PRIMEENERGY CORP
Form 10-Q
November 19, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Quarterly Period Ended September 30, 2018

Or

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period From __________ to __________

Commission File Number 0-7406

PrimeEnergy Corporation

(Exact name of registrant as specified in its charter)

Delaware	**84-0637348**
(State or other jurisdiction of	**(I.R.S. employer**
incorporation or organization)	**Identification No.)**

9821 Katy Freeway, Houston, Texas 77024

(Address of principal executive offices)

(713) 735-0000

(Registrant s telephone number, including area code)

(Former name, former address and former fiscal year, if changed since last report)

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes No

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 number of shares outstanding of each class of the Registrant s Common Stock as November 13, 2018 was: Common Stock, $0.10 par value 2,049,478 shares.

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September 30, 2018

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PART I FINANCIAL INFORMATION

Item 1. FINANCIAL STATEMENTS

PRIMEENERGY CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS Unaudited

(Thousands of dollars)

	September 30, 2018	December 31, 2017
ASSETS		
Current Assets		
Cash and cash equivalents	$ 7,669	$ 8,438
Accounts receivable, net	14,799	16,961
Other current assets	856	1,232
Total Current Assets	23,324	26,631
Property and Equipment, at cost		
Oil and gas properties (successful efforts method), net	218,134	213,001
Field and office equipment, net	6,596	6,974
Total Property and Equipment, Net	224,730	219,975
Other Assets	149	159
Total Assets	$ 248,203	$ 246,765
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	$ 10,615	$ 24,615
Accrued liabilities	15,264	16,294
Current portion of long-term debt	948	2,378
Current portion of asset retirement	2,665	2,309
Derivative liability short-term	8,028	1,509
Due to Related Parties	30	65
Total Current Liabilities	37,550	47,170
Long-Term Bank Debt	56,577	48,459
Asset Retirement Obligations	19,828	21,269
Derivative Liability Long-Term	3,226	1,913
Deferred Income Taxes	27,325	24,962
Other Long-Term Obligations	555	553

Total Liabilities		145,061		144,326
Commitments and Contingencies				
Equity				
Common stock, $.10 par value; 2018 and 2017: Authorized: 4,000,000 shares, issued: 3,836,397 shares; outstanding 2018: 2,061,805 shares; 2017: 2,169,370 shares		383		383
Paid-in capital		8,772		8,729
Retained earnings		145,435		138,320
Treasury stock, at cost; 2018: 1,774,592 shares; 2017: 1,667,027 shares		(58,423)		(52,123)
Total Stockholders Equity PrimeEnergy		96,167		95,309
Non-controlling interest		6,975		7,130
Total Equity		103,142		102,439
Total Liabilities and Equity	$	248,203	$	246,765

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PRIMEENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS Unaudited

Three and nine months ended September 30, 2018 and 2017

(Thousands of dollars, except per share amounts)

	Three Months Ended September 30,		Nine months Ended September 30,	
	2018	**2017**	**2018**	**2017**
Revenues				
Oil sales	$ 20,960	$ 8,568	$ 57,683	$ 27,479
Natural gas sales	2,174	2,502	6,526	7,665
Natural gas liquids sales	3,890	1,534	9,588	3,901
Realized (loss) gain on derivative instruments, net	(1,349)	156	(2,925)	(49)
Field service income	4,470	4,109	13,132	12,176
Administrative overhead fees	1,414	1,530	4,344	4,758
Unrealized (loss) gain on derivative instruments, net	(2,194)	(1,262)	(8,151)	3,092
Other income	37	47	59	169
Total Revenues	29,402	17,184	80,256	59,191
Costs and Expenses				
Lease operating expense	9,533	6,762	26,867	21,058
Field service expense	3,728	3,126	10,157	9,152
Depreciation, depletion, amortization and accretion on discounted liabilities	7,883	7,812	23,715	23,821
General and administrative expense	2,250	2,523	10,761	6,878
Total Costs and Expenses	23,394	20,223	71,500	60,909
Gain on Sale and Exchange of Assets	511	359	3,168	42,078
Income (Loss) from Operations	6,519	(2,680)	11,924	40,360
Other Income (Expense)				
Interest Income	12		34	
Interest (Expense)	(834)	(594)	(2,613)	(1,659)
Income (Loss) Before Income Taxes	5,697	(3,274)	9,345	3,870
Income Taxes (Benefit) Expense	1,424	(1,384)	2,332	12,407
Net (Loss) Income	4,273	(1,890)	7,013	26,294
Less: Net Income (Loss) Attributable to Non-Controlling Interests	(80)	122	(102)	5,646
Net (Loss) Income Attributable to PrimeEnergy	$ 4,353	$ (2,012)	$ 7,115	$ 20,648

Basic (Loss) Income Per Common Share	$	2.10	$	(0.92)	$	3.38	$	9.29
Diluted (Loss) Income Per Common Share	$	1.54	$	(0.92)	$	2.49	$	6.94

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PRIMEENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF EQUITY Unaudited

Nine months ended September 30, 2018 and 2017

(Thousands of dollars)

