PRIMEENERGY RESOURCES CORP
Form 10-K
April 16, 2019
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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, 2018

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 Resources Corporation

(Exact name of registrant as specified in its charter)

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

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

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

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

Common Stock, par value $.10 per share

(Title of Class)

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

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

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

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

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

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

Large Accelerated Filer Accelerated Filer

Non-Accelerated Filer	Smaller Reporting Company
	Emerging growth company

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

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

The aggregate market value of the voting stock of the Registrant held by non-affiliates, computed by reference to the average bid and asked price of such common equity as of the last business day of the Registrant s most recently completed second fiscal quarter, was $68,389,117.

The number of shares outstanding of each class of the Registrant s Common Stock as of March 31, 2019 was 2,033,047 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 2019, are incorporated by reference in Part III hereof.

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FORWARD-LOOKING STATEMENTS AND RISK

This Annual Report on Form 10-K includes forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical facts included or incorporated by reference in this report, including, without limitation, statements regarding our future financial position, business strategy, budgets, projected revenues, projected costs and plans, and objectives of management for future operations, are forward-looking statements. Such forward-looking statements are based on our examination of historical operating trends, the information that was used to prepare our estimate of proved reserves as of December 31, 2018, and other data in our possession or available from third parties. In addition, forward-looking statements generally can be identified by the use of forward-looking terminology such as may, will, could, expect, intend, project, estimate, anticipate, plan, believe, c terminology. Although we believe that the expectations reflected in such forward-looking statements are reasonable, we can give no assurance that such expectations will prove to have been correct. Important factors that could cause actual results to differ materially from our expectations include, but are not limited to, our assumptions about:

- The market prices of oil, natural gas, NGLs, and other products or services,
- Our commodity hedging arrangements
- The supply and demand for oil, natural gas, NGLs, and other products or services
- Production and reserve levels;
- Drilling risks;
- Economic and competitive conditions;
- The availability of capital resources;
- Capital expenditure and other contractual obligations;
- Weather conditions
- Inflation rates;
- The availability of goods and services;

- Legislative, regulatory or policy changes;
- Terrorism or cyber attacks
- Occurrence of property acquisitions or divestitures;
- The integration of acquisitions;
- The securities or capital markets and related risks such as general credit, liquidity, market and interest-rate risks; and
- Other factors disclosed under Items 1 and 2 Business and Properties Estimated Proved Reserves and Future Net Cash Flows, Item 1A Risk Factors, Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, and elsewhere in this Form 10-K

All subsequent written and oral forward-looking statements attributable to the Company, or persons acting on its behalf, are expressly qualified in their entirety by the cautionary statements. Except as required by law, we assume no duty to update or revise our forward-looking statements based on changes in internal estimates or expectations or otherwise.

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PrimeEnergy Resources Corporation

FORM 10-K ANNUAL REPORT

For the Fiscal Year Ended

December 31, 2019

PART I

Item 1. BUSINESS.

General

PrimeEnergy Resources 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 three 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 the Company s extensive oil and gas reserves primarily through horizontal drilling. This strategy includes targeting reservoirs with high initial production rates and cash flow as well as other reservoirs with lower initial production rates but longer sustained rates and higher expected return on investment. We believe that with today s technology, horizontal development of our reserves provides superior economic results as compared to vertical development, by delivering higher production rates through greater contact and stimulation of a larger volume of reservoir rock while minimizing the surface footprint required to develop those same reserves.

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2019, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2019 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 development of proved undeveloped (PUD) reserves, our year-end reserve report includes only the eight PUD locations that at year-end were being drilled or completed. The Company has less than one percent interest in each of these eight wells. Also included in the reserve report are 20 wells that were drilled and completed in 2018, but were not on production at year-end and were therefore designated as shut-in. Of this group, the Company has a 49.5% working interest in eight wells drilled in Upton County, Texas, as part of our West Texas, horizontal development program, plus 10% to 12% working interest in six wells and minor royalty interest in an additional six wells, all of which were drilled in our Scoop-Stack development program in Oklahoma.

Since the start of our West Texas horizontal drilling program in 2015 and through the fourth quarter of 2018, the Company has participated in 67 horizontal wells in the Permian Basin: 56 of these were completed and

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producing by year-end 2018, and eight more are expected to be on-line by the end of the first quarter of 2019, and three will be put on production in the second quarter of 2019. Of the total 67 horizontal wells in this program, the Company has an average of 28.19% interest in 52 wells, and less than one percent interest in 15 wells. Of the 11 wells to be brought on production in 2019, the Company has 49% interest in 8 wells that are one-mile in length, as well as 46% interest in two wells and 5.3% interest in one well that are each two-miles in length. Through completion and first date of production we expect to have invested $32.2 million in these 11 wells, including production facilities.

In Upton County, West Texas, we are developing a contiguous 3,900 acre block with our joint venture partner, Apache Corporation. In this block the Company has 2,600 leasehold acres with interest between 14% and 56%, depending on the formation or depth being developed. In 2018, three horizontals were drilled, completed and brought on-line in this joint venture. An additional eight wells with one-mile long laterals in the Wolfcamp B were participated in for 49% interest and have been brought on production in February, 2019. Apache Corporation has indicated a desire to continue PAD drilling of this acreage in reservoirs above the Middle Wolfcamp that, as described below, are currently being tested in a nearby acreage block. If favorable results of these offset wells occur it is likely to spur the drilling of as many as 96 additional horizontal wells in the near future in this 3,900 acre block. The cost of such development would be approximately $748 million with the Company s share being approximately $284 million. The actual number of wells that will be drilled, the cost, and the timing of drilling will vary based upon many factors, including commodity market conditions.

Also in Upton County, Texas, the Company is developing a separate 1,310 acre block, with Apache Corporation as the operator. In the 4th quarter of 2018 three new horizontal wells, that were designated as probable, were drilled targeting pay intervals above the Middle Wolfcamp: one in the Wolfcamp A , one in the Jo Mill and one in the Lower Spraberry. These wells are expected to be placed into production in the second quarter of 2019 and will be important tests of the economic viability of these reservoirs for our acreage. Prime holds between 5% and 48% working interest in various depths of this acreage and our share of these three wells will be approximately $8.9 million. If favorable results are achieved from these three wells, an additional 21 locations are likely to be drilled in the near future at a gross cost of approximately $182 million with the Company s share being approximately $60 million.

In Martin County, Texas we are developing a 965 acre block with Concho Resources. In 2016, two horizontal wells were drilled and completed and two additional horizontals were drilled and brought on-line in 2017. The Company owns 35% to 38% interest in this joint venture acreage where Concho Resources is the operator. No near-term additional drilling plans have been received from Concho Resources, however, offset operators have been actively drilling and their results appear encouraging for the future development of multiple landing zones within this acreage block.

The fast pace of drilling in West Texas has subsided somewhat in the first quarter of 2019 due to lower NYMEX crude prices as well as a pipeline bottleneck that has constrained deliveries of West Texas crude to Cushing, Oklahoma. This bottle-neck has resulted in a greater price spread for West Texas Intermediate crude flowing to Cushing, Oklahoma. As additional pipeline capacity is completed in 2019 and early 2020, that spread is expected to narrow and drilling activity is expected to rebound.

In our Oklahoma Scoop-Stack horizontal development program, which began in 2012, the Company has participated in 45 horizontal wells for approximately $35 million through the fourth quarter of 2018 with an average interest of 13.8 %. Over this same time period, the Company chose to retain an overriding royalty interest in 51 other horizontal wells. In the fourth quarter of 2018, the Company participated for less than one percent interest in the drilling of four new wells at a net cost of $309,500. All of these are expected to be placed on-line in the first quarter of 2019. Our horizontal activity in Oklahoma is focused in Canadian, Grady, Kingfisher and Garvin counties where we have approximately 2,215 net acres. We believe this acreage has significant additional resource potential that could support the drilling of as many as 161 new horizontal wells based on an estimate of four to ten wells per section, depending on the reservoir target area, with our share of the capital expenditure being approximately $82 million at an average 10% ownership level.

In 2018, in the Gulf Coast region of Texas, Unit Petroleum drilled and completed two successful wells and recompleted a third well in the Wilcox Formation of the Jazz field in Polk County. The Company has a 3.87% overriding royalty interest in both of the newly drilled wells and a 2.8125% working interest and 3.769% revenue interest in the recompleted well. The Company s share of the recompletion expense was approximately $100,000. In addition, the Company successfully recompleted a shallow well in the Segno field of Polk County, Texas with a 72.5% working interest and a net expense of approximately $43,000.

Significant 2018 Activity

As of December 31, 2018, we had net capitalized costs related to proved oil and gas properties of $224 million. Total expenditures for the acquisition, exploration and development of our properties during 2018 were $46 million as we continue development under the programs discussed above. Proved reserves as of December 31, 2018, were 12.665 MMBOE which consisted of 99.7% proved developed reserves.

During 2018, we participated in a total of 28 gross (6.1 net) wells that were drilled and completed, 14 of these were producing at year-end, while the remaining 14 wells were shut-in at year-end and are all expected to be on production in the first quarter of 2019. Of the 28 total wells completed, 15 are in our West Texas horizontal drilling program, and 13 are in our Oklahoma Scoop-Stack horizontal development program.

In 2018, the Company sold or farmed-out leasehold rights through several transactions, receiving gross proceeds of approximately $3.1 million in exchange for leasehold interest in Oklahoma, Kansas, Colorado, Texas and Wyoming. This includes the sale of 1,808 net acres and 20 wells in Garfield County, Oklahoma, and 5,005 net acres along with 54 wells, in Yuma County, Colorado and Cheyenne County, Kansas.

In 2018, the Company acquired approximately 464 net acres and 16.6% to 33.4% working interest in 51 oil and gas wells and one commercial salt water disposal well, for a total cost of $6,080,000. This acreage and group of wells are operated by the Company and located in Reagan County, Texas, where future horizontal drilling will likely occur.

We believe that our diversified portfolio approach to our drilling activities produces more consistent and predictable economic results than would otherwise 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.

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

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

Well Operations

Our operations are conducted through our principal offices in Houston, Texas, and district offices in Houston and Midland, Texas, Oklahoma City, Oklahoma, and Charleston, West Virginia. We currently operate 1,368 wells, including producing, saltwater disposal, injection, and supply wells: 220 through the Houston office, 361 through the Midland office, 310 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 2018, we liquidated three of those partnerships, and today there are only 3 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 225.

Regulation

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by the United States Congress (Congress), state governments, the Federal Energy Regulatory Commission (the FERC) and other federal and state regulatory agencies and federal, state and local courts. We cannot predict when or whether any such proposals may become effective. We do not believe that such action or proposal would have a material disproportionate effect on us as compared to similarly situated competitors.

Regulation Affecting Production

As described above, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. In addition, all of the jurisdictions in which we own or

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operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. These laws and regulations may limit the number of oil and natural gas wells 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 NGLs within its jurisdiction. States do not regulate wellhead prices or engage in other similar direct regulation, but there can be no assurance that they will not do so in the future. The effect of such future regulations may be to limit the amounts of oil and natural gas that may be produced from our wells, negatively affect the economics of production from these wells or limit the number of locations we can drill.

The failure to comply with the rules and regulations of oil and natural gas production and related operations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of transportation and sale of gas.

The availability, terms and cost of transportation significantly affect sales of gas. Federal and state regulations govern the price and terms for access to gas pipeline transportation. Intrastate gas pipeline transportation activities are subject to various state laws and regulations, as well as orders of state regulatory bodies. The interstate transportation and sale of gas is subject to federal regulation, including regulation of the terms, conditions and rates for interstate transportation, storage and various other matters, primarily by the Federal Energy Regulatory Commission (FERC). FERC endeavors to make gas transportation more accessible to gas buyers and sellers on an open-access and non-discriminatory basis.

