
Total assets	\$	\$	\$ 57	\$ 57
Liabilities				
Commodity derivative contract	\$	\$	\$ (3,639)	\$ (3,639)
Total liabilities	\$	\$	\$ (3,639)	\$ (3,639)

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

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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 year ended December 2017.

(Thousands of dollars)

Net Liabilities	December 31, 2016	\$ (3,582)
Total realized and unrealized (gains) losses:		
Included in earnings (a)		392
Purchases, sales, issuances and settlements		156
Net Liabilities	December 31, 2017	\$ (3,034)

- (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.

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 are treated as cash-flow hedges and are used to fix our floating interest rates on existing debt. Settlements of the swaps, which began in January 2014 and concluded in January 2016, was recognized within interest expense. There were no remaining interest rate swaps as of December 31, 2017 and December 31, 2016. The value of interest rate swaps if applicable, would be recorded in accumulated other comprehensive loss, net of tax.

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The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2017 and 2016:

<i>(Thousands of dollars)</i>	Balance Sheet Location	Fair Value	
		December 31, 2017	December 31, 2016
Asset Derivatives:			
<i>Derivatives not designated as cash-flow hedging instruments:</i>			
Natural gas commodity contracts	Other Current Assets	\$ 344	\$ 57
Natural gas commodity contracts	Other Assets	44	57
Total		\$ 388	\$ 57
Liability Derivatives:			
<i>Derivatives not designated as cash-flow hedging instruments:</i>			
Crude oil commodity contracts	Derivative liability short-term	(1,504)	(1,065)
Natural gas commodity contracts	Derivative liability short-term	(4)	(1,482)
Natural gas commodity contracts	Derivative liability long-term	(4)	(463)
Crude oil commodity contracts	Derivative liability long-term	(1,910)	(629)
Total		\$ (3,422)	\$ (3,639)
Total derivative instruments		\$ (3,034)	\$ (3,582)

The following table sets forth the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2017 and 2016:

<i>(Thousands of dollars)</i>	Location of gain/loss recognized in income	Amount of gain/loss recognized in income	
		2017	2016
<i>Derivative designated as cash-flow hedge instruments:</i>			
Interest rate swap contracts	Interest expense	\$	\$ (7)
<i>Derivatives not designated as cash-flow hedge instruments:</i>			
Natural gas commodity contracts	Unrealized gain (loss) on derivative instruments, net	2,267	(1,888)
Crude oil commodity contracts	Unrealized (loss) gain on derivative instruments, net	(1,720)	(1,694)
Natural gas commodity contracts	Realized (loss) gain on derivative instruments, net	(9)	20

Crude oil commodity contracts	Realized loss on derivative instruments, net	(146)	(36)
		\$ 392	\$ (3,605)

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 \$308,000 during 2017 and \$224,000 during 2016.

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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 2017 and 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. 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 \$374,000 and \$465,000 were made in 2017 and 2016, respectively.

13. 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,					
	2017			2016		
	Net Income	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income	Weighted Average Number of Shares Outstanding	Per Share Amount
	(In 000 s)			(In 000 s)		
Basic	\$ 41,998	2,211,985	\$ 18.99	\$ 3,444	2,293,688	\$ 1.50
Effect of dilutive securities:						
Options		750,803			751,563	
Diluted (a)	\$ 41,998	2,962,788	\$ 14.18	\$ 3,444	3,045,251	\$ 1.13

14. 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.

Table of Contents**PRIMEENERGY CORPORATION AND SUBSIDIARIES****SUPPLEMENTARY INFORMATION****CAPITALIZED COSTS RELATING TO
OIL AND GAS PRODUCING ACTIVITIES****Years Ended December 31, 2017 and 2016****(Unaudited)**

<i>(Thousands of dollars)</i>	As of December 31,	
	2017	2016
Proved Developed oil and gas properties	\$ 476,570	\$ 417,824
Proved Undeveloped oil and gas properties		
Total Capitalized Costs	476,570	417,824
Accumulated depreciation, depletion and valuation allowance	263,569	230,333
Net Capitalized Costs	\$ 213,001	\$ 187,491