	Common Shares	Stock Amount	Additional Paid in Capital	Retained Earnings	Treasury Stock	Total Stockholders Equity PrimeEnergy	Non-Controlling Interest	Total Equity
Balance at December 31, 2016	3,836,397	$ 383	$ 8,313	$ 96,322	$ (46,473)	$ 58,545	$ 7,335	$ 65,880
Repurchase 101,207 shares of common stock					(5,000)	(5,000)		(5,000)
Net income				20,648		20,648	5,646	26,294
Repurchase of Non-controlling interests			127			127	(187)	(60)
Distribution of Non-controlling interests							(4,410)	(4,410)
Balance at September 30, 2017	3,836,397	$ 383	$ 8,840	$ 116,970	$ (51,473)	$ 74,320	$ 8,344	$ 82,704
Balance at December 31, 2017	3,836,397	$ 383	$ 8,729	$ 138,320	$ (52,123)	$ 95,309	$ 7,130	$ 102,439
Repurchase 107,565 shares of common stock					(6,300)	(6,300)		(6,300)
Net income (loss)				7,115		7,115	(102)	7,013
Purchase of Non-controlling Interest			43			43	(53)	(10)
Balance at September 30, 2018	3,836,397	$ 383	$ 8,772	$ 145,435	$ (58,423)	$ 96,167	$ 6,975	$ 103,142

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PRIMEENERGY CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS Unaudited

Nine months ended September 30, 2018 and 2017

(Thousands of dollars)

	2018	2017
Cash Flows from Operating Activities:		
Net Income including non-controlling interest	$ 7,013	$ 26,294
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion, amortization and accretion on discounted liabilities	23,715	23,821
Gain on sale of properties	(3,168)	(42,078)
Unrealized loss (gain) on derivative instruments, net	8,151	(3,092)
Provision for deferred income taxes	2.363	10,425
Changes in operating assets and liabilities:		
Accounts receivable	2,162	(2,922)
Due to related parties	(35)	31
Other assets	376	(1,164)
Accounts payable	(14,000)	1,337
Accrued liabilities	(1,030)	8,771
Net Cash Provided by Operating Activities	25,547	21,423
Cash Flows from Investing Activities:		
Capital expenditures	(29,317)	(40,057)
Proceeds from sale of properties and equipment	2,623	46,977
Net Cash (Used in) Provided by Investing Activities	(26,694)	6,920
Cash Flows from Financing Activities:		
Purchase of stock for treasury	(6,300)	(5,000)
Purchase of non-controlling interests	(10)	(60)
Proceeds from long-term bank debt and other long-term obligations	42,800	52,000
Repayment of long-term bank debt and other long-term obligations	(36,112)	(67,521)
Distributions to non-controlling interests		(4,410)
Net Cash Provided by (Used in) Financing Activities	378	(24,991)
Net (Decrease) Increase in Cash and Cash Equivalents	(769)	3,352
Cash and Cash Equivalents at the Beginning of the Period	8,438	6,568
Cash and Cash Equivalents at the End of the Period	$ 7,669	$ 9,920
Supplemental Disclosures:		

Income taxes paid	$	4,340	$	2,588
Interest paid	$	2,761	$	1,762

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

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PRIMEENERGY CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2018

(Unaudited)

(1) Basis of Presentation:

The accompanying condensed consolidated financial statements of PrimeEnergy Corporation (PrimeEnergy or the Company) have not been audited by independent public accountants. Pursuant to applicable Securities and Exchange Commission (SEC) rules and regulations, the accompanying interim financial statements do not include all disclosures presented in annual financial statements and the reader should refer to the Company s Form 10-K for the year ended December 31, 2017. In the opinion of management, the accompanying interim condensed consolidated financial statements contain all material adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the Company s condensed consolidated balance sheets as of September 30, 2018 and December 31, 2017, the condensed consolidated results of operations, cash flows and equity for the nine months ended September 30, 2018 and 2017.

As of September 30, 2018, PrimeEnergy s significant accounting policies are consistent with those discussed in Note 1 Description of Operations and Significant Accounting Policies of its consolidated financial statements contained in PrimeEnergy s Annual Report on Form 10-K for the fiscal year ended December 31, 2017, with the exception of Accounting Standards Update (ASU) 2014-09, Revenue from Contracts with Customers (Topic 606) discussed below. Certain amounts presented in prior period financial statements have been reclassified for consistency with current period presentation. The results for interim periods are not necessarily indicative of annual results. For purposes of disclosure in the condensed consolidated financial statements, subsequent events have been evaluated through the date the statements were issued.

Recently Adopted Accounting Pronouncements

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.

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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. Early adoption is permitted; however, the Company does not intend to early adopt. 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.

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. At this time, the Company cannot reasonably estimate the financial impact this will have on its consolidated financial statements; however, the Company believes adoption and implementation of this ASU will not significantly impact its balance sheet.

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 interests of the partners and trust unit holders in the oil and gas limited partnerships (the Partnerships) and the asset and business income trusts (the Trusts) managed by the Company as general partner and as managing trustee, respectively. The Company purchased such interests in amounts totaling $10,000 and $60,000 for the nine months ended September 30, 2018 and 2017, respectively.

During the nine months ended September 30, 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 $3.0 million. During this same time period the Company acquired approximately 464 net mineral acres and working interest in 53 oil and gas wells ranging from 16.6% to 33.4%, plus one commercial salt water disposal well, for a total of $6,080,000. This acreage and group of wells are all operated by the Company and located in Reagan County, Texas, where future horizontal drilling will likely occur.