Pursuant to the Energy Policy Act of 2005 (EPAct 2005) it is unlawful for any entity, such as the Company, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of gas or transportation services subject to regulation by FERC, in contravention of rules prescribed by FERC. The EPAct 2005 also gives FERC authority to impose civil penalties of up to $1 million per day, subject to annual inflation adjustment, for each violation of the Natural Gas Act (NGA), the Natural Gas Policy Act of 1978 and related regulations.

Under FERC Order 704, which regulates annual gas transaction reporting requirements, any market participant, including a producer such as the Company, that engages in wholesale sales or purchases of gas that equal or exceed 2.2 million MMBtus of physical gas in the previous calendar year must annually report such sales and purchases to FERC on Form No. 552 by May 1 of the year following the calendar year when such sales and purchases occurred. Form No. 552 contains aggregate volumes of wholesale gas purchased or sold in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. Order 704 is intended to increase the transparency of the wholesale gas markets and to assist FERC in monitoring those markets and in detecting market manipulation.

Intrastate gas pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate gas pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate gas pipeline rates, vary from state to state. Additional proposals and proceedings that might affect the gas industry are considered from time to time by the U.S. Congress, FERC, state legislatures, state regulatory bodies and the courts. The Company cannot predict when or if any such proposals might become effective or their effect, if any, on its operations. The Company believes that the regulation of intrastate gas pipeline transportation

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rates will not affect its operations in any way that is materially different from the effects on its similarly situated competitors.

Regulation of transportation and sale of oil and NGL

Intrastate liquids pipeline transportation rates, terms and conditions are subject to regulation by numerous federal, state and local authorities and, in a number of instances, the ability to transport and sell such products on interstate pipelines is dependent on pipelines that are also subject to FERC jurisdiction under the Interstate Commerce Act (the ICA). The Company does not believe these regulations affect it any differently than other producers.

The ICA requires that pipelines maintain a tariff on file with the FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be just and reasonable. Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before the FERC.

Rates of interstate liquids pipelines are currently regulated by the FERC, primarily through an annual indexing methodology, under which pipelines increase or decrease their rates in accordance with an index adjustment specified by the FERC. For the five-year period beginning in July 2016, the FERC established an annual index adjustment equal to the change in the producer price index for finished goods plus 1.23 percent. This adjustment is subject to review every five years. Under the FERC s regulations, a liquids pipeline can request a rate increase that exceeds the rate obtained through application of the indexing methodology by using a cost-of-service approach, but only after the pipeline establishes that a substantial divergence exists between the actual costs experienced by the pipeline and the rates resulting from application of the indexing methodology. Increases in liquids transportation rates may result in lower revenue and cash flows for the Company.

In addition, due to common carrier regulatory obligations of liquids pipelines, capacity must be prorated among shippers in an equitable manner in the event there are nominations in excess of capacity by current shippers or capacity requests are received from a new shipper. Therefore, new shippers or increased volume by existing shippers may reduce the capacity available to the Company. Any prolonged interruption in the operation or curtailment of available capacity of the pipelines that the Company relies upon for liquids transportation could have a material adverse effect on its business, financial condition, results of operations and cash flows. However, the Company believes that access to liquids pipeline transportation services generally will be available to it to the same extent, if not better given the Company s firm transportation contracts, as to its similarly situated 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 million per violation per day, subject to annual inflation adjustment. The Commodity Futures Trading Commission (the CFTC) has also issued anti-manipulation rules that subject violators to a civil penalty of up to the greater of $1 million per violation, subject to annual inflation adjustment, or triple the monetary gain to the person for each violation.

Regulation of Environmental and Occupational Safety and Health Matters

Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment and occupational health and safety. These laws and regulations may, among other things: (i) require the acquisition of permits to conduct exploration, drilling and production operations; (ii) restrict the types, quantities and concentration of various substances that can be released into the environment or injected into formations in connection with oil and

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natural gas drilling and production activities; (iii) limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; (iv) require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells; and (v) impose substantial liabilities for pollution resulting from drilling and production operations. Any failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of corrective or remedial obligations and the issuance of orders enjoining performance of some or all of our operations.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental laws and regulations and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation has been to place more restrictions and limitations on activities that may affect the environment and thus any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transportation, disposal, or remediation requirements could have a material adverse effect on our financial position and results of operations. We may be unable to pass on such increased compliance costs to our purchasers. Moreover, accidental releases or spills may occur in the course of our operations and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While compliance with existing environmental laws and regulations has not had a material adverse effect on our operations to date, we can provide no assurance that this will continue in the future.

The following is a summary of the more significant existing and proposed environmental, occupational health and safety laws and regulations to which our business operations are or may be subject to and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

The Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act (RCRA), and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to rules issued by the U.S. Environmental Protection Agency (the EPA), individual state governments administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas drilling and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address the EPA s alleged failure to timely assess its RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and natural gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires the EPA to propose a rulemaking no later than March 15, 2019 for revision of certain Subtitle D criteria regulations pertaining to oil and natural gas wastes or to sign a determination that revision of the regulations is not necessary. EPA action in response to the consent decree remains pending. Removal of RCRA s exemption for exploration and production wastes has the potential to significantly increase our waste disposal costs to manage, which in turn will result in increased operating costs and could adversely impact our results of operations and financial position. Also, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the current and former owners and operators of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several 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. 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 substances released into the environment.

We generate materials in the course of our operations that may be regulated as hazardous substances. Despite the petroleum exclusion of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. In addition, we currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration, production and processing for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state and local laws. Under such laws, we could be required to undertake investigatory, response, or corrective measures, which could include soil and groundwater sampling, the removal of previously disposed substances and wastes, the cleanup of contaminated property, or remedial plugging or pit closure operations to prevent future contamination, the costs of which could be substantial.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act (the CWA), and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters, including wetland areas, is prohibited, except in accordance with the terms of a permit issued by the EPA, the U.S. Army Corps of Engineers (the USACE) or an analogous state agency. In September 2015, the EPA and the USACE issued a final rule redefining the scope of the EPA s and the USACE s jurisdiction under the CWA with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands (the WOTUS rule). Several legal challenges to the rule followed, along with attempts to stay implementation of the WOTUS rule following the change in U.S. presidential administrations. Currently, the WOTUS rule is active in 22 states and enjoined in 28 states. However, in December 2018, the EPA and the USACE proposed changes to regulations under the CWA that would provide discrete categories of jurisdictional waters and tests for determining whether a particular waterbody meets any of those classifications. Several groups have already announced their intent to challenge the proposed WOTUS replacement rule. Therefore, the scope of jurisdiction under the CWA is uncertain at this time. To the extent the original WOTUS rule or any replacement rule expands the scope of the CWA s jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. In addition, federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations. We do not expect the costs to comply with the requirements of the CWA to have a material adverse effect on our operations.

The Oil Pollution Act of 1990 amends the CWA and establishes strict liability for owners and operators of facilities that cause a release of oil into waters of the United States. In addition, this law requires owners and operators of facilities that store oil above specified threshold amounts to develop and implement spill prevention, control and countermeasures plans.

Safe Drinking Water Act and Saltwater Disposal Wells

In the course of our operations, we produce water in addition to oil and natural gas. Water that is not recycled or otherwise disposed of on the lease may be sent to saltwater disposal wells for injection into subsurface formations. Underground injection operations are regulated under the federal Safe Drinking Water Act and permitting and enforcement authority may be delegated to state governments. In Texas, the Texas Railroad Commission (RRC) regulates the disposal of produced water by injection well. The RRC requires operators to obtain a permit from the agency for the operation of saltwater disposal wells and establishes minimum standards for injection well operations. In response to recent seismic events near underground injection wells used for the disposal of oil and natural gas-related waste waters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or placed volumetric injection limits on existing wells or imposed moratoria on the use of such injection wells. In response to concerns related to induced seismicity, regulators in some states have already adopted or are considering additional requirements related to seismic safety. For example, the RRC has adopted rules for injection wells to address these seismic activity concerns in Texas. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. More stringent regulation of injection wells could lead to reduced construction or the capacity of such wells, which could in turn impact the availability of injection wells for disposal of wastewater from our operations. Increased costs associated with the transportation and disposal of produced water, including the cost of complying with regulations concerning produced water disposal, may reduce our profitability. The costs associated with the disposal of proposed water are commonly incurred by all oil and natural gas producers, however, and we do not believe that these costs will have a material adverse effect on our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as tank batteries and compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard for ozone from 75 to 70 parts per billion. The EPA approved final attainment/nonattainment designations with the new ozone standards in July 2018 and currently all of the areas in which we operate are in attainment with such standards. However, state implementation of these revised air quality standards or a change in the attainment status of the areas in which we operate could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. Separately, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements, which in turn could result in operational delays or require us to install costly pollution control equipment. The EPA has also adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as green completions. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. The EPA expanded on its emission standards for volatile organic compounds in June 2016 with the issuance of first-time standards, known as Subpart OOOOa, to address emissions of methane from equipment and processes across the oil and natural gas source category, including hydraulically fractured oil and natural gas well completions. Following the change in presidential administration, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result of these developments, substantial uncertainty exists with respect to implementation of the EPA s 2016 methane rule. However, given the long-term trend toward increasing regulation, future federal methane regulation of the oil and gas industry remains a possibility, and several states have separately imposed their own regulations on methane emissions from oil and gas production activities. These and other air pollution control and permitting requirements have the potential to delay the development of oil and natural gas projects and increase our costs of development and production, which costs could be significant. We do not believe that compliance with such requirements, however, will have a material adverse effect on our operations.

Regulation of Greenhouse Gas Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases (GHGs) endanger public health and the environment, the EPA has adopted regulations under existing provisions of the Clean Air Act that, among other things, establish Prevention of Significant Deterioration (PSD), construction and Title V operating permit reviews for certain large stationary sources. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards for these emissions. EPA rulemakings related to GHG emissions could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the annual reporting of GHG emissions from certain petroleum and natural gas system sources in the U.S., including, among others, onshore and offshore production facilities, which include certain of our operations. Also, as noted above, the EPA has promulgated a New Source Performance Standard related to methane emissions from the oil and natural gas source category.

While Congress has considered legislation related to the reduction of GHG emissions in the past, no significant legislation to reduce GHG emissions has been adopted at the federal level. In the absence of Congressional action, a number of state and regional GHG restrictions have emerged. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States adherence to the exit process is uncertain, and the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations.

Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades. However, recent activism directed at shifting funding away from companies with energy-related assets could result in limitations or restrictions on certain sources of funding for the energy sector. Finally, it

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should also be noted that many scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other climatic events; if any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves the injection of water, sand or alternative proppant and chemicals under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Recently, there has been increased public concern regarding an alleged potential for hydraulic fracturing to adversely affect drinking water supplies, resulting in new legislative and regulatory initiatives that seek to increase the regulatory burden imposed on hydraulic fracturing.

