Yuma Energy, Inc.
Form 10-Q
November 14, 2014

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2014

[ ] 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: 001-32989

Yuma Energy, Inc.
(Exact name of registrant as specified in its charter)

CALIFORNIA (State or other jurisdiction of incorporation)	94-0787340 (IRS Employer Identification No.)
1177 West Loop South, Suite 1825 Houston, Texas (Address of principal executive offices)	77027 (Zip Code)

(713) 968-7000
(Registrant's telephone number, including area code)

N/A
(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 filing requirements for the past 90 days. Yes [X] 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 [X] No [ ]

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

Larger accelerated filer [ ] Accelerated filer [ ]

Non-accelerated filer [ ] (Do not check if a smaller reporting company) Smaller reporting company [X]

Indicated by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]

At November 14, 2014, 68,865,962 shares of the Registrant's Common Stock, no par value, were outstanding.

TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION
Item 1. Financial Statements.

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS

ASSETS	September 30, 2014 (Unaudited)	December 31, 2013
CURRENT ASSETS:		
Cash and cash equivalents	$9,562,262	$4,194,511
Short-term investments	1,154,281	-
Accounts receivable, net of allowance for doubtful accounts:		
Trade	9,520,345	10,837,211
Stockholder and employees	85,870	155,080
Other	991,732	417,850
Commodity derivative instruments	383,603	-
Prepayments	789,083	433,991
Deferred taxes	-	146,964
Other deferred charges	304,120	162,416
Total current assets	22,791,296	16,348,023
OIL AND GAS PROPERTIES (full cost method):		
Not subject to amortization	38,463,577	24,051,278
Subject to amortization	166,776,420	152,863,988
	205,239,997	176,915,266
Less: accumulated depreciation, depletion and amortization	(99,943,199)	(84,438,840)
Net oil and gas properties	105,296,798	92,476,426
OTHER PROPERTY AND EQUIPMENT:		
Land, buildings and improvements	2,795,000	-
Other property and equipment	3,492,904	2,066,760
	6,287,904	2,066,760
Less: accumulated depreciation and amortization	(1,922,849)	(1,822,925)
Net other property and equipment	4,365,055	243,835
OTHER ASSETS AND DEFERRED CHARGES:		
Commodity derivative instruments	548,573	818,637
Deposits	252,684	-
Receivables from affiliate	-	95,634
Goodwill	5,740,315	-
Other noncurrent assets	479,389	1,649,413

Total other assets and deferred charges	7,020,961	2,563,684
Total assets	$139,474,110	$111,631,968

The accompanying notes are an integral part of these financial statements.

3

Yuma Energy, Inc.

CONSOLIDATED BALANCE SHEETS - CONTINUED

LIABILITIES AND EQUITY	September 30, 2014 (Unaudited)	December 31, 2013
CURRENT LIABILITIES:		
Current maturities of debt	$565,166	$178,027
Accounts payable, principally trade	23,648,139	15,116,560
Commodity derivative instruments	-	677,132
Asset retirement obligations	931,154	1,755,650
Other accrued liabilities	2,390,907	1,127,283
Total current liabilities	27,535,366	18,854,652
LONG-TERM DEBT:		
Bank debt	24,965,000	31,215,000
OTHER NONCURRENT LIABILITIES:		
Preferred stock derivative liability, Series A and B	-	51,290,414
Asset retirement obligations	11,591,497	8,942,029
Commodity derivative instruments	20,849	218,649
Deferred taxes	16,181,229	13,160,205
Restricted stock units	178,922	102,532
Other noncurrent liabilities	57,677	69,998
Total other noncurrent liabilities	28,030,174	73,783,827
PREFERRED STOCK:		
Series A and B, subject to mandatory redemption	-	35,666,342
EQUITY:		
Common stock, no par value		
(300 million shares authorized, 68,865,962 and 41,074,953 issued)	133,865,431	2,669,465
Accumulated other comprehensive income	37,007	38,770
Accumulated earnings (deficit)	(74,958,868)	(50,596,088)
Total equity	58,943,570	(47,887,853)
Total liabilities and equity	$139,474,110	$111,631,968

The accompanying notes are an integral part of these financial statements.

4

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
REVENUES:				
Sales of natural gas and crude oil	$10,229,280	$5,878,954	$30,564,244	$19,431,906
Other revenue	341,819	308,092	885,455	739,584
Total revenues	10,571,099	6,187,046	31,449,699	20,171,490
EXPENSES:				
Marketing cost of sales	408,559	298,492	1,012,577	936,632
Lease operating	2,838,055	2,394,813	9,761,203	6,371,172
Re-engineering and workovers	778,628	245,528	1,330,539	1,513,767
General and administrative – stock-based compensation	521,978	17,961	598,818	427,374
General and administrative – other	2,396,780	1,224,903	7,335,901	3,814,439
Depreciation, depletion and amortization	3,865,675	3,203,017	15,604,283	7,315,103
Asset retirement obligation accretion expense	150,628	187,025	438,717	464,306
Other	55,102	136,222	83,117	127,602
Total expenses	11,015,405	7,707,961	36,165,155	20,970,395
INCOME (LOSS) FROM OPERATIONS	(444,306)	(1,520,915)	(4,715,456)	(798,905)
OTHER INCOME (EXPENSE):				
Change in fair value of preferred stock derivative liability – Series A and Series B	(11,172,928)	15,382,964	(15,676,842)	(7,581,234)
Interest expense	(114,405)	(64,076)	(321,680)	(488,788)
Other, net	2,970	(23,325)	5,634	(197,247)
Total other income (expense)	(11,284,363)	15,295,563	(15,992,888)	(8,267,269)
NET INCOME (LOSS) BEFORE INCOME TAXES	(11,728,669)	13,774,648	(20,708,344)	(9,066,174)
Income tax expense (benefit)	(576,632)	(2,040,000)	(1,710,632)	(1,998,800)
NET INCOME (LOSS)	(11,152,037)	15,814,648	(18,997,712)	(7,067,374)
PREFERRED STOCK, SERIES A AND SERIES B:				
Accretion	220,007	275,757	786,536	821,630
Dividends paid in cash	346,192	-	445,152	59,850
Dividends paid in kind	-	-	4,133,380	2,228,545
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$(11,718,236)	$15,538,891	$(24,362,780)	$(10,177,399)
EARNINGS (LOSS) PER COMMON SHARE:				

Basic	$(0.25)	$0.38	$(0.56)	$(0.25)
Diluted	$(0.25)	$0.24	$(0.56)	$(0.25)
WEIGHTED AVERAGE NUMBER OF COMMON SHARES OUTSTANDING:				
Basic	47,414,388	41,074,950	43,211,317	41,015,124
Diluted	47,414,388	64,235,086	43,211,317	41,015,124

The accompanying notes are an integral part of these financial statements.

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
NET INCOME (LOSS)	$(11,152,037)	$15,814,648	$(18,997,712)	$(7,067,374)
OTHER COMPREHENSIVE INCOME:				
Reclassification of gain on settled commodity derivatives	(7,117)	(103,210)	(2,867)	(339,266)
Less income taxes	(2,740)	(39,736)	(1,104)	(130,618)
OTHER COMPREHENSIVE INCOME (LOSS)	(4,377)	(63,474)	(1,763)	(208,648)
COMPREHENSIVE INCOME (LOSS)	$(11,156,414)	$15,751,174	$(18,999,475)	$(7,276,022)

The accompanying notes are an integral part of these financial statements.

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY

	September 30, 2014 (Unaudited)	December 31, 2013
COMMON STOCK:		
Balance at beginning of year (2013 as previously reported: 54,000 shares, $0.01 par value)	$2,669,465	$540
Retroactive effect of change to no par value upon merger closing on September 10, 2014	-	2,182,293
Retroactive effect of retirement of 54,000 Yuma Energy, Inc. shares of common stock outstanding before merger dated September 10, 2014	-	-
Retroactive effect of 40,896,221 shares issued for merger closing on September 10, 2014	-	-
Convert Series A preferred stock to 15,112,295 shares of common stock on September 10, 2014	71,028,086	-
Convert Series B preferred stock to 7,771,192 shares of common stock on September 10, 2014	36,524,852	-
Pyramid Oil Company 4,788,085 shares outstanding last day of trading September 10, 2014	22,504,000	-
Fair value of Pyramid Oil Company stock options	100,500	-
Employee restricted stock awards (178,729 shares, vested April 1, 2013, issued September 11, 2014)	-	486,632
Employee restricted stock awards (107,291 shares, vested and issued September 11, 2014)	537,528	-
Employee restricted stock awards forfeited September 8, 2014 (87,851 shares vested April 1, 2013)	-	-
Stock awards (100,000 shares) to employees, directors and consultants of Pyramid Oil Company vested upon the change in control and issued September 11, 2014	501,000	-
Balance at end of period: 68,865,962 shares for 2014 and 41,074,953 shares for 2013, no par value	133,865,431	2,669,465
CAPITAL IN EXCESS OF PAR VALUE OF COMMON STOCK:		
Balance at beginning of 2013 as previously reported	-	2,182,293
Retroactive effect of September 10, 2014 change to no par value	-	(2,182,293)
Balance at end of period	-	-
ACCUMULATED OTHER COMPREHENSIVE INCOME:		
Balance at beginning of period	38,770	268,841
Comprehensive income (loss) from commodity derivative instruments, net of income taxes	(1,763)	(230,071)

Balance at end of period	37,007	38,770
ACCUMULATED EARNINGS (DEFICIT):		
Balance at beginning of period	(50,596,088)	(10,885,832)
Net loss attributable to Yuma Energy, Inc.	(18,997,712)	(33,050,103)
Preferred stock accretion (Series A and B)	(786,536)	(1,101,972)
Preferred stock cash dividends (Series A and B)	(445,152)	(145,900)
Preferred stock dividends paid in kind (Series A and B)	(4,133,380)	(5,412,281)
Balance at end of period	(74,958,868)	(50,596,088)
TOTAL EQUITY	$58,943,570	$(47,887,853)

The accompanying notes are an integral part of these financial statements.