3) Additional Balance Sheet Information:

Certain balance sheet amounts are comprised of the following:

(Thousands of dollars)	September 30, 2018	December 31, 2017
Accounts Receivable:		
Joint interest billing	$ 1,873	$ 3,173
Trade receivables	2,207	941
Oil and gas sales	10,456	12,941
Other	361	4
	14,897	17,059
Less: Allowance for doubtful accounts	(98)	(98)
Total	$ 14,799	$ 16,961
Accounts Payable:		
Trade	$ 1,153	$ 14,317
Royalty and other owners	7,944	8,341
Prepaid drilling deposits	114	67
Other	1,404	1,890
Total	$ 10,615	$ 24,615
Accrued Liabilities:		
Compensation and related expenses	$ 2,387	$ 2,449
Property costs	12,092	9,141
Income Tax		4,180
Other	785	524
Total	$ 15,264	$ 16,294

(4) Property and Equipment:

Property and equipment at September 30, 2018 and December 31, 2017 consisted of the following:

(Thousands of dollars)	September 30, 2018	December 31, 2017
Proved oil and gas properties, at cost	$ 499,958	$ 476,570
Less: Accumulated depletion and depreciation	(281,824)	(263,569)
Oil and Gas Properties, Net	$ 218,134	$ 213,001

Field and office equipment	$	26,788	$	26,241
Less: Accumulated depreciation		(20,192)		(19,267)
Field and Office Equipment, Net	$	6,596	$	6,974
Total Property and Equipment, Net	$	224,730	$	219,975

(5) Long-Term Debt:

Bank Debt:

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 September 30, 2018, the Company had a total of $56.5 million of borrowings outstanding under its revolving credit facility at a weighted-average interest rate of 5.22% and $33.5 million available for future borrowings. The combined weighted average interest rate paid on outstanding bank borrowings subject to base rate and LIBO interest was 5.30% for the nine months ended September 30, 2018 as compared to 4.98% for nine months ended September 30, 2017. The Company s borrowings under this credit facility approximates fair value because the interest rates are variable and reflective of market rates.

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 September 30, 2018, the Company had a total of $1.025 million outstanding on the Additional Equipment Loans.

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

The Company determined these loans are Level 3 liabilities in the fair-value hierarchy and estimated their fair value as $922 thousand and $3.941 million at September 30, 2018 and 2017, respectively, using a discounted cash flow model.

(6) Other Long-Term Obligations and Commitments:

Operating Leases:

The Company has several non-cancelable operating leases, primarily for rental of office space, that have a term of more than one year. The future minimum lease payments for the rest of fiscal 2018 and thereafter for the operating leases are as follows:

(Thousands of dollars)	**Operating Leases**
2018	$ 133
2019	222
2020	69
2021	17
Total minimum payments	$ 441

Rent expense for office space for the nine months ended September 30, 2018 and 2017 was $396,000 and $509,000, respectively.

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Asset Retirement Obligation:

A reconciliation of the liability for plugging and abandonment costs for the nine months ended September 30, 2018 is as follows:

(Thousands of dollars)		
Asset retirement obligation	December 31, 2017	$ 23,578
Liabilities incurred		42
Liabilities settled		(1,967)
Accretion expense		840
Asset retirement obligation	September 30, 2018	$ 22,493

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.

(7) Contingent Liabilities:

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

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

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

(8) 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 September 30, 2018 and 2017, remaining options held by two key executive officers 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.

(9) 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 and Trusts. The Company purchased interests totaling $10,000 and $60,000 for the nine months ended September 30, 2018 and 2017, respectively.

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.

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(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 natural gas, crude oil price swaps and natural gas liquid 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 September 30, 2018 and December 31, 2017:

September 30, 2018	**Quoted Prices in Active Markets For Identical Assets (Level 1)**	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Balance at September 30, 2018**
(Thousands of dollars)				
Assets				
Commodity derivative contracts	$	$	$ 68	$ 68
Total assets		$	$ 68	$ 68
Liabilities				
Commodity derivative contracts	$	$	$ (11,254)	$ (11,254)
Total liabilities	$	$	$ (11,254)	$ (11.254)

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 , crude oil, natural gas liquids, 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 nine months ended September 30, 2018.

(Thousands of dollars)	
Net Liabilities December 31, 2017	$ (3,034)
Total realized and unrealized gains (losses):	
Included in earnings (a)	(11,077)
Purchases, sales, issuances and settlements	2,925
Net Liabilities September 30, 2018	$ (11,186)

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.

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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 September 30, 2018 and December 31, 2017:

		Fair Value	
(Thousands of dollars)	**Balance Sheet Location**	**September 30, 2018**	**December 31, 2017**
Asset Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Natural gas commodity contracts	Other Current Assets	$ 55	$
Natural gas liquid contracts	Other Current Assets		
Crude oil commodity contracts	Other Current Assets		344
Natural gas commodity contracts	Other Assets	13	44
Natural gas liquid contracts	Other Assets		
Total		$ 68	$ 388
Liability Derivatives:			
Derivatives not designated as cash-flow hedging instruments:			
Crude oil commodity contracts	Derivative liability short-term	(7,420)	(1,504)
Natural gas commodity contracts	Derivative liability short-term	(47)	(4)
Natural gas liquid contracts	Derivative liability short-term	(561)	
Crude oil commodity contracts	Derivative liability long-term	(3,143)	(1,910)
Natural gas commodity contracts	Derivative liability long-term		(4)
Natural gas liquid contracts	Derivative liability long-term	(83)	
Total		$ (11,254)	$ (3,422)
Total derivative instruments		$ (11,186)	$ (3,034)