At the federal level, the EPA has asserted federal regulatory authority pursuant to the Safe Drinking Water Act over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities. Further, the EPA finalized regulations under the CWA in June 2016 that prohibit wastewater discharges from hydraulic fracturing and certain other natural gas operations to publicly owned wastewater treatment plants. Also, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that water cycle activities associated with hydraulic fracturing may impact drinking water resources under certain limited circumstances.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example in May 2013, the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of, or prohibiting, drilling or hydraulic fracturing activities. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we may be required to incur significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from drilling wells.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Endangered Species Act and Migratory Birds

The federal Endangered Species Act (ESA) and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species habitat. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service (the FWS) may designate critical habitat and suitable habitat areas that it believes are necessary for the survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a 2011 settlement agreement, the FWS was required to make a determination on listing of more than 250 species as endangered or threatened under the FSA by no later than completion of the agency s 2017 fiscal year. The FWS missed the deadline but reportedly continues to review new species for protected status under the ESA pursuant to the settlement agreement. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Recently, there have been renewed calls to review protections currently in place for the dunes sagebrush lizard, whose habitat includes portions of the Permian Basin, and to reconsider listing the species under the ESA. The designation as threatened or endangered of previously unprotected species in areas where we operate could cause us to incur increased costs arising from species protection measures or could result in limitations on our development and production activities that could have a material adverse impact on our ability to develop and produce our reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Administration (OSHA) and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation, or other oil and natural gas activities and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our exploration and production activities. However, this insurance is limited to activities at the well site, and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a material adverse effect on our financial condition and operations.

Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2018, nor do we anticipate that such expenditures will be material in 2019.

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 2018.

Oil Purchasers:	
Apache Corporation	50.9%
Plains All American Inc.	17.8%
Gas Purchasers:	
Apache Corporation	35.6%
Targa Pipeline Mid-Continent West Tex, LLC	21.4%

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 20, 2019, we had 156 full-time employees, 28 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 128 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 $3.10 per MMBTU in 2018 compared to $2.98 per MMBTU in 2017, and have ranged from $2.83 to $3.23 per MMBTU for the first three months of 2019. Oil prices, based on the NYMEX monthly average price, were $65.56 per barrel in 2018 compared to $51.34 per barrel in 2017, and first of the Month NYMEX oil prices have averaged $52.16 per barrel for the first three months of 2019. Any substantial or extended decline in future natural gas or crude oil prices would have, a material adverse effect on our future business, financial condition, results of operations, cash flows, liquidity or ability to finance planned capital expenditures and commitments. Furthermore, substantial, extended decreases in natural gas and crude oil prices may cause us to delay or postpone a significant portion of our exploration, development and exploitation projects or may render such projects uneconomic, which may result in significant downward adjustments to our estimated proved reserves and could negatively impact our ability to borrow and cost of capital and our ability to access capital markets, increase our costs under our revolving credit facility, and limit our ability to execute aspects of our business plans.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

The borrowing base under our revolving credit facility is currently $100 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 2019 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 2019 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.

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.

The Company s operations are subject to stringent environmental, oil and gas-related and occupational safety and health laws and regulations that could cause it to delay, curtail or cease its operations or expose it to material costs and liabilities.

The Company s operations are subject to stringent federal, state and local laws and regulations governing, among other things, the drilling of wells, rates of production, the size and shape of drilling and spacing units or proration units, the transportation and sale of oil, NGL and gas, and the discharging of materials into the environment and environmental protection. In connection with its operations, the Company must obtain and maintain numerous environmental and oil and gas-related permits, approvals and certificates from various federal, state and local governmental authorities, and may incur substantial costs in doing so. The need to obtain permits has the potential to delay, curtail or cease the development of oil and gas projects. Over the next several years, the Company may be charged royalties on gas emissions or required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in 2015, the EPA issued a final rule under the CAA lowering the National Ambient Air Quality Standard (NAAQS) for ground-level ozone from 75 parts per billion to 70 parts per billion under standards to provide protection of public health and welfare. In 2017 and 2018, the EPA issued area designations with respect to ground-level ozone as either attainment/unclassifiable, unclassifiable or non-attainment. Additionally, in November 2018, the EPA issued final requirements that apply to state, local and tribal air agencies for implementing the 2015 NAAQS for ground-level ozone. State implementation of the revised NAAQS could, among other things, require installation of new emission controls on some of the Company s equipment, resulting in longer permitting timelines, and significantly increase the Company s capital expenditures and operating costs. In another example, in 2016, the EPA published a final rule on the criteria for aggregating multiple surface sites into a single source for air-quality permitting purposes that is applicable to the oil and gas industry. This rule could cause small surface sites and the equipment at those sites to be aggregated for air emissions permitting purposes; however, in November 2018, the EPA published a final action that reinterprets source aggregation in a manner that could lessen the likelihood that air projects are aggregated for permitting. In a third example, the EPA and U.S. Army Corps of Engineers (the Corps) released a final rule in 2015 outlining federal jurisdictional reach under the CWA over waters of the U.S., including wetlands. Beginning in the first quarter of 2017, the EPA and the Corps agreed to reconsider the 2015 rule and, thereafter, the agencies have (i) published a proposed rule in July 2017 to rescind the 2015 rule and recodify the regulatory text that governed waters of the U.S. prior to promulgation of the 2015 rule, (ii) published a proposed rule in November 2017 and a final rule in February 2018 adding a February 6, 2020 applicable date to the 2015 rule, and (iii) announced a proposed rule on December 11, 2018, redefining the CWA s jurisdiction over waters of the U.S. for which the agencies will seek public comment. The 2015 and February 2018 final rules are being challenged by various factions in federal district court and implementation of the 2015 rule has been enjoined in 28 states pending resolution of the various federal district court challenges. As a result of these legal developments, future implementation of the 2015 rule or a revised rule is uncertain at this time. Future compliance with these legal requirements or with any new or amended environmental laws or regulations could, among other things, delay, restrict or prohibit the issuance of necessary permits, increase the Company s capital expenditures and operating expenses by, for example, requiring installation of new emission controls on some of the Company s equipment, any one or more of which developments could have a material adverse effect on the Company s business, financial condition and results of operations.

Additionally, the Company s operations are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act and comparable state statutes, whose purpose is to protect the health and safety of employees. Among other things, the Occupational Safety and Health Act hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in the Company s operations and that this information be provided to employees, state and local government authorities and citizens.

There can be no assurance that existing or future regulations will not result in a delay, curtailment or cessation of production or processing activities, result in a material increase in the costs of production, development, exploration or processing operations or materially and adversely affect the Company s future operations and financial condition. Noncompliance with these laws and regulations may subject the Company to sanctions, including administrative, civil or criminal penalties, remedial cleanups or corrective actions, delays in permitting or performance of projects, natural resource damages and other liabilities. Such laws and regulations may also affect the costs of acquisitions. In addition, these laws and regulations are subject to amendment or replacement in the future with more stringent legal requirements. Further, any delay, reduction or curtailment of the Company s development and producing operations due to these laws and regulations could result in the loss of acreage through lease expiration.

The nature of the Company s assets and production operations may impact the environment or cause environmental contamination, which could result in material liabilities to the Company.

The Company s assets and production operations may give rise to significant environmental costs and liabilities as a result of the Company s handling of petroleum hydrocarbons and wastes, because of air emissions and water discharges related to its operations, and due to past industry operations and waste disposal practices. The Company s oil and gas business involves the generation, handling, treatment, storage, transport and disposal of wastes, hazardous substances and petroleum hydrocarbons and is subject to environmental hazards, such as oil and produced water spills, NGL and gas leaks, pipeline and vessel ruptures and unauthorized discharges of such wastes, substances and hydrocarbons, that could expose the Company to substantial liability due to pollution and other environmental damage. For example, drilling fluids, produced waters and certain other wastes associated

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with the Company s exploration, development and production of oil or gas are currently excluded under RCRA from the definition of hazardous waste. These wastes are instead regulated under RCRA s less stringent non-hazardous waste provisions. There have been efforts from time to time to remove this exclusion, which removal could have a material adverse effect on the Company s results of operations and financial position. For example, in December 2016, the EPA entered into a settlement agreement with several non-governmental environmental groups in the U.S. District Court for the District of Columbia regarding the agency s alleged failure to timely assess its RCRA Subtitle D criteria regulations for oil and gas wastes. Under the terms of the settlement, the EPA is required to propose no later than March 15, 2019, a rulemaking for the revision of certain Subtitle D criteria regulations pertaining to oil and gas wastes or sign a determination that revision of the regulations is unnecessary. If the EPA proposes a rulemaking for revised oil and gas waste regulations, the settlement requires that the EPA take final action following notice and comment rulemaking no later than July 15, 2021.

The Company currently owns, leases or operates, and in the past has owned, leased or operated, properties that for many years have been used for oil and gas exploration and production activities, and petroleum hydrocarbons, hazardous substances and wastes may have been released on or under such properties, or on or under other locations, including off-site locations, where such substances have been taken for treatment or disposal. These wastes, substances and hydrocarbons may also be released during future operations. In addition, some of the Company s properties have been operated by predecessors or previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons were not under the Company s control. Joint and several strict liabilities may be incurred in connection with such releases of petroleum hydrocarbons, hazardous substances and wastes on, under or from the Company s properties. Private parties, including lessors of properties on which the Company operates and the owners or operators of properties adjacent to the Company s operations and facilities where the Company s petroleum hydrocarbons, hazardous substances or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as seek damages for noncompliance with environmental laws and regulations or for personal injury or damage to property or natural resources. Such properties and the substances disposed or released on or under them may be subject to CERCLA, RCRA and analogous state laws, which could require the Company to remove previously disposed substances, wastes and petroleum hydrocarbons, remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination, the costs of which could have a material adverse effect on the Company s business, financial condition and results of operations.

The Company may not be able to recover some or any of these costs from sources of contractual indemnity or insurance, as pollution and similar environmental risks generally are not insurable or fully insurable, either because such insurance is not available or because of the high premium costs and deductibles associated with obtaining such insurance.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil, NGLs and gas the Company produces, while the potential physical effects of climate change could disrupt the Company s production and cause it to incur significant costs in preparing for or responding to those effects.

Climate change continues to attract considerable public, political and scientific attention. As a result, numerous proposals have been made and are likely to continue to be made at the international, national, regional and state levels of government to monitor and limit emissions of GHGs. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG reporting and tracking programs, and regulations that directly limit GHG emissions from certain sources. In November 2018, the Trump Administration released the second volume of the fourth interagency National Climate Assessment that is issued pursuant to federal law. The current version outlines potentially severe climate-related impairments for the United States environment, economy and public health, which are indicated to worsen over time unless significant measures are taken to, among other things, reduce GHG emissions. This assessment could serve as a basis for increasing governmental pursuit of policies to restrict GHG emissions.

In the U.S., no comprehensive climate change legislation has been implemented at the federal level to date. In the absence of federal GHG-limiting legislation, the EPA has determined that GHG emissions present a danger to public health and the environment and has adopted rules under authority of the CAA that, among other things, establish certain permits and construction reviews designed to allow operations while ensuring the prevention of significant deterioration in air quality by GHG emissions from large stationary sources that are already potential sources of significant pollutant emissions. The Company could become subject to these permitting requirements and be required to install best available control technology to limit emissions of GHGs from any new or significantly modified facilities that the Company may seek to construct or modify in the future. The EPA has also adopted rules requiring the reporting of GHG emissions on an annual basis from specified GHG emission sources in the United States, including certain oil and gas production facilities, which include certain of the Company s facilities. Federal agencies also have begun directly regulating emissions of methane, a GHG, from oil and gas operations. In 2016, the EPA published a final rule establishing New Source Performance Standards, known as Subpart OOOOa, that require certain new, modified or reconstructed facilities in the oil and gas sector to reduce certain methane gas and volatile organic compound emissions. These Subpart OOOOa standards expand previously issued New Source Performance Standards, published by the EPA in 2012 and known as Subpart OOOO, by using certain equipment-specific emissions control practices. However, in June 2017, the EPA published a proposed rule to stay certain portions of these Subpart OOOOa standards for two years and revisit the entirety of the 2016 standard, but the rule has not been finalized. Rather, in February 2018, the EPA finalized amendments to certain requirements of the 2016 final rule and, in September 2018, the agency proposed additional amendments that included rescission or revision of certain requirements such as fugitive emission monitoring frequency. Furthermore, in 2016, the BLM published a final rule to reduce methane emissions by regulating venting, flaring and leaking from oil and gas operations on public lands. However, in September 2018, the BLM published a final rule that rescinds most of the requirements in the 2016 final rule and codifies the BLM s prior approach to venting and flaring. The rescission of the requirements in the 2016 final rule is being challenged in federal court.