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Reconciliation of net loss to net cash provided by operating activities:		
Net loss	$(18,997,712)	$(7,067,374)
Increase in fair value of preferred stock derivative liability	15,676,842	7,581,234
Depreciation, depletion and amortization of property and equipment	15,604,283	7,315,103
Accretion of asset retirement obligation	438,717	464,306
Stock-based compensation net of capitalized cost	598,819	427,374
Amortization of other assets and liabilities	140,954	117,951
Deferred tax expense (benefit)	(1,710,632)	(1,998,800)
Bad debt expense	85,101	149,611
Gain on disposal of property and equipment	-	(19,500)
Write off deferred offering costs	1,257,160	-
Write off credit financing costs	-	313,652
Amortization of benefit from commodity derivatives (sold) and purchased, net	(70,313)	(54,450)
Net commodity derivatives mark-to-market gain	(921,026)	(439,478)
Other	2,057	(1,716)
Changes in current operating assets and liabilities:		
Accounts receivable	1,868,318	(634,350)
Note receivable	-	216
Other current assets	(274,235)	426,186
Accounts payable	8,024,528	7,472,589
Other current liabilities	1,007,872	951,624
Noncurrent payable to commodity derivative advisor and deferred commodity derivative premiums	(36,824)	-
NET CASH PROVIDED BY OPERATING ACTIVITIES	22,693,909	15,004,178

Yuma Energy, Inc.

CONSOLIDATED STATEMENTS OF CASH FLOWS – CONTINUED
(Unaudited)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
CASH FLOWS FROM INVESTING ACTIVITIES:		
Capital expenditures on property and equipment	$(17,901,264)	$(22,313,654)
Proceeds from sale of property	307,600	698,766
Cash received from merger	4,550,082	-
Short-term investments retired	2,142,128	-
Decrease (increase) in noncurrent receivable from affiliate	95,634	(2,493)
NET CASH USED BY INVESTING ACTIVITIES	(10,805,820)	(21,617,381)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from borrowing	901,257	872,754
Payments on borrowings	(514,118)	(613,691)
Change in borrowing on line of credit	(6,250,000)	6,740,000
Line of credit financing costs	(47,291)	(556,276)
Preparation costs to issue preferred stock	(165,034)	-
Deferred offering costs	-	(234,679)
Cash dividends to preferred stockholders (Series A and Series B)	(445,152)	(59,850)
NET CASH PROVIDED (USED) BY FINANCING ACTIVITIES	(6,520,338)	6,148,258
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	5,367,751	(464,945)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	4,194,511	5,285,022
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$9,562,262	$4,820,077
Supplemental disclosure of cash flow information:		
Interest payments (net of interest capitalized)	$210,323	$(23,569)
Interest capitalized	$767,908	$788,214
Supplemental disclosure of significant non-cash activity:		
Preferred dividends paid in kind (Series A and Series B)	$4,133,380	$2,228,545

The accompanying notes are an integral part of these financial statements.

Yuma Energy, Inc.

UNAUDITED CONDENSED NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE A – BASIS OF PRESENTATION

These consolidated financial statements are unaudited; however, in the opinion of management, they reflect all adjustments necessary for a fair statement of the results for the periods reported. All such adjustments are of a normal recurring nature unless disclosed otherwise. These consolidated financial statements, including notes, have been condensed and do not include all of the information and disclosures required by accounting principles generally accepted in the United States of America ("GAAP") for complete financial statements. These condensed consolidated financial statements should be read in conjunction with the consolidated financial statements as of and for the year ended December 31, 2013 and the notes thereto included with the Current Report on Form 8-K/A of the Company filed with the Securities and Exchange Commission ("SEC") on September 22, 2014.

On September 10, 2014, a wholly owned subsidiary of Pyramid Oil Company merged with and into Yuma Energy, Inc., a Delaware corporation ("Yuma Co."), in exchange for shares of its common stock, and Pyramid subsequently changed its name to Yuma Energy, Inc. (the "merger"). As a result of the merger, the former Yuma Co. common and preferred stockholders received approximately 66,336,701 shares or 93% of the then-outstanding common stock of Pyramid, and thus acquired voting control. Although Pyramid was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of Pyramid by Yuma Co. See Note J –Merger with Pyramid Oil Company for additional information.

NOTE B – FAIR VALUE MEASUREMENTS

Certain financial instruments are reported at fair value on the Consolidated Balance Sheets. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Yuma Energy, Inc. ("the Company") uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

Fair Value of Financial Instruments (other than Commodity Derivative, see below) – The carrying values of financial instruments, excluding commodity derivatives, comprising current assets and current liabilities approximate fair values due to the short-term maturities of these instruments.

Derivatives – The fair values of the Company's commodity derivatives are considered Level 2 as their fair values are based on third-party pricing models which utilize inputs that are either readily available in the public market, such as natural gas and oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by the Company's counterparties for reasonableness. The Company is able to value the assets and liabilities based on observable market data for similar instruments, which results in the Company using market prices and implied volatility factors related to changes in the forward curves. Derivatives are also subject to the risk that counterparties will be unable to meet their obligations. Because the Company's commodity derivative counterparty was Société Générale at September 30, 2014, the Company has not considered non-performance risk in the valuation of its derivatives.

Financial assets are considered Level 3 when their fair values are determined using pricing models, discounted cash flow methodologies or similar techniques, and at least one significant model assumption or input is unobservable. For the Company, Level 3 financial liabilities consisted of embedded derivatives related to the conversion features in the Series A Preferred Stock issued and outstanding July 1, 2011, and the Series B Preferred Stock issued and outstanding in July and August of 2012. As there was no current market for these securities, the determination of fair value required significant judgment or estimation. The Company valued the automatic conditional conversion, re-pricing/down-round, change of control, and default Series A and Series B Preferred Stock provisions using a Monte Carlo simulation model, with the assistance of an independent valuation consultant. These models incorporated transaction details such as the stock price of comparable companies in the same industry, contractual terms, maturity, and risk free interest rates, as well as assumptions about future financings, volatility, and holder behavior as of issuance, and each quarter thereafter for each of the Series A and the Series B Preferred Stock.

	Fair value measurements at September 30, 2014			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Commodity derivatives – oil	$-	$873,601	$ -	$873,601
Commodity derivatives – gas	-	58,575	-	58,575
Total assets	$-	$932,176	$ -	$932,176
Liabilities:				
Commodity derivatives – gas	$-	$20,849	$ -	$20,849
Preferred stock derivative liability	-	-	-	-
Total Liabilities	$-	$20,849	$ -	$20,849

	Fair value measurements at December 31, 2013			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Commodity derivatives – oil	$-	$818,637	$ -	$818,637
Total assets	$-	$818,637	$ -	$818,637
Liabilities:				
Commodity derivatives – gas	$-	$472,564	$ -	$472,564
Commodity derivatives – oil	-	423,217	-	423,217
Preferred stock derivative liability	-	-	51,290,414	51,290,414
Total Liabilities	$-	$895,781	$ 51,290,414	$52,186,195

Commodity derivative instruments listed above include collars, swaps, and three-way collars. For additional information on the Company's commodity derivatives, see Note C – Commodity Derivative Instruments.

At June 30, 2014 and as of the end of each of the prior quarters, level 3 inputs were used as inputs to a Monte Carlo option pricing model to calculate the value of Series A and Series B Preferred Stock and common stock. The June 30, 2014 calculation resulted in a value per share on a fully diluted and as-converted basis of $3,061. The actual simulation considered an approximate log-normal distribution for the market capital of the Company, and was estimated to evolve monthly over time (two steps per month) through February 28, 2015. At June 30, 2014, it was assumed that, in the event of a failed merger or other events, there was some modest probability that at the end of 2014 or early in 2015, the Company would either complete a Liquidity Event (as described in Note D – Stock Awards and Their Treatment) or be sold. Each simulation considered and accounted for the probability of the completion of a Liquidity Event with some probability in each half-month time period in 2014. The volatility was assumed to be 39.45% and was derived from implied volatilities of a number of public companies (tickers: AXAS, CRK, CRZO, GDP, PQ, SFY, SGY and WRES) adjusted for the Company's relatively lower amount of financial leverage at June 30, 2014.

On September 10, 2014, the value of the preferred stock and associated derivative was marked to market. The preferred stock was converted to common stock as further described in Note J – Merger with Pyramid Oil Company. With the conversion of the shares of preferred stock to common stock, the value of the associated derivative liability was marked to market, then transferred to common stock equity.

A summary of the value and the changes in the Company's assets and liabilities classified as Level 3 measurements during the periods ended September 30, 2014 and December 31, 2013 is presented below:

	Preferred Stock Derivative Liability
September 30, 2014	$-
December 31, 2013	51,290,414

Total change	$(51,290,414)

Debt – The Company's debt is recorded at the carrying amount on its Consolidated Balance Sheets. For further discussion of the Company's debt, please see Note F – Debt. The carrying amount of floating-rate debt approximates fair value because the interest rates are variable and reflective of market rates.

Asset Retirement Obligations ("AROs") – The Company estimates the fair value of AROs based on discounted cash flow projections using numerous estimates, assumptions and judgments regarding such factors as the existence of a legal obligation for an ARO, amounts and timing of settlements, the credit-adjusted risk-free rate to be used and inflation rates.

NOTE C – COMMODITY DERIVATIVE INSTRUMENTS

Objective and Strategies for Using Commodity Derivative Instruments – In order to mitigate the effect of commodity price uncertainty and enhance the predictability of cash flows relating to the marketing of the Company's crude oil and natural gas, the Company enters into crude oil and natural gas price commodity derivative instruments with respect to a portion of the Company's expected production. The commodity derivative instruments used include variable to fixed price commodity swaps, two-way and three-way collars.