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The following table sets forth the effect of derivative instruments on the consolidated statements of operations for the nine month period ended September 30, 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	$ (359)	$ 1,709
Crude oil commodity contracts	Unrealized (loss) gain on derivative instruments, net	$ (7,148)	1,383
Natural gas liquids contracts	Unrealized gain on derivative instruments, net	(645)	
Natural gas commodity contracts	Realized (loss) on derivative instruments, net	124	(130)
Crude oil commodity contracts	Realized (loss) on derivative instruments, net	(2,895)	81
Natural gas liquids contracts	Realized gain on derivative instruments, net	(154)	
		$ (11,077)	$ 3,043

(11) 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:

	Nine months Ended September 30, 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	$ 7,115	2,102,853	$ 3.38	$ 20,648	2,223,399	$ 9.29
Effect of dilutive securities: Options		754,558			750,731	
Diluted	$ 7,115	2,857,411	$ 2.49	$ 20,648	2,974,130	$ 6.94

Three Months Ended September,

	2018 Net Income (In 000 s)	2018 Weighted Average Number of Shares Outstanding	2018 Per Share Amount	2017 Net Income (In 000 s)	2017 Weighted Average Number of Shares Outstanding	2017 Per Share Amount
Basic	$ 4,353	2,069,231	$ 2.10	$ (2,012)	2,187,894	$ (0.92)
Effect of dilutive securities: Options (a)		756,366				
Diluted	$ 4,353	2,825,597	$ 1.54	$ (2,012)	2,187,894	$ (0.92)

(a) The effect of the 767,500 outstanding stock option is anti-dilutive for the three months ended September 30, 2017 due to net loss for the period.

This Report may contain statements relating to the future results of the Company that are considered forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 (the PSLRA). In addition, certain statements may be contained in the Company s future filings with the SEC, in press releases, and in oral and written statements made by or with the approval of the Company that are not statements of historical fact and constitute forward-looking statements within the meaning of the

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

Item 2. 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 Condensed Consolidated Financial Statements and the accompanying Notes to the Condensed Consolidated Financial Statements included elsewhere in this Report contain additional information that should be referred to when reviewing this material.

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 of our oil and gas properties and interests are located in the United States. Assets in our principal focus areas include mature properties with long-lived reserves and significant development opportunities as well as newer properties with development and exploration potential.

We are the operator of the majority of our developed and undeveloped acreage which is nearly all held by production. In the Permian Basin of West Texas the Company maintains an acreage position of over 20,440 gross (13,100 net) acres, approximately 95% of which is located in Reagan, Upton, Martin and Midland counties of Texas where our current horizontal drilling activity is focused. Our West Texas acreage has significant resource potential in the Spraberry and Wolfcamp reservoirs that we believe could support the drilling of as many as 400 additional horizontal wells.

In Oklahoma we maintain an acreage position of approximately 81,860 gross (10,900 net) acres. Our Oklahoma horizontal development is focused primarily in Canadian, Kingfisher, Grady, and Garvin counties. We believe approximately 2,215 net acres in these counties hold significant additional resource potential that could support the drilling of as many as 63 new horizontal wells based on an estimate of only two wells per section, with our share of such prospective future development being approximately $33.3 million based on an average 10.5% ownership level.

District Information

The following table represents certain reserve and well information as of December 31, 2017.

	Appalachian	Gulf Coast	Mid-Continent	West Texas	Other	Total
Proved Reserves as of December 31, 2017 (MBoe)						
Developed	537	803	1,774	6,742	37	9,893
Undeveloped			132	647		779
Total	537	803	1,906	7,389	37	10,672
Gross Productive Wells (Working Interest and ORRI wells)	557	322	619	566	156	2,220
Gross Productive Wells (Working Interest Only)	489	281	471	523	94	1,858
Net Productive Wells	456	174	257	516	23	1,426
Gross Operated Productive Wells	467	244	348	370	57	1,486
Gross Operated Water Disposal, Injection and Supply wells	1	8	64	7	1	81

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Reserve Information:

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

	Reserve Category											
	Proved Developed				Proved Undeveloped				Total			
As of December 31,	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe) (a)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe) (a)	Oil (MBbls)	NGLs (MBbls)	Gas (MMcf)	Total (MBoe) (a)
2015	4,579	1,673	23,275	10,131	52	12	55	73	4,631	1,685	23,330	10,204
2016	3,107	1,265	13,001	6,539	643	159	2,003	1,135	3,750	1,424	15,004	7,674
2017	5,333	1,703	17,143	9,893	505	156	710	779	5,838	1,859	17,853	10,672

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

The estimated future net revenue (using current prices and costs as of those dates) and the present value of future net revenue (at a 10% discount for estimated timing of cash flow) for our proved developed and proved undeveloped oil and gas reserves at the end of each of the three years ended December 31, 2017, are summarized as follows (in thousands of dollars):

	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
2015	$ 70,834	$ 60,962	$ 1,098	$ 233	$ 71,932	$ 61,195	$ 2,393	$ 58,802
2016	$ 56,467	$ 46,827	$ 18,114	$ 10,403	$ 74,581	$ 57,230	$ 4,993	$ 52,237
2017	$ 160,737	$ 111,614	$ 13,564	$ 6,100	$ 174,301	$ 117,714	$ 10,800	$ 106,914

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

In accordance with SEC rules governing the scheduling of the drilling of PUD reserves we have only included in our year-end reserve report the 22 PUD locations for which we have definitive plans to drill. The Company has a working interest in eight of these PUD locations and an overriding royalty interest in the remaining fourteen locations. Currently all 22 of these PUD locations have been drilled, and 20 are producing.