At the state level, some states are considering and other states have issued requirements for the performance of leak detection programs that identify and repair methane leaks at certain oil and gas sources. State rules may be more stringent than federal rules. Compliance with the EPA s 2016 rule and the BLM s 2016 rule, to the extent either are in effect, or with any future federal or state methane regulations could, among other things, require installation of new emission controls on some of the Company s equipment and significantly increase the Company s capital expenditures and operating costs.

Internationally, in late 2015, the U.S. joined other countries in entering into a United Nations sponsored non-binding agreement in Paris, France for nations to limit their GHG emissions through individually determined emission reduction goals every five years beginning in 2020. In August 2017, the U.S. State Department informed the United Nations of the United States intention to withdraw from this Paris agreement, which provides for a four-year exit process beginning when it took effect in November 2016.

The adoption and implementation of any federal or state legislation or regulations or international agreements that require reporting of GHGs or otherwise restrict emissions of GHGs from the Company s equipment and operations could require the Company to incur increased capital and operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements, including the imposition of a carbon tax, any of which could have a material adverse effect on the Company s business, financial condition and results of operations. Moreover, such new legislation or regulatory programs as well as conservation plans and efforts undertaken in response to climate change could also materially and adversely affect demand for the oil, NGLs and gas the Company produces and lower the value of its reserves. Depending on the severity of any such limitations, the effect on the value of the Company s reserves could be material.
Non-governmental activism directed at shifting funding away from companies with energy-related assets could result

in limitations or restrictions on certain sources of funding for the energy sector. In addition, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits brought by public and private entities against oil and gas companies in connection with their GHG emissions.

Should the Company be targeted by any such litigation, it may incur substantial costs, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods, droughts and other extreme climatic events. If any such effects were to occur, they could have a material adverse effect on the Company s exploration and production operations.

Laws and regulations pertaining to protection of threatened and endangered species or to critical habitat, wetlands and natural resources could delay, restrict or prohibit the Company s operations and cause it to incur substantial costs that may have a material adverse effect on the Company s development and production of reserves.

The federal ESA and comparable state laws were established to protect endangered and threatened species. Under the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species habitat. Similar protections are offered to migratory birds under the Federal Migratory Bird Treaty Act. Oil and gas operations in the Company s operating areas may be adversely affected by seasonal or permanent restrictions imposed on drilling activities by the U.S. Fish and Wildlife Services (the FWS) that are designed to protect various wildlife, which may materially restrict the Company s access to federal or private land use. Permanent restrictions imposed to protect endangered and threatened species could prohibit drilling in certain areas, impact suppliers of critical materials or services, or require the implementation of expensive mitigation measures. Additionally, federal statutes, including the CWA, the OPA and CERCLA, as well as comparable state laws, prohibit certain actions that adversely affect critical habitat, wetlands and natural resources. If harm to species or damages to wetlands, habitat or natural resources occur or may occur, government entities or, at times, private parties may act to prevent oil and gas exploration or development activities or seek damages for harm to species, habitat or natural resources resulting from drilling, construction or releases of petroleum hydrocarbons, wastes, hazardous substances or other regulated materials, and, in some cases, may seek criminal penalties.

Moreover, as a result of one or more settlements entered into by the FWS, the agency is required to make determinations on the potential listing of numerous species as endangered or threatened under the ESA. The designation of previously unprotected species as threatened or endangered in areas where the Company conducts operations could cause the Company to incur increased costs arising from species protection measures or could result in delays, restrictions or prohibitions on its development and production activities that could have a material adverse effect on the Company s ability to develop and produce reserves.

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

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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.

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.

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.

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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.

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, 2018.

	2018		2017		2016	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory:						
Oil						
Gas						
Dry						
Development:						
Oil	28	6.1	26	6.3	27	3.6
Gas						
Dry						
Total:						
Oil	28	6.1	26	6.3	27	3.6
Gas						
Dry						
	28	6.1	26	6.3	27	3.6

Oil and Gas Production

As of December 31, 2018, 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	1076	555
Gas Wells	736	519

(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, NGL and natural gas for each of the three years ended December 31, 2018. 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.

	2018	2017	2016
Oil (barrels)	1,187,000	1,004,000	670,000
NGL (barrels)	463,000	305,000	196,000
Gas (Mcf)	3,735,000	3,571,000	3,699,000

The following table sets forth our average sales prices together with our average production costs per unit of production for the three years ended December 31, 2018.

	2018	2017	2016
Average sales price per barrel of oil	$ 60.46	$ 49.85	$ 39.73
Average sales price per barrel of NGL	$ 27.79	$ 23.27	$ 15.60
Average sales price per Mcf of natural gas	$ 2.30	$ 2.73	$ 2.32
Average production costs per net equivalent barrel of oil(1)	$ 13.12	$ 14.30	$ 17.13

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

Average oil, NGL and gas prices received including the impact of derivatives were:

	2018	2017	2016
Average sales price per barrel of oil	$ 57.39	$ 49.70	$ 39.73
Average sales price per barrel of NGL	$ 18.17	$ 23.27	$ 15.60
Average sales price per Mcf of natural gas	$ 3.37	$ 2.73	$ 2.33

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, 2018. 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	169,791	69,736			169,791	69,736
Mineral fee acreage	1,640	117	19,257	417	20,897	534
Total	171,431	69,853	19,257	417	190,688	70,270

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, 2018, is 58 acres for the year ending December 31, 2019, zero in 2020 and zero acres in 2021.

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, 2018. The professional qualifications of the technical persons primarily responsible for overseeing the preparation of the reserve 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 and geologists with between approximately twenty and thirty-five years of industry experience, and between eight and twenty-five 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.

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

	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
As of December 31,	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe)
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
2018	6,404	2,707	21,065	12,622	10	12	124	43	6,414	2,719	21,189	12,665

(a) In computing total reserves on a barrels of oil equivalent (Boe) basis, 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, 2016, we had undeveloped reserves of 1,135 Mboe, attributable to 20 wells that were all put on production in the first quarter of 2017. During 2017, 22 horizontal wells were drilled and completed in West Texas, two in Oklahoma, and one vertical well in the Gulf Coast of Texas. In addition, we had an increase in reserves from overriding royalty interest in nine horizontal wells drilled in Oklahoma by other operators.

At December 31, 2017 our reserve report included 779 MBoe of proved undeveloped reserves attributable to 22 horizontal wells that were all completed in 2018, and therefore, 100% of these reserves were converted to proved developed in the 2018 year-end reserves report.

In 2018, the Company completed and put on production nine horizontal wells in West Texas and five horizontal wells in Oklahoma. The Company also increased reserves through overriding royalty interest in 18 new horizontal wells drilled by other operators, primarily in Oklahoma. An additional eight wells that were drilled and completed in 2018 in our West Texas horizontal development program were designated as Shut-in at year-end, and have been brought on production in February, 2019.

In the first quarter of 2019, in West Texas, we are actively participating in two horizontal wells for 46% interest, as well as participating in a third horizontal well for 5.3% interest. One of each of these three wells will be completed in the Wolfcamp A , Jo Mill and Lower Spraberry. All three wells were designated as probable undeveloped as of December 31, 2018, and, therefore, are not included in the 2018 year-end reserve report. In Oklahoma, we drilled and completed six wells that were designated as Shut-in at year-end, five of which have been put on-line in the first quarter of 2019, and we are participating in a seventh well that is in the process of being drilled or completed. The Company has 10% interest in one of the seven wells and less than one percent interest in the remaining six wells, with an estimated total cost of approximately $1.46 Million net to the Company s interest. 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

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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.

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, 2018, are summarized as follows (in thousands of dollars):

	Proved Developed		Proved Undeveloped		Total			
As of December 31,	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Future Net Revenue	Present Value 10 Of Future Net Revenue	Present Value 10 Of Future Income Taxes	Standardized Measure of Discounted Cash flow
2016	$ 56,467	$ 46,827	$ 18,114	$ 10,403	$ 74,581	$ 57,230	$ 4,993	$ 52,237
2017	$ 160,737	$ 111,614	$ 13,564	$ 6,100	$ 174,301	$ 117,714	$ 10,800	$ 106,914
2018	$ 239,337	$ 161,376	$ 767	$ 525	$ 240,104	$ 161,901	$ 23,992	$ 137,909

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 $3.10 per MMBtu in 2018 as compared to $2.98 per MMBtu in 2017 and $2.49 per MMBtu in 2016. Oil prices, based on the NYMEX first of the month average price, were $65.56 per barrel in 2018 as compared to

$51.34 per barrel in 2017, and $42.75 per barrel in 2016. Since January 1, 2019, 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.

District Information

The following table represents certain reserve and well information as of December 31, 2018

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves as of December 31, 2018 (MBoe)						
Developed	559	814	2,839	8,401	8	12,622
Undeveloped			43			43
Total	559	814	2,882	8,401	8	12,665
Average Daily Production (Boe per day)	244	572	977	4,248	7	6,048
Gross Productive Wells (Working Interest and ORRI Wells)	547	293	580	558	105	2,083
Gross Productive Wells (Working Interest Only)	500	263	430	519	45	1,757
Net Productive Wells (Working Interest Only)	469	164	227	256	4	1,120
Gross Operated Productive Wells	476	211	243	354		1,284
Gross Operated Water Disposal, Injection and Supply wells	1	9	67	7		84

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, 2018, we had interest in 500 wells (469 net), of which 477 wells are operated. There are multiple producing intervals that include the Big Lime, Injun, Blue Monday, Weir, Berea, Gordon and Devonian Shale formations at depths primarily ranging from 1,600 to 5,600 feet. Average net daily production in 2018 was 244 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, 2018, we had 559 MBoe of proved developed reserves (substantially all natural gas) in the Appalachian region, constituting 4% 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, 2019, 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 263 producing wells (164 net) in the Gulf Coast region as of December 31, 2018, of which 220 wells are operated by us. Average daily production in 2018 was 572 Boe. At December 31, 2018, we had 925 MBoe of proved reserves in the Gulf Coast region, which represented 6% of our total proved reserves. We

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maintain an acreage position of over 12,700 gross (5,120 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, 2019, 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.

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, 2018, we had 580 wells (227 net) in the Mid-Continent area, of which 310 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 2018 was 977 Boe. At December 31, 2018, we had 2,882 MBoe of proved reserves in the Mid-Continent area, or 23% of our total proved reserves. We maintain an acreage position of approximately 81,800 gross (10,900 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, 2019, the Mid-Continent region is participating in the drilling and completion of seven wells included as Proved Undeveloped in the 2018 year-end reserve report.

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 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, 2018, we had 519 wells (256 net) in the West Texas area, of which 361 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 2018 was 4,248 Boe. At December 31, 2018, we had 8,401 MBoe of proved reserves in the West Texas area, or 66% of our total proved reserves. We maintain an acreage position of approximately 20,292 gross (12,824 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, Jo Mill, and Wolfcamp intervals. We operate a field service group in this region utilizing nine workover rigs,five hot oiler trucks, one kill truck and one roustabout 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, 2018, the Company was participating in three Probable Undeveloped horizontal drilling locations not included in the 2018 year-end reserve report. All three of these wells have been drilled and are expected to be completed and producing in the second quarter of 2019.

Item 3. LEGAL PROCEEDINGS.

None.