The fixed price swap and two-way collar contracts entitle the Company to receive settlement from the counterparty for each calculation period in amounts, if any, by which the settlement price for the scheduled trading days applicable for each calculation period is less than the fixed strike price or floor price. The Company would pay the counterparty if the settlement price for the scheduled trading days applicable for each calculation period is more than the fixed strike price or selling price, which would be the product of the notional quantity per calculation period and the excess of the floating price over the fixed or ceiling price with respect to each calculation period. The amount payable by the counterparty, if the floating price is below the fixed or floor price, is the product of the notional quantity per calculation period and the excess of the fixed or floor price over the floating price with respect to each calculation period.

A three-way collar consists of a two-way collar contract combined with a put option contract sold by the Company with a strike price below the floor price of the two-way collar. The Company receives price protection at the purchased put option floor price of the two-way collar if commodity prices are above the sold put option strike price. If commodity prices fall below the sold put option strike price, the Company receives the cash market price plus the difference between the two put option strike prices. This type of instrument allows the Company to capture more value in a rising commodity price environment, but limits the benefits in a downward commodity price environment.

While these instruments mitigate the cash flow risk of future reductions in commodity prices, they may also curtail benefits from future increases in commodity prices.

The Company elected to discontinue hedge accounting for all commodity derivative instruments beginning with the 2013 financial year. The balance in other comprehensive income ("OCI") at year-end 2012 will remain in accumulated other comprehensive income ("AOCI") until such time that the original hedged forecasted transaction occurs. The last of these contracts will expire in December 2016. Starting with year 2013, mark-to-market adjustments to the contracts that were in AOCI at year-end 2012 will not be made to AOCI, but instead are recognized in earnings, as are all other commodity derivative contracts going forward. As a result of discontinuing the application of hedge accounting, the Company's earnings are potentially more volatile. See Note B – Fair Value Measurements for a discussion of methods and assumptions used to estimate the fair values of the Company's commodity derivative instruments.

Counterparty Credit Risk – Commodity derivative instruments expose the Company to counterparty credit risk. The Company's commodity derivative instruments are with Société Générale ("SocGen") which is rated "A" by Standard and Poor's, "A2" by Moody's, and "A" by Fitch. Commodity derivative contracts are executed under master agreements which allow the Company, in the event of default, to elect early termination of all contracts. If the Company chooses to elect early termination, all asset and liability positions would be netted and settled at the time of election.

In conjunction with certain derivative hedging activity, the Company deferred the payment of $153,389 put premiums ($128,886 in both current other deferred charges and current other accrued liabilities and $24,503 in both other noncurrent assets and other noncurrent liabilities) for production months January 2015 through December 2015. The put premium liabilities become payable monthly as the hedge production month becomes the prompt production month. The Company will begin amortizing the deferred put premium liabilities in January 2015.

Commodity derivative instruments open as of September 30, 2014 are provided below. Natural gas prices are New York Mercantile Exchange ("NYMEX") Henry Hub prices, and crude oil prices are NYMEX West Texas Intermediate, except for the oil swaps noted below that are based on Argus Light Louisiana Sweet.

	Prices are Weighted Averages		
	2014 Settlement	2015 Settlement	2016 Settlement
NATURAL GAS (MMBtu):			
3-way collars			
Volume	415,862	2,377,371	1,122,533
Ceiling sold price (call)	$ 4.35	$ 4.47	$ 4.35
Floor purchased price (put)	$ 4.07	$ 4.00	$ 4.10
Floor sold price (short put)	$ 3.30	$ 3.25	$ 3.25
Swaps			
Volume	382,570	458,622	-
Price	$ 4.05	$ 4.08	-
Reverse Swaps			
Volume	122,974	293,234	-
Price	$ 4.27	$ 4.33	-
CRUDE OIL (Bbls):			
3-way collars			
Volume	11,400	89,512	70,263
Ceiling sold price (call)	$ 103.70	$ 104.36	$ 106.39
Floor purchased price (put)	$ 90.99	$ 86.49	$ 92.38
Floor sold price (short put)	$ 69.34	$ 65.82	$ 72.38
Swaps			-
Volume	43,375	-	-
Price	$ 95.46		
Swaps with short puts			
Volume	13,500	-	-
Swap price	$ 89.34		
Floor sold price (short put)	$ 70.00	-	-
Reverse Swaps			
Volume	33,999	-	-
Price	$ 95.30	-	-
Swaps at Argus Light Louisiana Sweet			
Volume	10,453	-	-
Price	$ 99.40	-	-
Put Spread			
Volume	-	27,588	-
Floor purchased price (put)	-	$ 90.00 *	-
Floor sold price (short put)	-	$ 75.00 *	-

* Contracts include a premium to be paid by the Company of $5.56 per barrel as the contracts mature ($153,389 total premium). The premium is not included in these prices.

Derivatives for each commodity are netted on the Consolidated Balance Sheets as they are all contracts with the same counterparty. The following table presents the fair value and balance sheet location of each classification of commodity derivative contracts on a gross basis without regard to same-counterparty netting:

	Fair value as of	
	September 30, 2014	December 31, 2013
Asset commodity derivatives:		
Current assets	$1,576,732	$1,109,403
Noncurrent assets	1,617,039	2,861,225
	3,193,771	3,970,628
Liability commodity derivatives:		
Current liabilities	(1,193,129)	(1,786,535)
Noncurrent liabilities	(1,089,315)	(2,261,237)
	(2,282,444)	(4,047,772)
Total commodity derivative instruments	$911,327	$(77,144)

Sales of natural gas and crude oil on the Consolidated Statements of Operations are comprised of the following:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Sales of natural gas and crude oil	$7,821,497	$6,832,601	$31,837,566	$19,086,656
Gains (losses) realized on commodity derivatives	(223,614)	(148,436)	(2,264,661)	(148,678)
Gains (losses) unrealized on commodity derivatives	2,607,959	(823,361)	921,026	439,478
Amortized gains from benefit of sold qualified gas options	23,438	18,150	70,313	54,450
Total sales of natural gas and crude oil	$10,229,280	$5,878,954	$30,564,244	$19,431,906

A reconciliation of the components of accumulated other comprehensive income (loss) in the Consolidated Statements of Changes in Equity is presented below:

	Nine Months Ended September 30, 2014		Year Ended December 31, 2013	
	Before tax	After tax	Before tax	After tax
Balance, beginning of period	$63,041	$38,770	$437,140	$268,841
Other reclassifications due to expired contracts previously subject to hedge accounting rules	67,446	41,479	(301,499)	(185,422)
Amortized gains from benefit of sold qualified options realized in income	(70,313)	(43,242)	(72,600)	(44,649)
Balance, end of period	$60,174	$37,007	$63,041	$38,770

14

NOTE D – STOCK AWARDS AND THEIR TREATMENT

Restricted stock awards were granted in the form of restricted shares of common stock (“RSAs”) subject to a “Liquidity Event” and time-based vesting. The merger with Pyramid Oil Company that closed on September 10, 2014 was a “Liquidity Event” within the Company’s stock award agreements. This event removed that requirement for vesting, and now each award will vest in accordance with its time-based vesting schedule, typically in equal amounts per year over three years, subject to continued service as an employee or director of the Company.

A summary of the status of the RSAs and changes for the year to date ended September 30, 2014 is presented below.

	Number of Unvested RSA Shares	Weighted Average Grant-Date Fair Value
Unvested shares as of January 1, 2014	1,895,602	$3.42 per share
Granted on March 6, 2014	196,148	$3.89 per share
Granted on April 1, 2014	33,322	$3.89 per share
Granted on May 20, 2014	341,554	$3.96 per share
Vested	(107,291)	$3.08 per share
Forfeited	-	
Unvested shares as of September 30, 2014	2,359,335	$3.56 per share

Pyramid Oil Company issued stock options as compensation for non-employee members of its board of directors under the Pyramid Oil Company 2006 Equity Incentive Plan. The options vested immediately, are exercisable for a five-year period from the date of the grant.

The following is a summary of the Company’s stock option activity.

	Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value
Outstanding at December 31, 2013	105,000	$5.17	4.66	$-
Granted	-	-	-	-
Exercised	-	-	-	-
Forfeited	-	-	-	-
Outstanding at September 30, 2014	105,000	$5.17	3.91	$-
Vested and expected to vest at				
September 30, 2014	105,000	$5.17	3.91	$-
Exercisable at September 30, 2014	105,000	$5.17	3.91	$-

As of September 30, 2014, there were no unvested stock options or unrecognized stock option expenses.

The following table summarizes the information about stock options outstanding and exercisable at September 30, 2014.

	Options Outstanding			Options Exercisable	
Exercise Price	Number of Shares	Weighted-Average Remaining Life (Years)	Weighted Average Exercise Price	Number of Shares	Weighted Average Exercise Price
$5.40	5,000	1.67	$5.40	5,000	$5.40
$5.16	100,000	4.02	$5.16	100,000	$5.16
	105,000			105,000	

On April 1, 2013, the Company granted 163 Restricted Stock Units or "RSUs" to employees. Based on the exchange ratio of the merger, the RSUs converted into 123,446 RSUs. Each RSU represents a contingent right to receive one share of the Company's common stock upon vesting. In order to vest, an employee must have continuous service with the Company from time of the grant through April 1, 2016, the vesting date. The RSUs may be settled in cash and do not require the eventual issuance of common stock (although it is an election available to the Company); consequently, the awards are liability-based and the booked valuation will change as the market value for common stock changes. The Company utilized a Monte Carlo simulation option pricing model prepared by an outside consulting firm to value the RSUs from inception through June 30, 2014, and utilized a Black Scholes option pricing model prepared by an outside consulting firm at September 30, 2014. Compensation expense is recognized over the three-year vesting period.

A summary of the status of the unvested RSUs and changes during the nine months ended September 30, 2014 is presented below.