Our balanced portfolio of assets positions 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 flows generated from operations, through our producing oil and gas properties, our field services business, and from sales of non-core acreage.

The Company will continue to pursue the acquisition of leasehold acreage and producing properties in areas where we currently operate and believe there is additional exploration and development potential and will attempt to assume the position of operator in all such acquisitions. In order to diversify and broaden our asset base, we will consider acquiring the assets or stock in other entities and companies in the oil and gas business. Our main objective in making any such acquisitions will be to acquire income producing assets so as to build stockholder value through consistent growth in our oil and gas reserve base on a cost-efficient basis.

Our cash flows depend on many factors, including the price of oil and gas, the success of our acquisition and drilling activities and the operational performance of our producing properties. We may 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.

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Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2018, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2018 capital budget is reflective of current commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity we may adjust our capital program throughout the year, divest non-strategic assets, or enter into strategic joint ventures.

RECENT ACTIVITIES

Since the start of our West Texas horizontal drilling program in 2015 and through the 3rd quarter of 2018, the Company has participated in 64 horizontal wells in West Texas; 46 of these were completed and producing by year-end 2017, and 10 more have been brought on-line in the first nine months 2018. Of the total 64 wells drilled and producing, the Company has an average of 28% interest in 49 wells, and less than one percent interest in 15 wells. Of the 10 wells brought on production in the first nine months of 2018, three are two-mile long horizontal laterals. The Company has 38.25% interest in these three wells and invested approximately $10.1 million. As to the remaining seven wells brought on production in the first nine months of 2018, the Company has less than 1% interest. In the 3rd quarter of 2018, PrimeEnergy is participating in eight new horizontals wells, each having a one mile long lateral. The Company has 49% interest in these wells and will invest approximately $22.7 million including for production facilities. We anticipate these eight wells to be on line in the 1st quarter of 2019.

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 2,543 leasehold acres with interest between 14% and 56%, depending on the formation or depth being developed. Through the 3rd quarter of 2018, 25 wells have been drilled and completed in this joint venture, including three two-mile long horizontals completed and put on production as of July 1, 2018. In addition, the Company is participating for 49% interest in eight wells that are in the process of being drilled and completed. Apache Corporation has indicated plans to continue PAD drilling of the acreage with future phases of development expected to result in the drilling of approximately 96 additional horizontal wells at a cost of approximately $748 million in the contiguous 3900 acre block. The Company s share of these future capital expenditures would be 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 operator. Plans for the 4th quarter of 2018 include the drilling of three new horizontal wells that will develop target pay intervals other than the middle Wolfcamp. The gross drilling and completion costs for these three wells will be approximately $26 million. Prime holds between 5% and 48% working interest in various depths of this acreage and our share of these three wells will be approximately $8.5 million. With favorable results from these three wells an additional 21 wells would likely 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 960 acre block with Concho Resources. In 2016, two wells were drilled and completed and two additional wells 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.

With regard to our Oklahoma horizontal development program, which began in 2012, the Company has participated in 41 horizontal wells for approximately $35 million through September, 2018. Over this same time period the Company chose to retain an overriding royalty interest in 29 other horizontal wells that were being drilled. In the first nine months of 2018, the Company has participated in eleven wells to be completed this year at a net cost of $8.5 million. Also in the first nine months of 2018, the Company elected to retain an ORRI in 22 wells that are in the process of being drilled or completed located in various counties of central Oklahoma. In the 4th quarter of 2018 the Company anticipates participating in the drilling of six additional horizontal wells in central Oklahoma with interest of less than one percent. The horizontal activity on Company acreage in Oklahoma is primarily 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 63 new horizontal wells based on an estimate of only two wells per section with our share of the capital expenditure being approximately $33.3 million at an average 10.5% ownership level.

In the first nine months of 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 1.575% overriding royalty interest in the recompleted well. In addition, the Company successfully recompleted a shallow well in the Segno field of Polk County, Texas in which the company has a 72.5% working interest.

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RESULTS OF OPERATIONS

2018 and 2017 Compared

We reported a net income for the nine months ended September 30, 2018 of $7.1 million, or $3.38 per share and net income for the three months ended September 30, 2018 of $4.4 million, or $2.10 per share, as compared to net income of $20.6 million, or $9.29 per share and a loss of $2 million, or $(0.92) per share for the nine and three months ended September 30, 2017, respectively. Current year net income reflects an increase in production combined with commodity price changes over the three and nine months ended September 30, 2017, decrease in gains related to the sale of acreage and changes related to the valuation of derivative instruments. The significant components of income and expense are discussed below.

Oil, gas and NGLs sales increased $14.4 million, or 114.4% from $12.6 million for the three months ended September 30, 2017 to $27 million for the three months ended September 30, 2018 and increased $34.8 million, or 89% from $39 million for the nine months ended September 30, 2017 to $74 million for the nine months ended September 30, 2018.

Our realized prices at the well head increased an average of $18.04 per barrel, or 40% and $16.48 per barrel, or 35% on crude oil during the three and nine months ended September 30, 2018, respectively from the same periods in 2017. Our average price for natural gas decreased $0.24 per Mcf, or 9% and $0.55 per Mcf, or 19% during the three and nine months ended September 30, 2018, respectively from the same periods in 2017. Our average price for NGLs sold increased an average of $10.84 per barrel, or 51% and $7.27 per barrel, or 34% during the three and nine months ended September 30, 2018, respectively from the same periods in 2017.