Item 4. MINE SAFETY DISCLOSURES.

Not applicable.

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PART II

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

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

	High	Low
2018		
First Quarter	$ 56.20	$ 47.10
Second Quarter	71.00	52.00
Third Quarter	80.50	68.05
Fourth Quarter	80.40	67.01
2017		
First Quarter	$ 59.00	$ 45.00
Second Quarter	50.05	39.80
Third Quarter	52.00	43.50
Fourth Quarter	55.00	45.50

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

As of March 20, 2019, there were 306 registered holders of the common stock.

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

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Issuer Purchases of Equity Securities

In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012 and June 13, 2018, the Board of Directors of the Company approved an additional 500,000 and 200,000 respectively, shares of the Company s stock to be included in the stock repurchase program. A total of 3,700,000 shares have been authorized, to date, under this program. Through December 31, 2018, a total of 3,506,537 shares have been repurchased under this program for $68,736,426 at an average price of $19.60 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.

2018 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	178	$	55.55	122,736
February	64,841		50.18	57,895
March	2,199		52.50	55,696
April	4,787		54.08	50,909
May	417		69.81	50,492
June	417		69.35	250,075
July	34,522		74.99	215,553
August	93		75.49	215,460
September	111		75.43	215,349
October	10,219		75.08	205,130
November	9,758		76.61	195,372
December	1,909		74.19	193,463
Total / Average	129,451	$	61.46	

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.

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 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, 2018 was $39.1 million, compared to $40.1 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 2019, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2019 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 $100 million. As of March 31, 2019, the Company has $73.5 million in outstanding borrowings and $26.5 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 2019. 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	
	2019	2020	2019	2020
Natural Gas (MMBTU)	749,000	180,000	$ 2.93	$ 2.95
Natural Gas Liquids (barrels)	60,000		$ 21.66	
Oil (barrels)	490,100	225,500	$ 53.35	$ 58.43

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.

We participated in 28 gross (6.1 net) horizontal wells drilled and completed in 2018; 14 of these were producing at year-end while the remaining 14 wells were categorized as shut-in and started producing in the first quarter of 2019. Of the total 28 wells, 15 are in our West Texas horizontal drilling program, while 13 are in our Oklahoma Scoop-Stack horizontal development program. In addition, the Company participated in the drilling of three Probable Undeveloped horizontal wells in Upton County, Texas targeting pay intervals above the Middle Wolfcamp: one in the Wolfcamp A , one in the Jo Mill and one in the Lower Spraberry. These wells are expected to be in production during the second quarter of 2019. These are important tests of the economic viability of the target reservoirs, both for the 1,300 acre block in which they were drilled, in which Prime holds between 5% and 48% working interest, as well as for our nearby 2,600 leasehold acres with the same potential. Our share of the cost of these three wells will be approximately $8.9 million. If favorable results are achieved from these three wells, an additional 21 locations are likely to be drilled in the near future at a gross cost of approximately $182 million with the Company s share being approximately $60 million. In the nearby 2,600 acres, Prime holds between 14% and 56% interest and if favorable results from these three wells occur it is likely to spur the drilling of as many as 96 additional horizontal wells on this acreage over the coming years. The cost of such development would be approximately $748 million with the Company s share being approximately $284 million. The actual number of wells that will be drilled, the cost, and the timing of drilling will vary based upon many factors, including commodity market conditions.

In the first quarter of 2019, the Company was participating with 10 percent interest in the drilling of one well, as well as participating with less than 1 percent in seven other wells, all in Grady County, Oklahoma. We anticipate these wells to be on-line in the second quarter of 2019.

The Exploration, Development and Recent Activities section in Part I above describes in more detail the recent activities of the Company. The focus of our future activity will be on the continued development of our resource s potential in the West Texas horizontal drilling program as well as our Scoop-Stack horizontal drilling program acreage in Oklahoma in order to maximize cash flow and return on investment.

The Company maintains an acreage position of 20,292 gross (12,824 net) acres in the Permian Basin in West Texas, primarily in Reagan, Upton, Martin and Midland counties and we believe this acreage has significant resource potential in as many as 10 reservoirs, including benches of the Spraberry, Jo Mill, and Wolfcamp that support the potential drilling of as many as 250 additional horizontal wells.

In Oklahoma, the Company s horizontal activity is primarily focused in Canadian, Grady, Kingfisher and Garvin counties where we have approximately 2,215 net leasehold acres. We believe this acreage has significant

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additional resource potential that could support the drilling of as many as 161 new horizontal wells based on an estimate of four to ten wells per section, depending on the reservoir target area, with our share of the capital expenditures being approximately $82 million at an average 10% ownership level.

To supplement cash flow and finance our drilling program during 2018, the Company sold or farmed-out leasehold rights through several transactions, receiving gross proceeds of approximately $3.1 million in exchange for leasehold interest in Oklahoma, Kansas, Colorado, Texas and Wyoming. This includes the sale of 1,808 net acres and 20 wells in Garfield County, Oklahoma, and 5,005 net acres along with 54 wells, in Yuma County, Colorado and Cheyenne County, Kansas.

As of March 2019, the Company has $464 thousand outstanding on our equipment financing facilities which are secured by substantially all of our field service equipment. The majority of our capital spending is discretionary, and the ultimate level of expenditures will be dependent on our assessment of the oil and gas business environment, the number and quality of oil and gas prospects available, the market for oilfield services, and oil and gas business opportunities in general.

The Company has in place both a stock repurchase program and a limited partnership interest repurchase program. Spending under these programs in 2018 was $8 million. The Company expects continued spending under these programs in 2019.

Results of Operations:

2018 and 2017 Compared

We reported net income for 2018 of $14.5 million, or $6.95 per share, compared to $42.0 million, or $18.99 per share for 2017. This increase was due to increases in oil, NGL and natural gas production and sales compared to 2017 offset by reduced gains related to the sale of acreage. The significant components of net income are discussed below.

Oil, NGL and gas sales increased $26.3 million, or 39.4% to $93.2 million for the year ended December 31, 2018 from $66.9 million for the year ended December 31, 2017. Crude oil, NGL 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 $10.61 per barrel, or 21.3% on crude oil, decreased an average of $1.18 per barrel, or 8.3% on NGL and decreased $0.43 per Mcf, or 15.7% on natural gas during 2018 as compared to 2017.

Our crude oil production increased by 183,000 barrels, or 18.2% from 1,004,000 barrels for the year ended December 31, 2017 to 1,187,000 barrels for the year ended December 31, 2018. Our NGL production increased by 158,000 or 51.8% from 305,000 barrels for the year ended December 31, 2017 to 463,000 barrels for the year ended December 31, 2018. Our natural gas production increased by 164 MMcf, or 4.6% from 3,571 MMcf for the year ended December 31, 2017 to 3,735 MMcf for the year ended December 31, 2018. The increase in crude oil, NGL and natural gas production volumes are a result our continued drilling success in the West Texas and Oklahoma regions as we place new wells into production offset by the natural decline of existing properties.

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The following table summarizes the primary components of production volumes and average sales prices realized for the years ended December 31, 2018 and 2017 (excluding realized gains and losses from derivatives).

	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017	Increase / (Decrease)	Increase / (Decrease)
Barrels of Oil Produced	1,187,000	1,004,000	183,000	18.2%
Average Price Received	$ 60.46	$ 49.85	$ 10.61	21.3%
Oil Revenue (In 000 s)	$ 71,766	$ 50,041	$ 21,725	43.4%
Mcf of Gas Sold	3,735,000	3,571,000	164,000	4.6%
Average Price Received	$ 2.30	$ 2.73	$ (0.43)	(15.7)%
Gas Revenue (In 000 s)	$ 12,859	$ 9,745	$ 3,114	32.0%
Barrels of Natural Gas Liquids Sold	463,000	305,000	158,000	51.8%
Average Price Received	$ 13.12	$ 14.30	$ (1.18)	(8.3)%
Natural Gas Liquids Revenue (In 000 s)	$ 8,590	$ 7,097	$ 1,493	21.0%
Total Oil & Gas Revenue (In 000 s)	$ 93,215	$ 66,883	$ 26,332	39.4%

Oil, Natural Gas and NGL Derivatives 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 condensed consolidated statements of operations. As oil and natural gas prices remain volatile, mark-to-market accounting treatment creates volatility in our revenues.

The following table summarizes the results of our derivative instruments for the twelve months ended December 2018 and 2017:

	Twelve months ended December 31, 2018	Twelve months ended December 31, 2017
Oil derivatives realized gains (losses)	$ (3,642)	$ (146)
Oil derivatives unrealized gains (losses)	5,600	(1,720)
Total gains (losses) on oil derivatives	$ 1,958	$ (1,866)
Natural gas derivatives realized gains (losses)	$ (278)	$ (9)
Natural gas derivatives unrealized gains (losses)	(394)	2,267
Total gains (losses) on natural gas derivatives	$ (672)	$ 2,258
NGL derivatives realized (losses)	$ (175)	$

NGL derivatives unrealized gains (losses)	124	
Total gains (losses) on NGL derivatives	(51)	
Total gains (losses) on oil, natural gas and NGL derivatives	$ 1235	$ 392

Prices received for the twelve months ended December 31 2018 and 2017, respectively, including the impact of derivatives were:

	2018	2017	Increase / (Decrease)	Increase / (Decrease)
Oil Price	$ 57.39	$ 49.70	$ 7.70	15.5%
Gas Price	$ 3.37	$ 2.73	$ 0.64	23.5%
NGLS Price	$ 18.17	$ 23.27	$ (5.09)	(21.9)%

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Field service income increased $2 million, or 12.7% from $15.7 million for the year ended December 31, 2017 to $17.7 million for the year ended December 31, 2018. Rates on our workover rigs and hot oiler services improved during 2018 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 $4.1 million, or 13.3% to $35.0 million for the year ended December 31, 2018 from $30.9 million for the year ended December 31, 2017. 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 increased $2.5 million, or 20.8% from $12.0 million for the year ended December 31, 2017 to $14.5 million for the year ended December 31, 2018. Field service expenses primarily consist of salaries and vehicle operating expenses which have increased during 2018 related to increased utilization of our equipment services.

Depreciation, depletion, amortization and accretion on discounted liabilities increased $1.6 million, or 4.4% from $36.1 million for the year ended December 31, 2017 to $37.7 million for the year ended December 31, 2018. 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 $4.0 million, or 41.7% to $13.6 million for the year ended December 31, 2018 from $9.6 million for the year ended December 31, 2017. This increase in 2018 reflects the combination of a reduction in reimbursements related to the decrease in gains on sales of properties from 2017 to 2018 and increases in personnel costs.

Gain on sale and exchange of assets of $3.7 million for the year ended December 31, 2017 and $41.3 million for the year ended December 31, 2017 consists of sales of non-producing acreage and oil and gas interests and non-essential field service equipment.

Interest expense increased $1.1 million, or 47.8% from $2.3 million for the year ended December 31, 2017 to $3.4 million for the year ended December 31, 2018. This increase relates to an increase in average debt outstanding during 2018 as compared to 2017 combined with an increase in weighted average interest rates during the 2018 periods. The average interest rate paid on outstanding bank borrowings under its revolving credit facility during 2018 and 2017 were 5.33% and 4.97%, respectively. As of December 31, 2018 and 2017, the total outstanding borrowings under its revolving credit facility were $65.5 million and $47.7 million, respectively.

Tax expense of $3.0 million was recorded for the year ended December 31, 2018, versus a tax benefit of $7.8 million for the year ended December 31, 2017. The 2017 tax benefit was directly related to the effect of the Tax Cuts and Jobs Act passed in 2017, based on the re-measurement of deferred tax assets and liabilities at the lower corporate tax rate contained in the bill.