	Number of Unvested RSUs	Weighted average grant-date fair value
Unvested shares as of January 1, 2014	119,659	$2.72 per share
Forfeited	(24,235)	$2.72 per share
Unvested shares as of September 30, 2014	95,424	$2.72 per share

NOTE E – EARNINGS PER COMMON SHARE

Earnings per common share are computed by dividing earnings available to common stockholders by the weighted average number of shares of common stock outstanding during the period. Potential common stock equivalents are determined using the "if converted" method.

Potentially dilutive securities for the computation of diluted weighted average shares outstanding are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013

Series A Preferred Stock	11,662,749	13,719,925	13,411,550	12,708,122
Series B Preferred Stock	5,997,333	7,359,805	7,037,394	7,224,242
Restricted Stock Awards	2,443,318	1,958,475	2,227,892	1,145,094
Restricted Stock Units	101,104	121,931	109,086	82,550
	20,204,504	23,160,136	22,785,922	21,160,008

The Series A and Series B Preferred Stock was converted to common stock on September 10, 2014, 71 days into the total 92 days for the three month period ended September 30, 2014. This shorter period accounts for the decrease in weighted average number of shares in the three months ended September 20, 2014 compared to the same period in 2013.

The Company excludes preferred stock and stock-based awards whose effect would be anti-dilutive from the calculation. For the three month period ended September 30, 2014 and the nine month periods ended September 30, 2014 and 2013, adjusted earnings were losses, therefore common stock equivalents were excluded from the calculation of diluted net loss per share of common stock, as their effect was anti-dilutive.

NOTE F – DEBT

	September 30, 2014	December 31, 2013
Variable rate revolving credit facility payable to Société Générale, OneWest Bank, FSB, and View Point Bank, N.A., maturing May 20, 2017, secured by oil and natural gas properties held by Yuma Exploration and Production Company, Inc. and guaranteed by The Yuma Companies, Inc.	$24,965,000	$31,215,000
Installment loan due February 28, 2015, originating from the financing of insurance premiums at 3.65% interest rate.	565,166	178,027
	25,530,166	31,393,027
Less: current portion	(565,166)	(178,027)
Total long-term debt	$24,965,000	$31,215,000

On February 13, 2013, the credit agreement was amended to bring SocGen in as a new participant and as a replacement for Union Bank N.A. ("Union") as the Administrative Agent, and to remove Amegy from the syndication (although still remaining as the Company's bank for operations). The participation allocation became 68.75% for SocGen and 31.25% for Union. The interest rate margins effective February 13, 2013, are as follows:

Borrowing base utilization	Prime margin	LIBOR margin
Utilization ≥ 90%	2.25 %	3.25 %
75% ≤ utilization < 90%	2.00 %	3.00 %
50% ≤ utilization < 75%	1.75 %	2.75 %
25% ≤ utilization < 50%	1.50 %	2.50 %
Utilization < 25%	1.25 %	2.25 %

On May 20, 2013, a third amendment to the credit agreement brought in OneWest Bank, FSB ("OneWest") to replace Union with new participation equal for SocGen and OneWest at 50/50. With the new amendment, the credit agreement matures on May 20, 2017.

On September 27, 2013, the Borrowing Base Redetermination Agreement and Assignment brought in View Point Bank, N.A. ("View Point") as a third lender in the credit agreement. Participating percentages at September 27, 2013 became 37.5% for SocGen, 37.5% for OneWest and 25% for View Point.

Effective April 22, 2014, Yuma Exploration and Production Company, Inc., a Delaware corporation and wholly owned subsidiary of the Company ("Exploration"), entered into the fourth amendment to the credit agreement, which among other things, provides for a borrowing base of $40 million, and an additional non-conforming borrowing base over and above the conforming base of $4.5 million (which expired October 15, 2014). The unamortized Amegy and Union costs of $123,925 and $189,727 were written off immediately upon their exit from the syndicate.

The following summarizes interest expense for the three and nine month periods ended September 30, 2014 and 2013.

	Three Months Ended September 30,	Nine Months Ended September 30,

	2014	2013	2014	2013
Credit facility	$308,486	$223,967	$889,111	$748,450
Credit facility commitment fees	19,133	14,140	47,209	39,053
Amortization and write offs of				
credit facility loan costs	47,715	36,436	140,955	431,603
Insurance installment loan	4,955	6,222	9,244	12,789
Louisiana Mineral Board	-	32,383	-	32,383
Other interest charges	616	331	3,069	12,724
Capitalized interest	(266,500)	(249,403)	(767,908)	(788,214)
Total interest expense	$114,405	$64,076	$321,680	$488,788

The terms of the credit agreement require Exploration to meet a specific current ratio, interest coverage ratio, and a funded debt to EBITDA ratio. In addition, the credit facility requires the guarantee of The Yuma Companies, Inc., a wholly owned subsidiary of the Company. Exploration was in compliance with the loan covenants as of September 30, 2014.

NOTE G – INCOME TAXES

The following summarizes the income tax expense (benefit) and effective tax rates:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Consolidated net income (loss) before income taxes	$(11,728,669)	$13,774,648	$(20,708,344)	$(9,066,174)
Income tax expense (benefit)	(576,632)	(2,040,000)	(1,710,632)	(1,998,800)
Effective tax rate	5%	(15%)	8%	22%

The differences between the U.S. federal statutory rate of 35% and the Company's effective tax rates for the three and nine month periods ended September 30, 2014 and 2013 are due primarily to the tax effects of the excess of book basis over the tax basis in the full cost pool, net operating loss carryforwards, and the nondeductible changes in fair value of preferred stock derivative liability for each period.

The Company knows of no uncertain tax positions and has no unrecognized tax benefits for the nine months ended September 30, 2014 or September 30, 2013. When the Company believes that it is more likely than not that a net operating loss or credit may expire unused, it establishes a valuation allowance against that loss or credit. No valuation allowance has been established as of September 30, 2014 or September 30, 2013.

NOTE H – PAYMENT OF PREFERRED DIVIDENDS

On September 15, 2014, the Company made the final cash dividend payment to the holders of record of the Series A and Series B Preferred Stock. The amount of the preferred stock dividends paid were as follows:

Series A Preferred Stock Dividends	$214,903
Series B Preferred Stock Dividends	131,289
Total Dividends	$346,192

NOTE I – CONTINGENCIES

1. Certain Legal Proceedings

From time to time, the Company is party to various legal proceedings arising in the ordinary course of business. While the outcome of lawsuits cannot be predicted with certainty, the Company is not currently a party to any proceeding that it believes, if determined in a manner adverse to the Company, could have a potential material adverse effect on the Company's financial condition, results of operations, or cash flows.

On July 9, 2014, Nabors Drilling USA, L.P. and other Nabors entities and Exploration and other Yuma entities were named in a lawsuit filed in the District Court of Harris County, Texas, in the 80th Judicial District, concerning the death of an employee of Timco Services during the drilling of the Crosby 12-1 well. The Company has tendered its defense to its liability insurance carriers who are responding. Management believes that the Company has adequate insurance to meet this potential claim.

2. Environmental Remediation Contingencies

As of September 30, 2014, there were no known environmental or other regulatory matters related to the Company's operations that were reasonably expected to result in a material liability to the Company. The Company's operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection.

Exploration has been named as one of 97 defendants in a matter entitled Board of Commissioners of the Southeast Louisiana Flood Protection Authority – East, Individually and As the Board Governing the Orleans Levee District, the Lake Borgne Basin Levee District, and the East Jefferson Levee District v. Tennessee Gas Pipeline Company, LLC, et al., Civil District Court for the Parish of Orleans, State of Louisiana, No. 13-6911, Division "J" - 5, now removed as Civil Action No. 13-5410, before the United Stated District Court, Eastern District of Louisiana. Plaintiff filed the suit on July 24, 2013 seeking damages and injunctive relief arising out of defendants' drilling, exploration, and production activities from the early 1900s to the present day in coastal areas east of the Mississippi River in Southeast Louisiana.

The suit alleges that defendants' activities have caused "removal, erosion, and submergence" of coastal lands resulting in significant reduction or loss of the protection such lands afforded against hurricanes and tropical storms. Plaintiff alleges that it now faces increased costs to maintain and operate the man-made hurricane protection system and may reach the point where that system no longer adequately protects populated areas.

Plaintiff lists hundreds of wells, pipelines, and dredging events as possible sources of the alleged land loss. Exploration is named in association with 11 wells, four rights-of-way, and one dredging permit. The suit does not specify any deficiency or harm caused by any individual activity or facility.

Although the suit references various federal statutes as sources of standards of care, plaintiff claims that all causes of action arise under state law: negligence, strict liability, natural servitude of drain, public nuisance, private nuisance, and as third-party beneficiary under breach of contract.

The Company has tendered its defense to its liability insurance carriers who are responding. At this time, the Company cannot predict the outcome of this case or, in management's opinion, assess any potential liability; therefore no liability has been recorded on the Company's books.

NOTE J – MERGER WITH PYRAMID OIL COMPANY

On September 10, 2014, a wholly owned subsidiary of Pyramid Oil Company merged with and into Yuma Energy, Inc., a Delaware corporation ("Yuma Co."), in exchange for 66,336,701 shares of common stock and the Company changed its name to "Yuma Energy, Inc." (the "merger"). As a result of the merger, the former Yuma Co. stockholders received approximately 93% of the then outstanding common stock of the Company and thus acquired voting control. Although the Company was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of the Company by Yuma Co. The transaction is expected to qualify as a tax-deferred reorganization under Section 368(a) of the Internal Revenue Code of 1986, as amended (the "Code").

As a result of the merger announcement with Pyramid Oil Company on February 6, 2014, expenses of approximately $1.3 million incurred by the Company associated with exploring options to obtain a public listing were written off during the first quarter of 2014.

The merger was accounted for as a business combination in accordance with Accounting Standards Codification ("ASC") No. 805 "Business Combinations" ("ASC 805"). ASC 805, among other things, requires assets acquired and liabilities assumed to be measured at their acquisition date fair values.