Our crude oil production increased by 142,000 barrels or 75% from 190,000 barrels for the third quarter 2017 to 332,000 barrels for the third quarter 2018 and increased by 325,000 barrels, or 55% from 591,000 barrels for the nine months ended September 30, 2017 to 916,000 barrels for the nine months ended September 30, 2018. Our natural gas production decreased by 41,000 Mcf, or 4% from 947,000 Mcf for the third quarter 2017 to 906,000 Mcf for the third quarter 2018 and increased by 136,000 Mcf, or 5% from 2,641,000 Mcf for the nine months ended September 30, 2017 to 2,777,000 Mcf for the nine months ended September 30, 2018. Our NGL production increased by 49,000 barrels or 68% from 72,000 barrels for the third quarter 2017 to 121,000 barrels for the third quarter 2018 and increased by 152,000 barrels, or 83.5% from 182,000 barrels for the nine months ended September 30, 2017 to 334,000 barrels for the nine months ended September 30, 2018. The increase in production volumes reflect production from our Upton county horizontal wells added in late 2017 and mid 2018, offset with the natural decline of the previously existing properties.

	Nine months September 30,			
	2018	2017	Increase / (Decrease)	Increase / (Decrease)
Barrels of Oil Produced	916,000	591,000	325,000	55.0%
Average Price Received	$ 62.97	$ 46.50	$ 16.48	35.4%
Oil Revenue (In 000 s)	$ 57,683	$ 27,479	$ 30,204	109.9%
Mcf of Gas Sold	2,777,000	2,641,000	136,000	5.1%

Average Price Received	$	2.35	$	2.90	$	(0.55)	(19.0)%
Gas Revenue (In 000 s)	$	6,526	$	7,665	$	(1,139)	(14.9)%
Barrels of Natural Gas Liquids Sold		334,000		182,000		152,000	83.5%
Average Price Received	$	28.71	$	21.43	$	7.27	33.9%
Natural Gas Liquids Revenue (In 000 s)	$	9,588	$	3,901	$	5,687	145.8%
Total Oil & Gas Revenue (In 000 s)	$	73,797	$	39,045	$	34,752	89.0%

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	Three months ended September 30,			
	2018	2017	Increase / (Decrease)	Increase / (Decrease)
Barrels of Oil Produced	332,000	190,000	142,000	74.7%
Average Price Received	$ 63.13	$ 45.09	$ 18.04	40.0%
Oil Revenue (In 000 s)	$ 20,960	$ 8,568	$ 12,392	144.6%
Mcf of Gas Sold	906,000	947,000	(41,000)	(4.3)%
Average Price Received	$ 2.40	$ 2.64	$ (0.24)	(9.2)%
Gas Revenue (In 000 s)	$ 2,174	$ 2,502	$ (328)	(13.1)%
Barrels of Natural Gas Liquids Sold	121,000	72,000	49,000	68.1%
Average Price Received	$ 32.15	$ 21.31	$ 10.84	50.9%
Natural Gas Liquids Revenue (In 000 s)	$ 3,890	$ 1,534	$ 2,356	153.6%
Total Oil & Gas Revenue (In 000 s)	$ 27,024	$ 12,604	$ 14,420	114.4%

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 three and nine months ended September 2018 and 2017:

	Three Months Ended September 30,		Nine months Ended September 30,	
	2018	2017	2018	2017
	($ in thousand)			
Oil derivatives realized gains (losses)	$ (1,261)	$ 159	$ (2,895)	$ 81
Oil derivatives unrealized gains (losses)	(1,716)	(108)	(7,148)	1,383
Total gains (losses) on oil derivatives	$ (2,977)	$ 51	$ (10,043)	$ 1,464
Natural gas derivatives realized gains (losses)	$ 39	$ 19	$ 124	$ (130)
Natural gas derivatives unrealized gains (losses)	(31)	396	(359)	1,709
Total gains (losses) on natural gas derivatives	$ 8	$ 415	$ (235)	$ 1,579
NGL derivatives realized (losses)	$ (127)	$	$ (154)	$
NGL derivatives unrealized gains (losses)	(448)		(645)	
Total gains (losses) on NGL derivatives	(575)		(799)	
	$ (3,544)	$ 466	$ (11,077)	$ 3,043

Total gains (losses) on oil, natural gas and NGL derivatives

Prices received for the nine months ended September 30, 2018 and 2017, respectively, including the impact of derivatives were:

	2018	2017
Oil Price	$ 59.81	$ 46.63
Gas Price	$ 2.39	$ 2.85
NGLS Price	$ 28.24	$ 21.43

Field service income increased $0.4 million or 8.8% from $4.1 million for the third quarter 2017 to $4.5 million for the third quarter 2018 and $1.0 million, or 7.9% from $12.2 million for the nine months ended September 30, 2017 to $13.1 million for the nine months ended September 30, 2018. This increase is a combined result of increased utilization and rates charged to customers during the 2018 period. Workover rig services, hot oil treatments, salt water hauling and disposal represent the bulk of our field service operations.

Lease operating expense increased $2.8 million, or 41% from $6.8 million for the third quarter 2017 to $9.5 million for the third quarter 2018 and increased $5.8 million, or 27.6% from $21 million for the nine months ended September 30, 2017 to $26.9 million for the nine months ended September 30, 2018. This increase is primarily due to costs related to new wells brought on-line, general rate increases on vendor services and increased production taxes related to increased prices and production during the first nine months of 2018 as compared to the same period of 2017.