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.

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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, 2018, 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, 2018.

Management s Report on Internal Control Over Financial Reporting

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

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2018. 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, 2018.

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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, 2018 that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

Item 9B. OTHER INFORMATION.

None.

PART III

Item 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

Information relating to the Company s Directors, nominees for Directors and executive officers will be included in the Company s definitive proxy statement relating the Company s Annual Meeting of Stockholders to be held in June, 2019 which will be filed with the U.S. Securities and Exchange Commission within 120 days of December 31, 2018, 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, 2019, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2018, 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, 2019, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2018, 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, 2019 which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2018, 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, 2019, which will be filed with the U. S. Securities and Exchange Commission within 120 days of December 31, 2018, 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	Certificate of Incorporation of PrimeEnergy Resources Corporation, as amended and restated of December 21, 2018, (filed as Exhibit 3.1 of PrimeEnergy Resources Corporation Form 8-K on December 27, 2018, and incorporated herein by reference).
3.2	Bylaws of PrimeEnergy Resources Corporation as amended and restated as of May 20, 2015 (filed as Exhibit 3.2 of PrimeEnergy Resources Corporation Form 8-K on May 21, 2015 and incorporated herein by reference).
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2004).
10.22.5.10	Third Amended and Restated Credit Agreement dated as of February 15, 2017 among PrimeEnergy Resources 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 Resources Corporation Form 10-K for the year ended December 31, 2016).
10.22.5.10.1	FIRST AMENDMENT TO THIRD AMENDED AND RESTATED CREDIT AGREEMENT dated as of December 22, 2017 among PRIMEENERGY RESOURCES 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, (Incorporated by reference to Exhibit 10.22.5.10.1 to PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2017).
10.22.5.10.2	SECOND AMENDMENT TO THIRD AMENDED AND RESTATED CREDIT AGREEMENT dated as of July 17, 2018 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, (Incorporated by reference to Exhibit 10.22.5.10.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2018).
10.22.5.10.3	THIRD AMENDMENT TO THIRD AMENDED AND RESTATED CREDIT AGREEMENT dated as of January 8, 2019, among PRIMEENERGY RESOURCES 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).
10.22.5.11	Amended, Restated and Consolidated Guaranty dated as of February 15, 2017, among PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Prime Offshore L.L.C. in favor of Compass Bank, as Administrative Agent for the Lenders (Incorporated by reference to Exhibit 10.22.5.11 to PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2016).

Exhibit No.	
10.22.5.12	Amended, Restated and Consolidated Pledge and Security Agreement dated as of February 15, 2017, among PrimeEnergy Resources 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 Resources 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 Resources Corporation Form 10-Q for the quarter ended March 31, 2017).
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 Resources 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 Resources 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 Resources 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 Resources Corporation Form 10-Q for the quarter ended September 30, 2013).
10.23.3	Guaranty dated July 31, 2013, made by PrimeEnergy Resources Corporation in favor of JP Morgan Chase Bank, N.A. (Incorporated by reference to Exhibit 10.23.3 to PrimeEnergy Resources 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 Resources 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 Resources 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 Resources Corporation Form 10-Q for the quarter ended September 30, 2014).
10.24.3	Guaranty dated July 29, 2014, made by PrimeEnergy Resources Corporation in favor of JP Morgan Chase Bank, N.A. (Incorporated by reference to Exhibit 10.24.3 to PrimeEnergy Resources

Corporation Form 10-Q for the quarter ended September 30, 2014).

Exhibit No.	
10.25	Purchase and Sale Agreement dated as of January 25, 2017, among PrimeEnergy Resources 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 Resources Corporation Form 10-K for the year ended December 31, 2016).
14	PrimeEnergy Resources Corporation Code of Business Conduct and Ethics, as amended December 16, 2011 (Incorporated by reference to Exhibit 14 of PrimeEnergy Resources Corporation Form 10-K for the year ended December 31, 2011).
21	Subsidiaries (filed herewith).
23	Consent of Ryder Scott Company, L.P. (filed herewith).
31.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
31.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(a)/15d-14(a) of the Securities Exchange Act of 1934, as amended (filed herewith).
32.1	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
32.2	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (filed herewith).
99.1	Summary Reserve Report dated January 28, 2019, of Ryder Scott Company, L.P. (filed herewith).
101.INS	XBRL (eXtensible Business Reporting Language) Instance Document (filed herewith)
101.SCH	XBRL Taxonomy Extension Schema Document (filed herewith)
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document (filed herewith)
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document (filed herewith)
101.LAB	XBRL Taxonomy Extension Label Linkbase Document (filed herewith)
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document (filed herewith)

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, on the 15th day of April, 2019.

PrimeEnergy Resources 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 15th day of April, 2019.

/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/ THOMAS S.T. GIMBEL	Director	/s/ JAN K. SMEETS	Director
Thomas S.T. Gimbel		Jan K. Smeets	

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To The Board of Directors and Stockholders of

PrimeEnergy Resources Corporation and Subsidiaries:

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PrimeEnergy Resources Corporation and Subsidiaries (the Company) as of December 31, 2018 and 2017, the related consolidated statements of operations, 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, 2018 and 2017, and the results of its operations and its cash flows for each of the years then ended, 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 15, 2019

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEET

(Thousands of dollars)

	As of December 31, 2018	2017
ASSETS		
Current Assets		
Cash and cash equivalents	$ 6,315	$ 8,438
Accounts receivable, net	14,961	16,961
Prepaid obligations	640	756
Derivative asset short-term	1,674	344
Other current assets	144	132
Total Current Assets	23,734	26,631
Property and Equipment		
Oil and gas properties at cost	514,821	476,570
Less: Accumulated depletion and depreciation	(291,152)	(263,569)
	223,669	213,001
Field and office equipment at cost	27,252	26,241
Less: Accumulated depreciation	(20,496)	(19,267)
	6,756	6,974
Total Property and Equipment, Net	230,425	219,975
Derivative asset long-term and other assets	893	159
Total Assets	$ 255,052	$ 246,765
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 9,553	$ 24,615
Accrued liabilities	18,431	16,294
Current portion of long-term debt	698	2,378
Current portion of asset retirement and other long-term obligations	1,687	2,309
Derivative liability short-term	88	1,509
Due to Related Parties	5	65
Total Current Liabilities	30,462	47,170
Long-Term Bank Debt	65,547	48,459
Asset Retirement Obligations	19,647	21,269
Derivative Liability Long-Term	10	1,913

Deferred Income Taxes	32,828	24,962
Other Long-Term Obligations	555	553
Total Liabilities	149,049	144,326
Commitments and Contingencies		
Equity		
Common stock, $.10 par value; 2018: Authorized: 2,810,000 shares, outstanding: 2,039,919 shares; 2017: Authorized: 4,000,000 shares, outstanding: 2,169,370 shares	281	383
Paid-in capital	7,388	8,729
Retained earnings	125,644	138,320
Treasury stock, at cost; 2018: 770,081 shares; 2017: 1,667,027 shares	(31,304)	(52,123)
Total Stockholders Equity PrimeEnergy	102,009	95,309
Non-controlling interest	3,994	7,130
Total Equity	106,003	102,439
Total Liabilities and Equity	$ 255,052	$ 246,765

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

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF OPERATIONS

(Thousands of dollars, except per share amounts)

	For the Year Ended December 31, 2018	For the Year Ended December 31, 2017
Revenues		
Oil and gas sales	$ 71,766	$ 50,041
Natural gas sales	12,859	9,745
Natural gas liquids sales	8,590	7,097
Realized loss on derivative instruments, net	(4,095)	(155)
Field service income	17,732	15,704
Administrative overhead fees	5,720	6,158
Unrealized gain on derivative instruments	5,330	547
Other income	198	173
Total Revenues	118,100	89,310
Costs and Expenses		
Lease operating expense	34,996	30,880
Field service expense	14,475	11,990
Depreciation, depletion, amortization and accretion on discounted liabilities	37,729	36,068
General and administrative expense	13,550	9,646
Total Costs and Expenses	100,750	88,584
Gain on Sale and Exchange of Assets	3,662	41,258
Income from Operations	21,012	41,984
Other Income and Expenses		
Less: Interest expense	3,413	2,310
Add: Interest income	44	7
Income Before Provision (Benefit) for Income Taxes	17,643	39,681
Provision (Benefit) for Income Taxes	2,978	(7,753)
Net Income	14,665	47,434
Less: Net Income Attributable to Non-Controlling Interest	136	5,436
Net Income Attributable to PrimeEnergy	$ 14,529	$ 41,998
Basic Income Per Common Share	$ 6.96	$ 18.99
Diluted Income Per Common Share	$ 5.11	$ 14.18

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

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF EQUITY

(Thousands of dollars)

	Common Stock					Total		
			Additional			Stockholders	Non-	
			Paid-In	Retained	Treasury	Equity	Controlling	Total
	Shares	Amount	Capital	Earnings	Stock	PrimeEnergy	Interest	Equity
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
Purchase 129,451 shares of common stock					(7,956)	(7,956)		(7,956)
Retirement of 1,026,397 shares of common stock	(1,026,397)	(102)	(1,468)	(27,205)	28,775			
Net income				14,529		14,529	136	14,665
Purchase of non-controlling interest			127			127	(192)	(65)
Distributions to non-controlling interest							(3,080)	(3,080)
Balance at December 31, 2018	2,810,000	$ 281	$ 7,388	$ 125,644	$ (31,304)	$ 102,009	$ 3,994	$ 106,003

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

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENT OF CASH FLOWS

(Thousands of dollars)

	For the Year Ended December 31,	
	2018	2017
Cash Flows from Operating Activities:		
Net Income	$ 14,665	$ 47,434
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	37,729	36,068
Gain on sale of properties	(3,662)	(41,258)
Unrealized (gain) on derivative instruments	(5,330)	(547)
Provision (Benefit) for deferred income taxes	7,866	(12,538)
Changes in assets and liabilities:		
Accounts receivable	2,000	(9,561)
Due to related parties	(60)	101
Inventories	11	(9)
Prepaid expenses and other assets	(1,226)	(344)
Accounts payable	(15,063)	12,650
Accrued liabilities	2,136	8,111
Net Cash Provided by Operating Activities	39,066	40,107
Cash Flows from Investing Activities:		
Capital expenditures, including exploration expense	(47,073)	(59,361)
Proceeds from sale of properties and equipment	3,233	46,231
Net Cash Used in by Investing Activities	(43,840)	(13,130)
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(7,956)	(5,650)
Purchase of non-controlling interests	(65)	(308)
Increase in long-term bank debt and other long-term obligations	55,800	64,853
Repayment of long-term bank debt and other long-term obligations	(42,048)	(82,628)
Distribution to non-controlling interest	(3,080)	(4,917)
Net Cash Provided by (used in) provided by Financing Activities	2,651	(28,650)
Net Decrease in Cash and Cash Equivalents	(2,123)	(1,673)
Cash and Cash Equivalents at the Beginning of the Year	8,438	10,111
Cash and Cash Equivalents at the End of the Year	$ 6,315	$ 8,438

Supplemental Disclosures:		
Income taxes paid during the year	$ 2,130	$ 414
Interest paid during the year	$ 3,535	$ 2,339

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

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Description of Operations and Significant Accounting Policies

Nature of Operations:

PrimeEnergy Resources Corporation (PERC), a Delaware corporation, was organized in March 1973 and is engaged in the development, acquisition and production of oil and natural gas properties. PrimeEnergy Resources 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 approximately 1,400 active wells and owns non-operating interests and royalties in approximately 800 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. PERC owns Eastern Oil Well Service Company (EOWSC) and EOWS Midland Company (EMID) which perform oil and gas field servicing. PERC 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 3 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 Resources 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 footnotes 2 and 4 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, 2018, and 2017, we had no valuation allowance.