A table of adjustments reflecting the allocation of the fair values and computation of goodwill is provided below. These adjustments reflect the elimination of the components of Pyramid's historical stockholders' equity, the estimated value of consideration paid by Yuma in the merger using the closing price of common stock on September 10, 2014 and the adjustments to the historical book values of Pyramid's assets and liabilities to their estimated fair values, in accordance with acquisition accounting. The evaluation of the assigned fair values is ongoing, as the transaction was recently completed. The Company expects the purchase price allocation will be finalized in the fourth quarter of 2014. The Company believes these estimates are reasonable and the significant effects of the merger are properly reflected.

Purchase Price(i):	
Shares of Pyramid common stock held by Pyramid stockholders	4,788,085
Pyramid common stock price (September 10, 2014 closing)	$4.70
Fair value of Pyramid common stock issued	$22,504,000
Consideration to be paid to Pyramid's stockholders	-
Issuance of 100,000 shares to Pyramid affiliated persons at $5.01 per share (September 11, 2014 closing)	501,000
Fair value of Pyramid options assumed by Yuma(iv)	100,500
Total purchase price	$23,105,500
Estimated Fair Value of Liabilities Assumed:	
Current liabilities	$633,917
Long-term deferred tax liability(ii)	4,879,724
Other non-current liabilities (asset retirement obligation)	1,334,278
Amount attributable to liabilities assumed	6,847,9191
Total purchase price plus liabilities assumed	29,953,419
Estimated Fair Value of Assets Acquired:	
Current assets	9,066,589
Natural gas and oil properties(iii)	10,726,715
Net other operating property and equipment	4,158,420
Other non-current assets	261,380
Amount attributable to assets acquired	24,213,104
Goodwill(i)	$5,740,315

(i) Under the terms of the merger agreement, Pyramid stockholders own 7% of the combined entity. The total purchase price is based upon the closing price of $4.70 per share of Pyramid common stock on September 10, 2014 and 4,788,085 shares of Pyramid common stock outstanding at the effective time of the merger. The difference between the purchase price plus the liabilities of Pyramid assumed in the merger less the estimated fair value of the Pyramid assets acquired is shown as goodwill.

(ii) Yuma received a carryover tax basis in Pyramid's assets and liabilities because the merger was not a taxable transaction under the Internal Revenue Code of 1986, as amended (the "Code"). Based upon the preliminary purchase price allocation, a step-up in financial reporting carrying value related to the property acquired from Pyramid, net of the existing Pyramid deferred tax asset of $0.5 million, is expected to result in a combined deferred tax liability of approximately $16.2 million, an increase of approximately $5.4 million to the Company's and Pyramid's existing $10.8 million net deferred tax liability.

(iii) Weighted average commodity prices utilized in the determination of the fair value of natural gas and oil properties was based on the NYMEX price forecasts as of August 29, 2014 for oil and September 2, 2014 for natural gas, adjusted for differentials calculated from the 2013 historic Pyramid oil and gas prices versus the NYMEX oil (WTI) and gas average monthly prices, after adjustment for transportation fees.

(iv) To adjust for the outstanding stock options to purchase common stock that were assumed by Yuma with the merger. The $100,500 fair value of the assumed options was calculated using the Black Scholes valuation model with assumptions for the following variables: common stock price, risk-free interest rates, and the Company's stock volatility.

The following unaudited pro forma combined results of operations are provided for the nine month periods ended September 30, 2014 and 2013 as though the merger had been completed as of the beginning of the earliest period presented, or January 1, 2013. These pro forma combined results of operations have been prepared by adjusting the historical results of the Company to include the historical results of Pyramid. These supplemental pro forma results of operations are provided for illustrative purposes only, and do not purport to be indicative of the actual results that would have been achieved by the combined company for the periods presented or that may be achieved by the combined company in the future. The pro forma results of operations do not include any cost savings or other synergies that resulted, or may result, from the merger or any estimated costs that will be incurred to integrate Pyramid. Future results may vary significantly from the results reflected in this pro forma financial information because of future events and transactions, as well as other factors.

	Nine Months Ended September 30,	
	2014	2013
Revenues	$34,352,101	$23,472,140
Net loss from operations	$(18,700,021)	$(7,765,019)
Net loss per share:		
Basic	$(.27)	$(.18)
Diluted	$(.27)	$(.18)

For the three and nine month periods ended September 30, 2014, the Company recognized $214,052 of sales of natural gas and crude oil less lease operating expenses, production taxes and other operating expenses of $229,767 related to properties acquired in the merger. Additionally, non-recurring transaction costs of $856,840 and $1,442,115 related to the merger for the three and nine month periods ended September 30, 2014, respectively, are included in the Consolidated Statements of Operations as general and administrative expenses; however, these non-recurring transaction costs have been excluded from the pro forma results in the above table.

NOTE K – GOODWILL

During the third quarter of 2014, the Company recorded $5,740,315 of goodwill as a result of the merger. Goodwill represents the excess of the purchase price over the estimated fair value of the net assets acquired in the acquisition of a business. Goodwill is not amortized; rather, it is tested for impairment both annually and when events or changes in circumstances indicate that fair value of a reporting unit with goodwill has been reduced below carrying value. The impairment test requires allocating goodwill and other assets and liabilities to reporting units. However, the Company has only one reporting unit. To assess impairment, the Company has the option to qualitatively assess if it is more likely than not that the fair value of the reporting unit is less than the book value. Absent a qualitative assessment, or, through the qualitative assessment, if the Company determines it is more likely than not that the fair value of the reporting unit is less than the book value, a quantitative assessment is prepared to calculate the fair market value of the reporting unit. If it is determined that the fair value of the reporting unit is less than the book value, the recorded goodwill is impaired to its implied fair value with a charge to operating expense.

The assumptions the Company will use in calculating its reporting unit fair value at the time of the test include its market capitalization and discounted future cash flows based on estimated reserves and production, future costs and future oil and natural gas prices. Material adverse changes to any of these factors could lead to an impairment of all or a portion of the Company’s goodwill in future periods.

NOTE L – SUBSEQUENT EVENTS

The Company has evaluated subsequent events through November 14, 2014, the date these financial statements were available to be issued. The Company is not aware of any subsequent events which would require recognition or disclosure in the financial statements, except as noted below or already recognized or disclosed in the Company’s filings with the SEC.

1. Issuance of Series A Preferred Stock

On October 23, 2014, the Company held an initial closing of its public offering of 9.25% Series A Cumulative Redeemable Preferred Stock, no par value per share, with a liquidation preference of $25.00 per share (the “Series A Preferred Stock”). The Company issued 477,273 shares at a public offering price of $22.00 per share, for gross proceeds of $10,500,006. On October 24, 2014, the Company held an additional closing for 30,466 shares of Series A Preferred Stock at a public offering price of $22.00 per share for gross proceeds of $670,252. In total, the Company received $10,430,894 net of the underwriters discount and underwriters' expenses. In addition to fees at the time of closing, the Company incurred estimated costs of $351,034 for the preferred stock issuance. The shares of Series A Preferred Stock trade on the NYSE MKT under the symbol "YUMAprA". The Series A Preferred Stock cannot be converted into common stock of the Company (except upon a change in control and in the event the Company chooses to not redeem the Series A Preferred Stock), but may be redeemed by the Company, at the Company's option, on or after October 23, 2017 (or in certain circumstances, prior to such date as a result of a change in control of the Company), at a redemption price of $25.00 per share plus any accrued and unpaid dividends. The Series A Preferred Stock has no stated maturity, is not subject to any sinking fund or mandatory redemption, and will remain outstanding indefinitely unless repurchased, redeemed or converted into common stock in connection with a change in control. Holders of the Series A Preferred Stock are entitled to receive, when, as and if declared by the Company's board of directors, cumulative dividends at the rate of 9.25% per annum (the dividend rate) on the redemption price of $25.00 per share of the Series A Preferred Stock, payable monthly in arrears on each dividend payment date, with the first payment date of December 1, 2014.

2. Fifth Amendment to Loan Agreement

On October 14, 2014, the Company entered into the Fifth Amendment to its Credit Agreement with SocGen as Agent Bank and two other banks. Although the Fifth Amendment restates many of the same terms from earlier revisions, it provides for the payment of dividends to the holders of Series A Preferred Stock under the following conditions:

The borrowing base utilization percentage is 90% or less giving effect for the dividend payment;

No default has occurred and will not occur with the dividend payment;

All dividend payments need to be made in accordance with the Certificate of Determination or other agreements governing the Series A Preferred Stock.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the accompanying unaudited consolidated financial statements and related notes thereto, included in Part I, Item 1 of this Quarterly Report on Form 10-Q and should further be read in conjunction with our Annual Report on Form 10-K, as amended, for the year ended December 31, 2013, and our Current Report on Form 8-K/A filed on September 22, 2014.