Field service expense increased $0.6 million or 19.3% from $3.1 million for the third quarter 2017 to $3.7 million for the third quarter 2018 and increased $1.0 million, or 19.3% from $9.2 million for the nine months ended September 30, 2017 to $10.2 million for the nine months ended September 30, 2018. Field service expenses primarily consist of salaries and vehicle operating expenses which have increased during the nine months ended September 30, 2018 over the same period of 2017 as a direct result of increased services and utilization of the equipment.

Depreciation, depletion, amortization and accretion on discounted liabilities remained flat from $7.8 million for the third quarter 2017 to $7.9 million for the third quarter 2018 and $23.8 million for the nine months ended September 30, 2017 to $23.7 million for the nine months ended September 30, 2018, reflecting the increased reserve base and production related to new wells placed on production late in 2017 and mid 2018.

General and administrative expense increased $3.9 million, or 56.5% from $6.9 million for the nine months ended September 30, 2017 to $10.8 million for the nine months ended September 30, 2018, and decreased $0.3 million, or 10.8% from $2.5 million for the three months ended September 30, 2017 to $2.25 million for the three months ended September 30, 2018. 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 $3.2 million and $42.1 million for the nine months ended September 30, 2018 and September 30, 2017, respectively consists of sales of non-essential oil and gas interests and field service equipment.

Interest expense increased from $0.6 million for the third quarter 2017 to $0.8 million for the third quarter 2018 and from $1.7 million for the nine months ended September 30, 2017 to $2.6 million for the nine months ended September 30, 2018. This increase reflects the increase in current rates and borrowings under our revolving credit agreement.

Income tax expense decreased $10.1 million due to a lower effective tax rate and lower pre-tax income. The effective tax rates for the nine months of 2018 and 2017 were 25% and 32.1%, respectively. The decrease in the effective tax rate is primarily due to the impact of the Tax Cuts and Jobs Act changes that are effective January 1, 2018.

LIQUIDITY AND CAPITAL RESOURCES

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

Net cash provided by our operating activities for the nine months ended September 30, 2018 was $25.5 million compared to $21.4 million provided by operating activities for the nine months ended September 30, 2017. Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices or changes in working capital accounts. Our oil and gas production will vary based on actual well performance but may be curtailed due to factors beyond our control.

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

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

We currently maintain a credit facility totaling $300 million, with a borrowing base of $90 million. The Company currently has $55 million in outstanding borrowings and $35million in availability under this facility. The bank reviews the borrowing base semi-annually and, at their discretion, may decrease or propose an increase to the borrowing base relative to a redetermined estimate of proved oil and gas reserves. The next borrowing base review is scheduled for December 2018. Our oil and gas properties are pledged as collateral for the line of credit and we are subject to certain financial and operational covenants defined in the agreement. We are currently in compliance with these covenants and expect to be in compliance over the next twelve months. If we do not comply with these covenants on a continuing basis, the lenders have the right to refuse to advance additional funds under the facility and 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 our ability to borrow under our revolving credit facility may be limited and we could be required to repay any indebtedness in excess of the redetermined borrowing base.

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

	Volumes			Prices		
	2018	2019	2020	2018	2019	2020
Natural Gas (MMBTU)	600,000	749,000	180,000	$ 2.97	$ 2.93	$ 2.95
Natural Gas Liquids (barrels)	18,000	60,000		$ 22.73	$ 21.66	
Oil (barrels)	71,700	540,500	100,500	$ 51.95	$ 53.53	$ 56.11

Maintaining a strong balance sheet and ample liquidity are key components of our business strategy. For 2018, we will continue our focus on preserving financial flexibility and ample liquidity as we manage the risks facing our industry. Our 2018 capital budget is reflective of current commodity prices and has been established based on an expectation of available cash flows, with any cash flow deficiencies expected to be funded by borrowings under our revolving credit facility. As we have done historically to preserve or enhance liquidity we may adjust our capital program throughout the year, divest non-strategic assets, or enter into strategic joint ventures. 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.

We have in place both a stock repurchase program and a limited partnership interest repurchase program under which we expect to continue spending during 2018. For the nine month period ended September 30, 2018, we have spent $6.3 million under these programs.

Item 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Company is a smaller reporting company and no response is required pursuant to this Item.

Item 4. CONTROLS AND PROCEDURES

As of the end of the current reported period covered by this report, the Company carried out an evaluation, under the supervision and with the participation of the Company s management, including the Company s Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company s disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the Exchange Act). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company s disclosure controls and procedures are effective with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission s rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company s internal control over financial reporting that occurred during the first nine months of 2018 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

PART II OTHER INFORMATION

Item 1. LEGAL PROCEEDINGS

None.

Item 1A. RISK FACTORS

The Company is a smaller reporting company and no response is required pursuant to this Item.

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Item 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

There were no sales of equity securities by the Company during the period covered by this report.

During the nine months ended September 30, 2018, the Company purchased the following shares of common stock as treasury shares.

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 (1)
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	214,349
Total/Average	107,565	$ 58.57	

(1) In December 1993, we announced that the Board of Directors authorized a stock repurchase program whereby we may purchase outstanding shares of the common stock from time-to-time, in open market transactions or negotiated sales. On October 31, 2012, the Board of Directors of the Company approved an additional 500,000 shares of the Company s stock to be included in the stock repurchase program. On June 13, 2018, the Board of Directors of the Company approved an additional 200,000 shares of the Company s stock to be included in the repurchase program. A total of 3,700,000 shares have been authorized, to date, under this program. Through September 30, 2018, a total of 3,484,651 shares have been repurchased under this program for $67,079,992 at an average price of $19.25 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.