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

General and Administrative Expenses:

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

Earnings Per Common Share:

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

Statements of Cash Flows:

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

Concentration of Credit Risk:

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

Hedging:

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

The financial instruments are accounted for in accordance with applicable accounting standards for derivative instruments and hedging activities. Such standards require that applicable derivative instruments be measured at fair market value and recognized as assets or liabilities in the balance sheet. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and the resulting designation is generally established at the inception of a derivative. For derivatives designated as cash flow hedges and meeting applicable effectiveness guidelines, changes in fair value, to the extent effective, are recognized in other comprehensive income until the hedged item is recognized in earnings. 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:

On January 1, 2018, PrimeEnergy adopted ASU 2014-09, Revenue from Contracts with Customers (ASC 606), using the modified retrospective method. The Company elected to evaluate all contracts at the date of initial application. While there was no impact to the opening balance of retained earnings as a result of the adoption, certain items previously netted in revenue are now recognized as lease operating expense in the Company s statement of consolidated operations. The amounts are immaterial to the financial statements, and prior comparative periods have not been restated and continue to be reported under the accounting standards in effect for those periods. Adoption of the new standard is not anticipated to have a material impact on the Company s net earnings on an ongoing basis.

The Company applies the provisions of ASC 606 for revenue recognition to contracts with customers. Sales of crude oil, natural gas, and natural gas liquids (NGLs) are included in revenue when production is sold to a customer in fulfillment of performance obligations under the terms of agreed contracts. Performance obligations primarily comprise delivery of oil, gas, or NGLs at a delivery point, as negotiated within each contract. Each barrel of oil, million Btu (MMBtu) of natural gas, or other unit of measure is separately identifiable and represents a distinct performance obligation to which the transaction price is allocated. Performance obligations are satisfied at a point in time once control of the product has been transferred to the customer. The Company considers a variety of facts and circumstances in assessing the point of control transfer, including but not limited to: whether the purchaser can direct the use of the hydrocarbons, the transfer of significant risks and rewards, the Company s right to payment, and transfer of legal title. In each case, the term between delivery and when payments are due is not significant.

PrimeEnergy records trade accounts receivable for its unconditional rights to consideration arising under sales contracts with customers. The carrying value of such receivables, net of the allowance for doubtful accounts, represents estimated net realizable value. The Company routinely assesses the collectability of all material trade and other receivables. The Company accrues a reserve on a receivable when, based on the judgment of management, it is probable that a receivable will not be collected and the amount of any reserve may be reasonably estimated. PrimeEnergy has concluded that the disaggregation of revenue by product appropriately depicts how the nature, amount, timing, and uncertainty of revenue and cash flows are affected by economic factors.

Practical Expedients and Exemptions

PrimeEnergy does not disclose the value of unsatisfied performance obligations for contracts with an original expected length of one year or less or contracts for which variable consideration is allocated entirely to a wholly unsatisfied performance obligation.

PrimeEnergy will utilize the practical expedient to expense incremental costs of obtaining a contract if the expected amortization period is one year or less. Costs to obtain a contract with expected amortization periods of greater than one year will be recorded as an asset and will be recognized in accordance with ASC 340, Other Assets and Deferred Costs. Currently, the Company does not have contract assets related to incremental costs to obtain a contract.

New Pronouncements Issued But Not Yet Adopted

In February 2016, the Financial Accounting Standards Board (FASB) issued ASU 2016-02, Leases (Topic 842), requiring lessees to recognize lease assets and lease liabilities for most leases classified as operating leases under previous GAAP. The guidance is effective for fiscal years beginning after December 15, 2018. In January 2018, the FASB issued ASU 2018-01, which permits an entity an optional election to not evaluate under ASU 2016-02 those existing or expired land easements that were not previously accounted for as leases prior to the adoption of ASU 2016-02. In July 2018, the FASB issued ASU 2018-11, which adds a transition option permitting entities to apply the provisions of the new standard at its adoption date instead of the earliest comparative period presented in the consolidated financial statements. Under this transition option, comparative reporting would not be required, and the provisions of the standard would be applied prospectively to leases in effect at the date of adoption. The Company intends to elect both transitional practical expedients. As allowed under the standard, the Company also applied practical expedients to carry forward its historical assessments of whether existing agreements contain a lease, classification of existing lease agreements, and treatment of initial direct lease costs. The Company also elected to exclude short-term leases (those with terms of 12 months or less) from the balance sheet presentation and will account for non-lease and lease components as a single lease component for all asset classes.

The Company has adopted this guidance as of January 1, 2019. In the normal course of business, the Company enters into various lease agreements for office space and equipment related to its exploration and development activities that are currently accounted for as operating leases. The Company s adoption and implementation of this ASU did not significantly impact its balance sheet. The impact to the Company s consolidated statement of operations and consolidated statement of cash flows is not expected to be material.

In June 2018, the FASB issued ASU 2018-07, Improvements to Nonemployee Share-Based Payment Accounting, to simplify the accounting for share-based transactions by expanding the scope of Topic 718 from only being applicable to share-based payments to employees to also include share-based payment transactions for acquiring goods and services from nonemployees. As a result, the same guidance that provides for employee share-based payments, including most of the requirements related to classification and measurement, applies to nonemployee share-based payment arrangements. ASU 2018-07 is effective for financial statements issued for annual periods beginning after December 15, 2018 and interim periods within those annual periods. Early adoption is permitted. The Company anticipates adopting this guidance for the first quarter of 2019 and does not expect it to have a material impact on its consolidated financial statements.

In August 2018, the FASB issued ASU 2018-13, Disclosure Framework: Changes to the Disclosure Requirements for Fair Value Measurement, which changes the disclosure requirements for fair value measurements by removing, adding, and modifying certain disclosures. ASU 2018-13 is effective for financial statements issued for annual periods beginning after December 15, 2019, and interim periods within those annual periods. Early adoption is permitted. The company is currently evaluating the impact of adoption of this ASU on its related disclosures and does not expect it to have a material impact on its financial statements.

In August 2018, the FASB issued ASU 2018-15, Customer s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That is a Service Contract. This pronouncement clarifies the requirements for capitalizing implementation costs in cloud computing arrangements and aligns them with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. This pronouncement is effective for fiscal years, and for interim periods within those fiscal years, beginning after December 15, 2019. Early adoption is permitted, including adoption in any interim period for which financial statements have not been issued. The Company is currently evaluating the impact of adoption of this ASU on its consolidated financial statements and does not expect it to have a material impact.

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 $65,000 in 2018 and $308,000 in 2017.

During 2018 the Company acquired 1,640 gross (464 net) acres, along with 16.6% to 33.4% working interest ownership in 51 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 2018 the Company sold or farmed out interests in certain non-core undeveloped and developed oil and natural gas properties through a number of individually negotiated transactions in exchange for cash and a royalty or working interest in Oklahoma, Kansas, Colorado, Texas and Wyoming. Proceeds under these agreements were approximately $3.1 million.

During 2017 the Company acquired 118 net 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 2017 the Company 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 acres for $37.4 million, primarily located in Martin County, and in Oklahoma we farmed-out approximately 1,554 net acres primarily in Canadian County for $8.6 million and retained an over-riding royalty interest and potential reversionary interests. These sales were of non-cash flowing mineral interests.

3. Additional Balance Sheet Information

Accounts receivable at December 31, 2018 and 2017 consisted of the following:

	December 31,	
(Thousands of dollars)	**2018**	**2017**
Joint interest billings	$ 1,976	$ 3,173

Trade receivables	1,979	941
Oil and gas sales	6,112	12,941
Tax refund receivable	4,760	
Other	358	4
	15,185	17,059
Less: Allowance for doubtful accounts	(224)	(98)
Total	$ 14,961	$ 16,961

Accounts payable at December 31, 2018 and 2017 consisted of the following:

	December 31,	
(Thousands of dollars)	**2018**	**2017**
Trade	$ 1,174	$ 14,317
Royalty and other owners	6,197	7,073
Partner advances	1,143	1,268
Prepaid drilling deposits	214	67
Other	825	1,890
Total	$ 9,553	$ 24,615

Accrued liabilities at December 31, 2018 and 2017 consisted of the following:

	December 31,	
(Thousands of dollars)	**2018**	**2017**
Compensation and related expenses	$ 2,907	$ 2,449
Property costs	14,993	9,141
Income tax		4,180
Other	531	524
Total	$ 18,431	$ 16,294

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 PERC 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.

On July 17, 2018, the Company and its lenders entered into a Second Amendment to the Third Amended and Restated Credit Agreement. The credit agreement includes modifications for the borrowing base utilization margins and rates by type of borrowing, revises minimum quantifications for individual borrowings, reduces the overall percentage required for commodity hedge agreements, modifies the requirements placed on the companies ability to purchase equity interests 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 $90 million.

At December 31, 2018, the Company had a total of $65.5 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 5.54 % and $24.5 million available for future borrowings. The combined weighted average interest rate paid on outstanding bank borrowings subject to base rate and LIBO interest was 5.33% for the twelve months ended December 31, 2018 as compared to 4.97% for twelve months ended December 31 2017. The Company s borrowings under this credit facility approximates fair value because the interest rates are variable and reflective of market rates.

On January 8, 2019, the Company and its lenders entered into a Third Amendment to the Third Amended and Restated Credit Agreement. The credit agreement includes additions for a Beneficial Ownership Certification on the effective date of the amendment. The agreement includes further clarifications for potential Libor loan market rate issues, swap agreement modifications 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 $100 million.

Equipment Loans:

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, 2018, the Company had a total of $746 thousand 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 $662 thousand and $3.11 million at December 31, 2018 and 2017, respectively, using a discounted cash flow model.

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5. Commitments

Operating Leases:

In February 2019 the Company amended certain lease for office space in Houston providing for payments of $344 thousand and $86 thousand in 2019 and 2020, respectively.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, 2018 are as follows.

(Thousands of dollars)	**Operating Leases**
2019	$ 222
2020	69
2021	17
Total minimum payments	$ 308

In February 2019 the Company amended certain leases for office space in Houston providing for payments of $344 thousand and $86 thousand in 2019 and 2020, respectively.

Rent expense for office space for the years ended December 31, 2018 and 2017 was $659,000 and $659,000, respectively.

Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the years ended December 31, 2018 and 2017 is as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2018**	**2017**
Asset retirement obligation at beginning of period	$ 23,578	$ 17,505
Liabilities incurred	49	45
Liabilities settled	(2,656)	(676)
Accretion expense	1,120	768
Revisions in estimated liabilities	(757)	5,936
Asset retirement obligation at end of period	$ 21,334	$ 23,578

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,

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and is liable for all debts and liabilities of the affiliated Partnerships, to the extent that the assets of a given limited Partnership are not sufficient to satisfy its obligations.