Cautionary Statement about Forward-Looking Statements

Certain statements contained in this report may contain "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical facts contained in this report are forward-looking statements. These forward-looking statements can generally be identified by the use of words such as "may," "will," "intends," "plans," "believes," "anticipates," "expects," "estimates," "predicts," "po negative of these words or similar expressions. Statements that describe our future plans, strategies, intentions, expectations, objectives, goals or prospects are also forward-looking statements. Readers should consider carefully the risks described under the "Risk Factors" section included in Part II, Item 1A of this Quarterly Report on Form 10-Q and in our previously filed Annual Report on Form 10-K for the fiscal year ended December 31, 2013, and the other disclosures contained herein and therein, which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

our ability to successfully integrate acquired oil and natural gas businesses and operations;

the possibility that acquisitions and divestitures may involve unexpected costs or delays, and that acquisitions may not achieve intended benefits and will divert management's time and energy, which could have an adverse effect on our financial position, results of operations, or cash flows;

risks in connection with potential acquisitions and the integration of significant acquisitions;

we may incur more debt; higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business;

our ability to successfully develop our large inventory of undeveloped acreage in our resource plays;

access to adequate gathering systems, processing facilities, transportation take-away capacity to move our production to market and marketing outlets to sell our production at market prices, which is necessary to fully execute our capital program;

our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fund our operations, satisfy our obligations and fully develop our undeveloped acreage positions;

volatility in commodity prices for oil and natural gas;

our ability to replace our oil and natural gas reserves;

the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;

the potential for production decline rates for our wells to be greater than we expect;

our ability to retain key members of senior management and key technical employees;

environmental risks;

drilling and operating risks;

exploration and development risks;

the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulations);

general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access capital;

social unrest, political instability or armed conflict in major oil and natural gas producing regions outside the United States, such as Africa, the Middle East, and armed conflict or acts of terrorism or sabotage;

other economic, competitive, governmental, regulatory, legislative, including federal, state and tribal regulations and laws, geopolitical and technological factors that may negatively impact our business, operations or oil and natural gas prices;

the insurance coverage maintained by us may not adequately cover all losses that may be sustained in connection with our business activities;

title to the properties in which we have an interest may be impaired by title defects;

management’s ability to execute our plans to meet our goals;

the cost and availability of goods and services, such as drilling rigs; and

our dependency on the skill, ability and decisions of third party operators of the oil and natural gas properties in which we have a non-operated working interest.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this document. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Overview

Yuma Energy, Inc. (the “Company”) is a U.S.-based oil and gas company focused on the exploration for, and development of, conventional and unconventional oil and gas properties, primarily through the use of 3-D seismic surveys, in the U.S. Gulf Coast and California. The Company has employed a 3-D seismic-based strategy to build a multi-year inventory of development and exploration prospects. The Company’s current operations are focused on onshore central Louisiana, where the Company is targeting the Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex and Hackberry formations. In addition, the Company has a non-operated position in the Bakken Shale in North Dakota and operated positions in Kern and Santa Barbara Counties in California. As a result of the merger with Pyramid Oil Company (see Item 1. Unaudited Condensed Notes to the Consolidated Financial Statements, Note J – Merger With Pyramid Oil Company), the Company underwent a substantial change in ownership, management, assets and business strategy, all effective as of September 10, 2014. Our common stock is traded on the NYSE MKT under the trading symbol “YUMA.” Our Series A Preferred Stock is traded on the NYSE MKT under the trading symbol “YUMAprA.”

Recent Developments

Merger – Change in Management, Control and Business Strategy

On September 10, 2014, a wholly owned subsidiary of the Company merged with and into Yuma Energy, Inc., a Delaware corporation (“Yuma Co.”), in exchange for 66,336,701 shares of common stock and the Company changed its name to “Yuma Energy, Inc.” (the “merger”). As a result of the merger, the former Yuma Co. stockholders received approximately 93% of the then outstanding common stock of the Company and thus acquired voting control. Although the Company was the legal acquirer, for financial reporting purposes the merger was accounted for as a reverse acquisition of the Company by Yuma Co.

Subsequent to the merger, Sam L. Banks assumed the role of Chairman, President and Chief Executive Officer, Kirk F. Sprunger became Chief Financial Officer, Treasurer and Corporate Secretary, and Paul D. McKinney became Executive Vice President and Chief Operating Officer. Our board of directors was reconstituted to include the directors of Yuma Co., Sam L. Banks, James W. Christmas, Frank A. Lodzinski, Ben T. Morris, Richard K. Stoneburner, and Richard W. Volk. Also, as part of the merger, our headquarters were relocated to Houston, Texas.

Series A Preferred Stock Offering

On October 23 and 24, 2014, the Company closed a public offering of 507,739 shares of its 9.25% Series A Cumulative Redeemable Preferred Stock, no par value per share, with a liquidation preference of $25.00 per share (the “Series A Preferred Stock”), at a public offering price of $22.00 per share, with aggregate net proceeds of $10,555,893, net of the underwriters discount and underwriters’ expenses.

Business Strategy

Our business strategy is to achieve long-term growth in production and cash flow on a cost-effective basis. We focus on maximizing our return on capital employed and adding production and reserves through the development of our Austin Chalk, Tuscaloosa, Wilcox, Frio, Marg Tex, Hackberry, Bakken, Three Forks, and Monterey Shale acreage.

Several of the key elements of our business strategy are as follows:

- transition existing inventory of reserves into oil and natural gas production;
- add to project inventory through ongoing prospect generation, exploration and strategic acquisitions;
- acquire additional working interests within drilling units in existing operated proved undeveloped locations; and
- retain a greater percentage working interest in, and operatorship of, our projects going forward

Our core competencies include generating:

- unconventional oil resource plays;
- onshore liquids-rich projects through the use of 3-D seismic surveys; and
- identification of high impact deep onshore prospects located beneath known producing trends through the use of 3-D seismic surveys.

Our Key Strengths and Competitive Advantages

Extensive technical knowledge and history of operations in the Gulf Coast region. Since 1983 Yuma Co. or its predecessor has operated in the Gulf Coast region, which is an area that extends through Texas, Louisiana and Mississippi. Our extensive understanding of the geology and experience in interpreting well control, core and 3-D seismic data in this area provides us with a competitive advantage in exploring and developing projects in the Gulf Coast region. We have cultivated amicable and mutually beneficial relationships with acreage owners in this region and adjacent oil and gas operators, which generally provides for effective leasing and development activities.

In-house technical expertise in 3-D seismic programs. We design and generate in-house 3-D seismic survey programs on many of our projects. By controlling the 3-D seismic program from field acquisition through seismic processing and interpretation, we gain a competitive advantage through proprietary knowledge of the project.

Liquids-rich, quality assets with attractive economics. Our reserves and drilling locations are primarily oil plays with associated liquids-rich natural gas.

Diversified portfolio of producing and non-producing assets. Our current portfolio of producing and non-producing assets covers a large area within the U.S. Gulf Coast, the Bakken/Three Forks shale in North Dakota, and Kern and Santa Barbara Counties in California.

Significant inventory of oil and gas assets. We have a significant inventory of both proved reserves and significant growth assets that we believe can be developed over the near to medium term. In addition, we have the ability to organically generate new oil and gas prospects and projects through techniques utilized by our experienced management team, which include (1) analyzing subsurface data and 2-D seismic data to identify areas where a 3-D seismic survey could be acquired for the generation of oil and gas prospects, (2) negotiating mineral rights with large landowners in prospective areas, and (3) reprocessing of older 3-D seismic surveys utilizing new technology. Once these techniques are applied, the technical team surveys prospective areas for new oil and gas deposits and what methods might be employed to identify those likely locations. In recent years, the predominant method used has been to conduct 3-D seismic surveys. Once a survey has been acquired, the team evaluates the seismic data.

Company operated assets. In order to maintain better control over our assets, we have established a leasehold position comprised primarily of assets where we are the operator. By controlling operations, we are able to dictate the pace of development and better manage the cost, type, and timing of exploration and development activities.

Experienced management team. We have a highly qualified management team with many years of industry experience, including extensive experience in the Gulf Coast region. Our team has substantial expertise in the design, acquisition, processing and interpretation of new 3-D seismic surveys, and our experienced operations staff allows for efficient turnaround from project identification to drilling to production.

Experienced board of directors. Our directors have substantial experience managing successful public companies and realizing value for investors through the development, acquisition and monetization of both conventional and unconventional oil and gas assets in the Gulf Coast region.

Overview of Third Quarter 2014 Results

For the three months ended September 30, 2014, production averaged 1,646 Boe/d compared to 1,377 Boe/d for the three months ended September 30, 2013, which represents a 19.5% increase.

For the three months ended September 30, 2014, revenues totaled $10.6 million compared to $6.2 million for the three months ended September 30, 2013, which represents a 70.0% increase.

For the three months ended September 30, 2014, our crude oil revenues were approximately $4.9 million, an increase of 2.6% compared to the three months ended September 30, 2013.

For the three months ended September 30, 2014, our gas revenues were approximately $2.1 million, an increase of 22.3% compared to the three months ended September 30, 2013.

During the third quarter of 2014, we successfully drilled and completed the Nettles 39-1 well where we hold a 32.5% working interest.

Overview of Nine Months Ended September 30, 2014

For the nine months ended September 30, 2014, production averaged 2,270 Boe/d compared to 1,110 Boe/d for the same period in 2013, representing a 104.5% increase.

For the nine months ended September 30, 2014, crude oil revenues were approximately $17.5 million, an increase of 26.5% compared to the same period in 2013.

For the nine months ended September 30, 2014, natural gas revenues were approximately $10.6 million, an increase of 200.5% compared to the nine months ended September 30, 2013.

Operational Overview

La Posada – Bayou Hebert Field, Vermilion Parish, Louisiana. We have a 12.5% working interest in La Posada. We initially generated the exploration prospect by utilizing data from a 3-D seismic survey, which resulted in a significant discovery. The primary objectives were the Lower Planulina Cris R sands, at a depth of approximately 17,700 to 18,250 feet.

The prospect was successfully tested in 2011 on the southern portion of the structure by the operator PetroQuest Energy, Inc. A brief summary of the drilling activity to date is as follows:

1. The Thibodeaux No. 1 well was drilled to a total depth of 19,079 feet and logged a net 217 feet of hydrocarbon bearing sand. The well was put on production in March 2012.

2. The Broussard No. 2 well was drilled to a depth of 19,150 feet on the north side of the structure in 2012. This well logged a net 328 feet of hydrocarbon bearing sand in the Lower Planulina Cris R-1 and Cris R-2A, B and C sandstones. The well was put on production in September 2012.

3. The Broussard No. 1 well (originally drilled and temporarily abandoned in 2007) was re-entered and sidetracked to the upper Cris R sand as an acceleration well. The Broussard No. 1 sidetrack was drilled to a depth of 18,035 feet and encountered the upper productive sand in 2013. The well was put on production in May 2013.