Item 3. DEFAULTS UPON SENIOR SECURITIES

None

Item 4. RESERVED

Item 5. OTHER INFORMATION

None

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Item 6. EXHIBITS

The following exhibits are filed as a part of this report:

Exhibit No.	
3.1	Restated Certificate of Incorporation of PrimeEnergy Corporation (effective July 1, 2009) (Incorporated by reference to Exhibit 3.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended June 30, 2009).
3.2	Bylaws of PrimeEnergy Corporation as amended and restated as of May 20, 2015 (filed as Exhibit 3.2 of PrimeEnergy Corporation Form 8-K on May 21, 2015 and incorporated herein by reference).
10.18	Composite copy of Non-Statutory Option Agreements (Incorporated by reference to Exhibit 10.18 of PrimeEnergy Corporation Form 10-K for the year ended December 31, 2004).
10.22.5.10	Third Amended and Restated Credit Agreement dated as of February 15, 2017 among PrimeEnergy Corporation, as Borrower, Compass Bank, as Administrative Agent and Lender, Wells Fargo, National Association, as Document Agent, the Lenders Party Hereto (Compass Bank, Wells Fargo, National Association,Citibank, N.A.)and BBVA Compass Bank, as Letter of Credit Issuer and Sole Lead Arranger and Sole Bookrunner (Incorporated by reference to Exhibit 10.22.5.10 to PrimeEnergy 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 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 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).
10.22.5.11	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 Corporation Form 10-K for the year ended December 31, 2016).
10.22.5.12	Amended, Restated and Consolidated Pledge and Security Agreement dated as of February 15, 2017, among PrimeEnergy Corporation, PrimeEnergy Management Corporation, Prime Operating Company, Eastern Oil Well Service Company, Southwest Oilfield Construction Company, EOWS Midland Company and Prime Offshore L.L.C. and Compass Bank, as Administrative Agent for the Secured Parties (Incorporated by reference to Exhibit 10.22.5.12 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2016).
10.22.5.13	Amended, Restated and Consolidated Deed of Trust, Mortgage, Security Agreement, Assignment of Production and Financing Statement Dated as of May 5, 2017 (Incorporated by reference to Exhibit

	10.22.5.13 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2017).
10.22.5.14	Deed of Trust, Mortgage, Security Agreement, Assignment of Production and Financing Statement Dated as of May 5, 2017 (Incorporated by reference to Exhibit 10.22.5.14 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2017).
10.22.5.15	Amended, Restated and Consolidated Mortgage of Oil and Gas Property, Security Agreement, Assignment of Production and Financing Statement Dated as of May 5, 2017 (Incorporated by reference to Exhibit 10.22.5.15 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2017).
10.23.1	Loan and Security Agreement dated July 31, 2013, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.23.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).
10.23.2	Business Purpose Promissory Note dated July 31, 2013, made by Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company to JP Morgan Chase Bank N.A. (Incorporated by reference to Exhibit 10.23.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).
10.23.3	Guaranty dated July 31, 2013, made by PrimeEnergy Corporation in favor of JP Morgan Chase Bank, N.A. (Incorporated by reference to Exhibit 10.23.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2013).

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Exhibit No.	
10.23.4	Agreement of Equipment Substitution dated January 15, 2014, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.23.4 to PrimeEnergy Corporation Form 10-Q for the quarter ended March 31, 2014).
10.24.1	Loan and Security Agreement dated July 29, 2014, by and between JP Morgan Chase Bank, N.A. and Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company (Incorporated by reference to Exhibit 10.24.1 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2014).
10.24.2	Business Purpose Promissory Note dated July 29, 2014, made by Eastern Oil Well Service Company, EOWS Midland Company and Southwest Oilfield Construction Company to JP Morgan Chase Bank N.A. (Incorporated by reference to Exhibit 10.24.2 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2014).
10.24.3	Guaranty dated July 29, 2014, made by PrimeEnergy Corporation in favor of JP Morgan Chase Bank, N.A. (Incorporated by reference to Exhibit 10.24.3 to PrimeEnergy Corporation Form 10-Q for the quarter ended September 30, 2014).
10.25	Purchase and Sale Agreement dated as of January 25, 2017, among PrimeEnergy Corporation, PrimeEnergy Management Corporation, PrimeEnergy Operating Company, PrimeEnergy Asset and Income Fund, L.P. A-2, PrimeEnergy Asset and Income Fund, L.P. A-3, PrimeEnergy Asset and Income Fund, L.P. AA-2, and PrimeEnergy Asset and Income Fund, L.P. AA-4, as Sellers and Guidon Operating LLC, as Purchaser (Incorporated by reference to Exhibit 10.25 to PrimeEnergy Corporation Form 10-K for the year ended December 31, 2016).
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).
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 the Securities and Exchange Act of 1934, Registrant has duly caused this Report to be signed on its behalf by the undersigned thereunto duly authorized.

	PrimeEnergy Corporation (Registrant)
November 16, 2018 (Date)	/s/ Charles E. Drimal, Jr. Charles E. Drimal, Jr. President Principal Executive Officer
November 16, 2018 (Date)	/s/ Beverly A. Cummings Beverly A. Cummings Executive Vice President Principal Financial Officer