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,**EXPLORATION AND DEVELOPMENT ACTIVITIES****Years Ended December 31, 2017 and 2016****(Unaudited)**

<i>(Thousands of dollars)</i>	Year Ended December 31,	
	2017	2016
Development Costs	\$ 59,361	\$ 20,843

STANDARDIZED MEASURE OF DISCOUNTED FUTURE**NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES****Years Ended December 31, 2017 and 2016****(Unaudited)**

<i>(Thousands of dollars)</i>	As of December 31,	
	2017	2016
Future cash inflows	\$ 384,198	\$ 221,542
Future production costs	(175,099)	(115,091)
Future development costs	(34,798)	(31,870)
Future income tax expenses	(20,884)	(7,883)
Future Net Cash Flows	153,417	66,698
10% annual discount for estimated timing of cash flows	(46,503)	(14,461)
Standardized Measure of Discounted Future Net Cash Flows	\$ 106,914	\$ 52,237

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, 2017 and 2016
(Unaudited)**

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2017 and 2016:

<i>(Thousands of dollars)</i>	Year Ended December 31,	
	2017	2016
Sales of oil and gas produced, net of production costs	\$ (36,003)	\$ (10,762)
Net changes in prices and production costs	12,432	(6,895)
Extensions, discoveries and improved recovery	76,694	27,706
Revisions of previous quantity estimates	19,808	(5,214)
Net change in development costs	(5,199)	(26,953)
Reserves sold	(21)	
Reserves purchased	1,372	
Accretion of discount	5,224	5,880
Net change in income taxes	(13,001)	(2,600)
Changes in production rates (timing) and other	(6,628)	12,273
Net change	54,677	(6,565)
Standardized measure of discounted future net cash flow:		
Beginning of year	52,237	58,802
End of year	\$ 106,914	\$ 52,237

See accompanying Notes to Supplementary Information

Table of Contents**PRIMEENERGY CORPORATION AND SUBSIDIARIES****SUPPLEMENTARY INFORMATION****RESERVE QUANTITY INFORMATION****Years Ended December 31, 2017 and 2016****(Unaudited)**

	As of December 31,					
	Oil (MBbls)	2017 NGLs (MBbls)	Gas (MMcf)	Oil (MBbls)	2016 NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	3,107	1,265	13,001	4,579	1,673	23,275
Extensions, discoveries and improved recovery	2,263	488	3,253	577	176	1,136
Revisions of previous estimates	496	89	3,846	(1,425)	(527)	(7,342)
Converted from undeveloped reserves	383	103	476	46	14	65
Reserves sold	(2)		(13)		(1)	(7)
Reserve purchased	90	41	220			
Production	(1,004)	(282)	(3,640)	(670)	(70)	(4,126)
End of year	5,333	1,704	17,143	3,107	1,265	13,001
Proved Undeveloped Reserves:						
Beginning of year	643	159	2,003	52	12	55
Extensions, discoveries and improved recovery	298	118	335	635	157	1,994
Revisions of previous estimates	(53)	(18)	(1,153)	2	4	19
Converted to developed reserves	(383)	(103)	(476)	(46)	(14)	(65)
End of year	505	156	709	643	159	2,003
Total Proved Reserves at the End of the Year	5,838	1,860	17,852	3,750	1,424	15,004

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES**Years Ended December 31, 2017 and 2016**

(Unaudited)

<i>(Thousands of dollars)</i>	Year Ended December 31,	
	2017	2016
Revenue:		
Oil and gas sales	\$ 66,883	\$ 38,306
Costs and Expenses:		
Lease operating expenses	30,880	27,544
Depreciation, depletion and accretion	34,006	27,534
Income tax (benefit) expense	(7,753)	(5,870)
Total Costs and Expenses	57,133	49,208
Results of Operations from Producing Activities (excluding corporate overhead and interest costs)	\$ 9,750	\$ (10,902)

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 2018 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 2017 and 2016 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 current commodity prices and have been established based on an expectation of available cash flows from operations and availability under our revolving credit facility.