During the first half of 2014, the Bayou Hebert Field produced at an average rate of 106 MMcf/d of natural gas and 1,900 Bbl/d of oil. In July 2014, the Broussard No. 2 experienced an increase in water production. Although the natural gas production from the well was not affected by the increase in water, both the Broussard No. 2 and the Thibodeaux No. 1 were curtailed to avoid exceeding the water handling capability of the production facilities. Field production decreased to 45 MMcf/d of natural gas and 850 Bbl/d of oil which decreased our revenues and production for the three months ended September 30, 2014.

In September 2014, the operator reconfigured the production facilities and increased the production to approximately 53 MMcf/d of natural gas and 1,000 Bbl/d of oil. The operator has also ordered higher capacity water handling equipment that is expected to be installed in November 2014. With the installation of this additional equipment, we anticipate the field will produce between 70 MMcf/d and 75 MMcf/d of natural gas and 1,500 Bbl/d of oil starting in the fourth quarter of 2014. We also expect that during 2015, the Thibodeaux No. 1 will be recompleted from its current “C” zone to the overlying “B” zone, after which the total production from the field is expected to increase to between 95 MMcf/d and 105 MMcf/d of natural gas and 1,700 Bbl/d to 1,900 Bbl/d of oil.

Livingston Prospects, Livingston Parish, Louisiana. Our primary exploration targets which produce in the area include intermediate depth Wilcox sands and the deeper lower Tuscaloosa sands. We hold an average 33% working interest across the Livingston prospects and are the operator.

To date we have drilled five exploration wells with four discoveries on our Livingston project. Three of the wells targeted the lower Tuscaloosa sands (oil), two of which were discoveries, one well targeted the Wilcox formation (oil), and one well drilled for a shallow Miocene target (gas). The shallow Miocene well has produced out and has been shut in.

We drilled two development wells offsetting our Lower Tuscaloosa discoveries in addition to one development well offsetting our Wilcox discovery. Currently, three wells are producing from the lower Tuscaloosa sands and two wells are producing from the Wilcox. One of the Tuscaloosa wells, the Weyerhaeuser 9-1, is currently shut-in due to high water production and is being evaluated for a workover in the fourth quarter of 2014. Also, during the three months ended September 30, 2014, we had to temporarily shut in one of our Lower Tuscaloosa wells, the Weyerhaeuser 57-3, due to pumping equipment failure. The average daily production from the five remaining wells during the three months ended September 30, 2014 was 376 Boe/d gross (85 Boe/d net).

We drilled our first Wilcox discovery in 2013, the Starns 38-1, to a depth of 10,000 feet. The Starns 38-1 has produced more than 50,000 Bbls of oil and flowed between 100 Bbl/d and 115 Bbl/d during the three months ended September 30, 2014. We recently drilled the Nettles 39-1, an eastern offset to the Starns 38-1. The well was placed on production on September 5, 2014 and averaged approximately 125 Bbl/d of oil in September. The well has since cleaned up and averaged approximately 250 Bbl/d of oil during the first 10 days of November.

Plans are being made to drill the third well in this Wilcox discovery, the Blackwell 39-1. This will be an eastern offset to the Nettles 39-1, and we anticipate drilling to a depth of 10,000 feet in this Wilcox test. We plan to spud the well during the beginning of the first quarter of 2015 and, if successful, we intend to have it on production during the first quarter of 2015. Our working interest is 32.5% in each of the Starns 38-1, Nettles 39-1 and the Blackwell 39-1 wells.

In addition, we plan to drill a lower Tuscaloosa prospect, the Glacier prospect, in the Livingston 3-D seismic survey area in the first half of 2015.

Lake Fortuna Field (Raccoon Island), St. Bernard Parish, Louisiana. We discovered our Lake Fortuna field in 1996 when our 3-D Raccoon Island prospect was drilled. The target was a Middle Miocene sand on a known productive structure. In 2005, we acquired the majority of the working interest in Raccoon Island from Amerada Hess, and now own a working interest of 91%. During the three months ended September 30, 2014 we temporarily shut in a portion of the field to repair a salt water disposal well. This shut-in affected our third quarter 2014 production and revenues, but production in the field was restored to previous levels (approximately 250 Bbl/d of oil gross) after the workover was performed.

Greater Masters Creek Field, Allen, Vernon, Rapides and Beauregard Parishes, Louisiana. Our Greater Masters Creek Field properties are located in the Austin Chalk Trend in west central Louisiana. At December 31, 2013, we held approximately 76,178 net acres in the field. The acreage is located within an existing field which has previously been developed. Based on our technical analysis and independent third-party engineering, we believe there are approximately 70 operated proved undeveloped locations and 14 non-operated proved developed locations that are either held by production or leases.

We recently completed our second operated Austin Chalk well, the Crosby 14-1, which was drilled vertically to approximately 15,000 feet to the top of the Austin Chalk formation and then 3,100 feet horizontally in the Austin Chalk formation. We expect to have the well on production in approximately 30 to 45 days and hold an approximate 61% working interest in the well. We expect to spud our third Austin Chalk well in the field in 2015.

Amazon 3-D Project, Calcasieu and Jefferson Parishes, Louisiana. In 2011, we shot a 70 square mile 3-D seismic survey targeting the Frio (Hackberry and Marg Tex/Cib Haz/Camerina objectives). The Hackberry is a "bright spot" play for natural gas with rich condensate yields found in stratigraphic traps at depths of approximately 13,000 feet. The Marg Tex/Cib Haz/Camerina objectives are found at depths typically around 9,000 feet in structural traps independent of the underlying Hackberry.

We plan to drill our Anaconda prospect in the first quarter of 2015. This single well prospect is unique in that it has both Hackberry and Marg Tex objectives. The Hackberry exhibits a "bright spot" on the 3-D seismic, the attributes of which are very similar to Hackberry discoveries drilled by other operators within a mile of our location. At the Marg Tex interval, the well is anticipated to intersect four Marg Tex sands.

Cat Canyon Field, Santa Barbara, California. Our Cat Canyon field is a legacy asset that was owned by Pyramid Oil Company, prior to our merger completed on September 10, 2014. The field produces from the Monterey formation and is found at a depth of 4,500 feet and is nearly 2,000 feet thick. We have a 100% working interest in 120 acres held by production in this field. The field is surrounded by Monterey wells drilled from the late 1940's through 1982 on 10 acre spacing. The wells are drilled vertically, completed naturally (without fracing) and are put on pump immediately. We plan to drill our first operated well on this property in the first half of 2015.

Bakken – Yellowstone and Southeast Homerun. At December 31, 2013, we held an average 5% non-operated working interest in 18,513 gross acres (965 net acres) in McKenzie County, North Dakota. We have interests in six producing oil wells and two active salt water disposal wells. All producing wells are located in two fields, Yellowstone and Southeast Homerun. The majority of our interests are currently operated by Zavanna, LLC. We currently estimate that approximately 140 drilling locations remain across our Bakken asset. In addition, we believe significant future infill and Three Forks development upside potential exists on our acreage.

Critical Accounting Policies

Critical accounting policies are defined as those that are reflective of significant judgments and uncertainties and that could potentially result in materially different results under different assumptions and conditions. For a detailed description of our accounting policies, see Note B – Summary of Significant Accounting Policies in the Notes to the Consolidated Financial Statements for the period ended December 31, 2013 included as Exhibit 99.4 to our Current Report on Form 8-K/A filed with the SEC on September 22, 2014.

Sales and Other Operating Revenues

The following table presents the net quantities of oil, natural gas and natural gas liquids produced and sold by us for each of the three and nine months ended September 30, 2014 and 2013, and the average sales price per unit sold.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Production volumes:				
Crude oil and condensate (Bbl)	49,475	43,509	172,965	128,970
Natural gas (Mcf)	513,002	433,967	2,229,405	903,959
Natural gas liquids (Bbl)	16,457	10,865	77,389	23,519
Total (Boe) (1)	151,432	126,702	621,922	303,149
Average prices realized:				

Excluding commodity derivatives (both realized and unrealized)				
Crude oil and condensate (per Bbl)	$98.58	$109.25	$101.23	$107.30
Natural gas (per Mcf)	$4.04	$3.91	$4.76	$3.90
Natural gas liquids (per Bbl)	$40.73	$41.72	$41.25	$42.64
Including commodity derivatives (realized only)				
Crude oil and condensate (per Bbl)	$93.66	$101.57	$93.68	$104.99
Natural gas (per Mcf)	$4.13	$4.38	$4.36	$4.13
Natural gas liquids (per Bbl)	$40.73	$41.72	$41.25	$42.64

(1) Barrels of oil equivalent have been calculated on the basis of six thousand cubic feet (Mcf) of natural gas equal to one barrel of oil equivalent (1 Boe).

The following table presents our revenues for the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Sales of natural gas and crude oil:				
Crude oil and condensate	$4,877,227	$4,753,431	$17,508,388	$13,838,521
Natural gas	2,074,901	1,696,623	10,606,760	3,529,837
Natural gas liquids	670,267	453,262	3,192,449	1,002,775
Realized gain/(loss) on commodity derivatives	(200,176)	(130,286)	(2,194,348)	(94,228)
Unrealized gain/(loss) on commodity derivatives	2,607,959	(823,361)	921,026	439,478
Gas marketing sales	199,102	(70,715)	529,969	715,523
Other revenue	341,819	308,092	885,455	739,584
Total revenues	$10,571,099	$6,187,046	$31,449,699	$20,171,490

Sale of Crude Oil and Condensate

Crude oil and condensate are sold through month-to-month evergreen contracts. The price for Louisiana properties is tied to an index or a weighted monthly average of posted prices with certain adjustments for gravity, BS&W (Basic Sediment and Water) and transportation. Generally, the index or posting is based on WTI (West Texas Intermediate) and adjusted to LLS (Light Louisiana Sweet) or HLS (Heavy Louisiana Sweet). For the three months ended September 30, 2014 and 2013, LLS postings averaged $2.01 and $4.62 over WTI, respectively. For the nine months ended September 30, 2014 and 2013, LLS postings averaged $3.42 and $11.58 over WTI, respectively. Pricing for the California properties is based on an average of specified posted prices, adjusted for gravity, transportation, and for one field, a market differential.