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

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

7. Stock Options and Other Compensation

In May 1989, non-statutory stock options were granted by the Company to four key executive officers for the purchase of shares of common stock. At December 31, 2018 and 2017, 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, 2018 and 2017 are as follows:

	Year Ended December 31,	
(Thousands of dollars)	**2018**	**2017**
Current:		
Federal	$ (4,742)	$ 4,522
State	(146)	262
Total current	(4,888)	4,784
Deferred:		
Federal	7,620	(13,226)
State	246	689
Total deferred	7,866	(12,537)
Total income tax provision (benefit)	$ 2,978	$ (7,753)

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	At December 31,	
(Thousands of dollars)	**2018**	**2017**
Deferred Tax Assets:		
Accrued liabilities	$ 519	$ 349
Allowance for doubtful accounts	51	22
Derivative Contracts	0	684
Disallowed Interest Carryforwards	769	0
Alternative minimum tax credits	4,760	9,919
State Net operating loss carry-forwards	469	528
Percentage depletion carry-forwards		727
General Business Credits	137	
Total deferred tax assets	6,705	12,229
Deferred Tax Liabilities:		
Basis differences relating to managed partnerships	2,296	3,193
Depletion and depreciation	36,711	33,998
Derivative Contracts	526	
Total deferred tax liabilities	39,533	37,191
Net deferred tax liabilities	$ 32,828	$ 24,962

The total provision for income taxes for the years ended December 31, 2018 and 2017 varies from the federal statutory tax rate as a result of the following:

	Year Ended December 31,	
(Thousands of dollars)	**2018**	**2017**
Expected tax expense	$ 3,676	$ 11,643
Revaluation of deferred tax attributes	0	(20,204)
Executive Compensation	553	0
State income tax, net of federal benefit	79	717
Percentage depletion	(140)	(89)
Marginal Well Production Credits	(1,186)	0
Other, net	(4)	180
Total income tax provision (benefit)	$ 2,978	$ (7,753)

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 legislation 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 new lower corporate tax rate. Under the 2017 Tax Act, the company may use alternative minimum tax (AMT) credits to fully offset any regular tax liability. 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 expects to receive a refund of $4.760 million in 2019 based on refundable credits claimed on the 2018 return, and additional $4.760 million in credits against regular tax and refunds of previously paid taxes on its tax returns for the years 2019 through 2021.

The Company is entitled to marginal well production credits under Internal Revenue Code section 45I. In the fourth quarter of 2018, the Company filed amended returns claiming $1.186 million in credits relating to

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2016 and 2017 gas production. The credits cannot be used to offset alternative minimum tax liability, so no refunds were received for those years, but rather the full amount of the credits was carried forward as a General Business Credit.

The Marginal Well Credit is phased out when oil and gas prices exceed certain levels. Although the Internal Revenue Service (IRS) has not yet published anything regarding the availability of the credit in 2018, based on the Company s own calculations, and informal discussions with the IRS, it appears that no credit will be available.

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 availability of the percentage depletion deduction is phased out as an entity s production exceeds certain levels, and based on the Company s increasing production the percentage depletion deduction is becoming less significant.

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 2019 through 2026. Any credits not utilized in a given year due to the allowable credit exceeding the tax liability may be carried forward. No credit may be carried forward past 2026. The value of the credit is calculated net of the federal income tax effect.

The Company 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 2017 return has been selected 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 2016 through 2018 remain open for examination by the relevant taxing authorities.

9. Segment Information and Major Customers

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

The Company sells its oil and natural gas and liquids production to a number of direct purchasers under direct contracts or through other operators under joint operating agreements. Listed below are the purchasers of the Company s production which represented more than 10% of the Company s sales in the year 2018.

Oil:	
Apache Corporation	50.9%
Plains All American Inc.	17.8%
Natural gas and liquids:	
Apache Corporation	35.6%
Targa Pipeline Mid-Continent West Tex, LLC	21.4%

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, 2018 and December 31, 2017:

December 31, 2018	**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, 2018**
(Thousands of dollars)				
Assets				
Commodity derivative contracts	$	$	$ 2,394	$ 2,394
Total assets	$	$	$ 2,394	$ 2,394
Liabilities				
Commodity derivative contracts	$	$	$ (98)	$ (98)
Total liabilities	$	$	$ (98)	$ (98)

December 31, 2017	**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**
(Thousands of dollars)				
Assets				
Commodity derivative contracts	$	$	$ 388	$ 388
Total assets	$	$	$ 388	$ 388
Liabilities				
Commodity derivative contract	$	$	$ (3,422)	$ (3,422)
Total liabilities	$	$	$ (3,422)	$ (3,422)

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

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

The following table sets forth a reconciliation of changes in the fair value of financial assets and liabilities classified as Level 3 in the fair value hierarchy for the year ended December 2018.

(Thousands of dollars)	
Net Liabilities December 31, 2017	$ (3,034)
Total realized and unrealized (gains) losses:	
Included in earnings (a)	1,235
Purchases, sales, issuances and settlements	4,095
Net Assets December 31, 2018	$ 2,296

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(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.

The following table sets forth the effect of derivative instruments on the consolidated balance sheets at December 31, 2018 and 2017:

		Fair Value	
(Thousands of dollars)	**Balance Sheet Location**	**December 31, 2018**	**December 31, 2017**
Asset Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Natural gas commodity contracts	Derivative asset short-term	$ 63	$
Natural gas liquid contracts	Derivative asset short-term	$ 138	$
Crude oil commodity contracts	Derivative asset short-term	$ 1,473	$ 344
Natural gas commodity contracts	Derivative asset long-term and other assets	$ 7	$ 44
Crude oil commodity contracts	Derivative asset short-term and other assets	713	
Total		$ 2,394	$ 388
Liability Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term		(1,504)
Natural gas commodity contracts	Derivative liability short-term	(75)	(5)
Natural gas liquid contracts	Derivative liability short-term	(13)	
Crude oil commodity contracts	Derivative liability long-term		(1,910)
Natural gas commodity contracts	Derivative liability long-term	(10)	(3)
Total		$ (98)	$ (3,422)
Total derivative instruments		$ 2,296	$ (3,034)

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The following table sets forth the effect of derivative instruments on the consolidated statements of operations for the years ended December 31, 2018 and 2017:

(Thousands of dollars)	**Location of gain/loss recognized in income**	**Amount of gain/loss recognized in income 2018**	**2017**
Derivatives not designated as cash-flow hedge instruments:			
Natural gas commodity contracts	Unrealized (loss) gain on derivative instruments, net	(394)	2,267
Crude oil commodity contracts	Unrealized gain (loss) on derivative instruments, net	5,600	(1,720)
Natural gas liquids contracts	Unrealized gain on derivative instruments, net	124	
Natural gas commodity contracts	Realized (loss) on derivative instruments, net	(278)	(9)
Crude oil commodity contracts	Realized (loss) on derivative instruments, net	(3,642)	(146)
Natural gas liquids contracts	Realized (loss) on derivative instruments, net	(175)	
		$ 1,235	$ 392

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 $65,000 during 2018 and $308,000 during 2016.

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 2018 and 2017, the Company purchased 10,000 shares each year from a related party.

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 $338,000 and $374,000 were made in 2018 and 2017, respectively.

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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, 2018			2017		
	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount	Net Income (In 000 s)	Weighted Average Number of Shares Outstanding	Per Share Amount
Basic	$ 14,529	2,089,055	$ 6.96	$ 41,998	2,211,985	$ 18.99
Effect of dilutive securities:						
Options		755,141			750,803	
Diluted	$ 14,529	2,844,196	$ 5.11	$ 41,998	2,962,788	$ 14.18

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. Effective December 21, 2018, pursuant to a vote of the shareholders amending the Articles of Incorporation, the authorized shares of common stock were reduced from 4,000,000 to 2,810,000 shares. The amendment was filed with the Secretary of State in Delaware. The cost of the cancelled shares was determined by use of the first-in, first out valuation method. The cost of reacquired shares was $28,775,000. The cost was allocated between the par value ($0.10) of the shares cancelled; the excess of cost over the par value to paid in capital based upon the average per share amount of paid in capital ($1.43) for all shares from the original issuance; and the excess was charged to retained earnings.

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

CAPITALIZED COSTS RELATING TO

OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2018 and 2017

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2018**	**2017**
Proved Developed oil and gas properties	$ 514,821	$ 476,570
Proved Undeveloped oil and gas properties		
Total Capitalized Costs	514,821	476,570
Accumulated depreciation, depletion and valuation allowance	291,152	263,569
Net Capitalized Costs	$ 223,669	$ 213,001

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION,

EXPLORATION AND DEVELOPMENT ACTIVITIES

Years Ended December 31, 2018 and 2017

(Unaudited)

	Year Ended December 31,	
(Thousands of dollars)	**2018**	**2017**
Development Costs	$ 42,079	$ 59,361

STANDARDIZED MEASURE OF DISCOUNTED FUTURE

NET CASH FLOWS RELATING TO PROVED OIL AND GAS RESERVES

Years Ended December 31, 2018 and 2017

(Unaudited)

	As of December 31,	
(Thousands of dollars)	**2018**	**2017**
Future cash inflows	$ 518,783	$ 384,198
Future production costs	(253,896)	(175,099)
Future development costs	(24,584)	(34,798)
Future income tax expenses	(38,589)	(20,884)
Future Net Cash Flows	201,714	153,417
10% annual discount for estimated timing of cash flows	(63,805)	(46,503)
Standardized Measure of Discounted Future Net Cash Flows	$ 137,909	$ 106,914

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, 2018 and 2017

(Unaudited)

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2018 and 2017:

(Thousands of dollars)	Year Ended December 31, 2018	2017
Sales of oil and gas produced, net of production costs	$ (22,065)	$ (36,003)
Net changes in prices and production costs	24,826	12,432
Extensions, discoveries and improved recovery	46,885	76,694
Revisions of previous quantity estimates	1,942	19,808
Net change in development costs	3,062	(5,199)
Reserves sold	(274)	(21)
Reserves purchased	971	1,372
Accretion of discount	10,691	5,224
Net change in income taxes	(17,704)	(13,001)
Changes in production rates (timing) and other	(17,339)	(6,627)
Net change	30,995	54,677
Standardized measure of discounted future net cash flow:		
Beginning of year	106,914	52,237
End of year	$ 137,909	$ 106,914

See accompanying Notes to Supplementary Information

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PRIMEENERGY RESOURCES CORPORATION AND SUBSIDIARIES

SUPPLEMENTARY INFORMATION

RESERVE QUANTITY INFORMATION

Years Ended December 31, 2018 and 2017

(Unaudited)

	As of December 31,					
	2018			2017		
	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)
Proved Developed Reserves:						
Beginning of year	5,333	1,704	17,143	3,107	1,265	13,001
Extensions, discoveries and improved recovery	1,389	511	2,832	2,263	488	3,253
Revisions of previous estimates	192	662	4,144	496	89	3,846
Converted from undeveloped reserves	605	258	870	383	103	476
Reserves sold	(3)		(368)	(2)		(13)
Reserve purchased	75	35	179	90	41	220
Production	(1,187)	(463)	(3,735)	(1,004)	(282)	(3,640)
End of year	6,404	2,707	21,065	5,333	1,704	17,143
Proved Undeveloped Reserves:						
Beginning of year	505	156	709	643	159	2,003
Extensions, discoveries and improved recovery	212	216	446	298	118	335
Revisions of previous estimates	(102)	(102)	(161)	(53)	(18)	(1,153)
Converted to developed reserves	(605)	(258)	(870)	(383)	(103)	(476)
End of year	10	12	124	505	156	709
Total Proved Reserves at the End of the Year	6,414	2,719	21,189	5,838	1,860	17,852

RESULTS OF OPERATIONS FROM OIL AND GAS PRODUCING ACTIVITIES

Years Ended December 31, 2018 and 2017

(Unaudited)

(Thousands of dollars)	Year Ended December 31, 2018	2017
Revenue:		
Oil and gas sales	$ 93,215	$ 66,883
Costs and Expenses:		
Lease operating expenses	34,996	30,880
Depreciation, depletion and accretion	36,154	34,006
Income tax (benefit) expense	3,724	(7,753)
Total Costs and Expenses	74,874	57,133
Results of Operations from Producing Activities (excluding corporate overhead and interest costs)	$ 18,341	$ 9,750

See accompanying Notes to Supplementary Information

PRIMEENERGY RESOURCES 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.

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 2018 and 2017 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.