PRIMEENERGY RESOURCES CORP
Form 10-K/A
April 17, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K/A

(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	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**
9821 Katy Freeway, Houston, Texas	**77024**
(Address of principal executive offices)	**(Zip Code)**

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

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

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

Common Stock, par value $.10 per share

(Title of Class)

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

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

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

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

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

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

Large Accelerated Filer Accelerated Filer

Non-Accelerated Filer Smaller Reporting Company

Emerging growth company

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

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

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

This Amendment No. 1 to Form 10-K amends the Annual Report on Form 10-K of Primeenergy Resources Corporation for the year ended December 31, 2018, which was originally filed with the U.S. Securities and Exchange Commission on April 16, 2019 (the Original 10-K) is being filed to amend Item 2. Properties and Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations of the Original 10-K in order to correct drafting errors in certain data in price and production tables that were inadvertently included in the Original 10-K. All other information contained in the original Form 10-K remains unchanged.

The following items are included in this amendment:

PART I - ITEM 2. Properties

PART II - ITEM 7. Management s Discussion and Analysis of Financial Condition and Results of Operations

PART IV - ITEM 15 (b) Exhibits

In addition, as required by Rule 12b-15 under the Securities Exchange Act of 1934, new certifications by our principal executive officer and principal financial officer are filed as exhibits to this Amendment No. 1. However, because no financial statements are contained within this Amendment, we are not including new certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. This Amendment does not reflect events occurring after April 16, 2019, the date of the filing of our Original 10-K, or modify or update those disclosures that may have been affected by subsequent events. Accordingly, this Amendment No. 1 should be read in conjunction with the Original 10-K.

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PART I.

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

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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	$ 27.40	$ 23.27	$ 15.60
Average sales price per Mcf of natural gas	$ 2.23	$ 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

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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			
	Oil	NGLs	Gas	Total	Oil	NGLs	Gas	Total	Oil	NGLs	Gas	Total
As of December 31,	**(MBbls)**	**(MBbls)**	**(MMcf)**	**(MBoe)**	**(MBbls)**	**(MBbls)**	**(MMcf)**	**(MBoe)**	**(MBbls)**	**(MBbls)**	**(MMcf)**	**(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

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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

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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 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.

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Part II.

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.

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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

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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.

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

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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 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, increased an average of $4.53 per barrel or 19.5% on NGL and decreased $0.43 per Mcf, or 15.7% on natural gas during 2018 as compared to 2017.

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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.

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)	$ 8,590	$ 9,745	$ (1,155)	(11.9)%
Barrels of Natural Gas Liquids Sold	463,000	305,000	158,000	51.8%
Average Price Received	$ 27.79	$ 23.27	$ 4.53	19.5%
Natural Gas Liquids Revenue (In 000 s)	$ 12,859	$ 7,097	$ 5,762	81.2%
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	$ 1,235	$ 392

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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	$ 2.23	$ 2.73	$ (0.50)	(18.4)%
NGL Price	$ 27.40	$ 23.27	$ 4.13	17.7%

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.

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Part IV.

Item 15 (b). Exhibits
The following exhibits are filed as a part of this report:

Exhibit No.	
31.1	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	Certification of Principal Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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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.

PRIMEENERGY RESOURCES CORPORATION

Dated: April 17, 2019

By: Charles E. Drimal, Jr.
Charles E. Drimal, Jr.
Chairman, President

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