Crude oil volumes increased by 13.7% for the three months ended September 30, 2014 compared to the three months ended September 30, 2013. New production from the Bertha 8-3, Crosby 12-1 and Nettles 39-1 was further enhanced by increased production from the DS&B 117, Roberts 57-1 and Starns 38-1 after successful workover operations. Increased net revenue interests on the La Posada wells were somewhat offset by reduced production of the Broussard No. 2, Thibodeaux No. 1, and Weyerhaeuser 9-1 wells. A further reduction was due to the shut-in of the Raccoon Island wells for salt water disposal well work in the three months ended September 30, 2014. A 9.8% price decrease between the three months ended September 30, 2014 and 2013 offset production increases during the quarter. The same volume-related factors in the third quarter influenced a crude oil volume increase of 34.1% for the nine months ended September 30, 2014, compared to the same period in 2013, with the La Posada net revenue interest increases having the largest impact. Realized oil prices fell 5.7% in the nine months ended September 30, 2014 compared to the nine months ended September 30, 2013.

Sale of Natural Gas and Natural Gas Liquids

Our natural gas is sold under multi-year contracts with pricing tied to either first of the month index or a monthly weighted average of purchaser prices received. Natural gas liquids are also sold under multi-year contracts usually tied to the related natural gas contract. Pricing is based on published prices for each product or a monthly weighted average of purchaser prices received.

For the three months ended September 30, 2014 compared to the same period in 2013, an 18.2% increase in natural gas volumes sold was primarily due to new production at the Crosby 12-1 and the La Posada net revenue interest increases, partially offset by the declines on the Broussard No. 2, Thibodeaux No. 1 and Weyerhaeuser 9-1 wells. During the same time period, realized natural gas prices increased by 3.3%. For the nine months ended September 30, 2014, natural gas production volumes increased 146.6% compared to the same period in 2013, with the Crosby 12-1 and the La Posada wells as the primary contributors. Average realized gas prices increased 22.1% to $4.76 per Mcf for the nine months ended September 30, 2014, from $3.90 per Mcf for the same period in 2013.

Increasing natural gas sales volumes contributed to increased natural gas liquids revenues, resulting in a 47.9% increase in NGL revenues for the three months ended September 30, 2014 over the same period in 2013, and a 218.4% increase in NGL revenues for the nine month period ended September 30, 2014 over the same period in 2013.

Gas Marketing

Gas marketing sales are natural gas volumes purchased from certain of our operated wells and the aggregated volumes sold with a mark-up of $.03 per MMBtu. Texas Southeastern Gas Marketing Company, our wholly owned subsidiary, purchases and sells natural gas on the behalf of the Company and our working interest partners.

Lease Operating Expenses

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Lease operating expenses	$2,838,055	$2,394,813	$9,761,203	$6,371,172
LOE per Boe	$18.74	$18.90	$15.70	$21.02

Lease operating expenses ("LOE") include all costs incurred to operate wells and related facilities, both operated and non-operated. In addition to direct operating costs such as labor, repairs and maintenance, equipment rentals, materials and supplies, fuel and chemicals, LOE also includes severance taxes, product marketing and transportation fees, insurance, ad valorem taxes and operating agreement allocable overhead. LOE excludes costs classified as re-engineering and workovers. If severance and ad valorem taxes were not included in the above table, LOE would have been reduced by $707,256 and $1,014,237 during the three months ended September 30, 2014 and 2013, respectively, and operating costs per barrel of oil equivalent would have been reduced to $14.07 and $10.90 for the three months ended September 30, 2014 and 2013, respectively. For the nine months ended September 30, 2014 and 2013, if severance and ad valorem taxes were not included, LOE would have been reduced by $3,026,302 and $2,153,878 respectively, and operating costs per barrel of oil equivalent would have been reduced to $10.83 and $13.91, respectively.

LOE was $2,838,055 for the three months ended September 30, 2014 compared to $2,394,813 for the same period in 2013. The 18.5% increase was primarily due to maintenance projects at Raccoon Island, Crosby 21A-1 and Quinn 13-1; increased working interest payout for the La Posada wells; and LOE for the new Crosby 12-1 well net of a severance tax refund. The same factors as well as increased LOE attributable to our Addison properties caused a 53.2% increase in LOE from $6,371,172 in LOE for the nine months ended September 30, 2013 to $9,761,203 for the same period in 2014. LOE per barrel of oil equivalent decreased for the same period from $21.02 to $15.70, a 25.3% reduction primarily due to significantly increased production volumes.

Re-engineering and Workovers

Re-engineering and workover expenses include the costs to restore or enhance production in current producing zones as well as costs of significant non-recurring operations.

Workover expenses for the three months ended September 30, 2014 totaled $778,628 compared to $245,527 for the same period in 2013. Workover expenses for the nine months ended September 30, 2014 totaled $1,330,539, while such expenses for the same period in 2013 totaled $1,513,766.

General and Administrative Expenses

Our general and administrative ("G&A") expenses are summarized as follows:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
General and administrative				
Stock-based compensation	$521,978	$27,105	$613,917	$553,764
Capitalized	-	(9,144)	(15,099)	(126,390)
Net stock-based compensation	521,978	17,961	598,818	427,374
Other	3,033,711	1,881,676	9,335,235	5,849,574
Capitalized	(636,931)	(656,773)	(1,999,334)	(2,035,135)
Net Other	2,396,780	1,224,903	7,335,901	3,814,439
Net general and administrative	$2,918,758	$1,242,864	$7,934,719	$4,241,813

G&A expenses primarily consist of overhead expenses, employee remuneration and professional and consulting fees. The Company capitalizes certain G&A expenditures when they satisfy the criteria for capitalization under GAAP as relating to oil and gas exploration activities following the full cost method of accounting.

The net change in G&A expenses for the three months ended September 30, 2014 compared to the same period in 2013 was $1,675,894. Excluding stock-based compensation for 2014 and 2013 of $521,978 and $17,961, respectively, and $856,840 in professional costs associated with the merger completed in September 2014, G&A expenses for 2014 increased by $315,037, or 25.7%, over the same period in 2013. This increase was primarily the result of five (net) employee additions in 2014. For the nine month period ended September 30, 2014, G&A cost was $3,692,906 over the amount for the same period in 2013. Excluding stock-based compensation for 2014 and 2013 of $598,818 and $427,374, respectively, $1,287,332 in costs associated with exploring options to obtain a public listing, and $1,442,115 in professional costs associated with the merger, G&A expenses for 2014 increased by $792,015, or 20.8%, over the same period in 2013. This increase was primarily the result of several employee additions during the period.

Depreciation, Depletion and Amortization

Our depreciation, depletion and amortization ("DD&A") is summarized as follows:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
DD&A	$3,865,675	$3,203,017	$15,604,283	$7,315,103

The net quantities of oil, natural gas and natural gas liquids produced and sold by us increased by 19.5% in the three months ended September 30, 2014 compared to the same period in 2013, and 105.2% in the nine months ended September 30, 2014 compared to the same period in 2013. This increase in production was the primary factor for the increase in DD&A over the respective periods. Refer to "Sales and Other Operating Revenues" above for the oil and gas production discussion.

30

NON-GAAP FINANCIAL MEASURES

Adjusted EBITDA

The following table reconciles reporting net income to EBITDA and Adjusted EBITDA for the periods indicated:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net Income	$(11,152,037)	$15,814,648	$(18,997,712)	$(7,067,374)
Add: Depreciation, depletion & amortization of property and equipment	3,865,675	3,203,017	15,604,283	7,315,103
Add: Interest expense, net of interest income and amounts capitalized	112,078	62,009	316,850	482,564
Deduct: Income tax benefit	(576,632)	(2,040,000)	(1,710,632)	(1,998,800)
EBITDA	(7,750,916)	17,039,674	(4,787,211)	(1,268,507)
Add: Costs to obtain a public listing	844,482	-	2,729,447	-
Add (deduct): Increase (decrease) in value of preferred stock derivative liability	11,172,928	(15,382,964)	15,676,842	7,581,234
Add: Accretion of asset retirement obligation	150,628	187,025	438,717	464,306
Add: Bank mandated commodity derivative novation cost	-	-	-	175,000
Deduct: Amortization of benefit from commodity derivatives sold	(23,438)	(18,150)	(70,313)	(54,450)
Add (deduct): Net commodity derivatives mark-to-market loss (gain)	(2,607,959)	823,361	(921,026)	(439,478)
Adjusted EBITDA	$1,785,725	$2,648,946	$13,066,456	$6,458,105

"EBITDA" represents earnings before interest, taxes, depreciation, depletion and amortization, and is a non-GAAP financial measure. Because the Company makes other adjustments to its EBITDA formula by considering the change in the preferred stock derivative liability, accretion of asset retirement obligations, costs to obtain a public listing, and changes in commodity derivative values, management refers to this metric as Adjusted EBITDA and it is provided as an additional metric that is used by the Company's board of directors and management to measure operating performance and trends. Adjusted EBITDA for the three months ended September 30, 2014 decreased from the same period in 2013 by $863,221 (33%) and for the nine month period ended September 30, 2014, Adjusted EBITDA increased from the same period in 2013 by $6,608,351 (102%).

Adjusted EBITDA is presented based on management's belief that it will enable a user of the financial information to understand the impact of these items on reported results. Additionally, this presentation provides a helpful comparison to similarly adjusted measurements of prior periods. Adjusted EBITDA is not a measure of financial performance under GAAP and should not be considered as an alternative to net income, earnings per share and cash flow from operations, as defined by GAAP. Adjusted EBITDA may not be comparable to similarly named non-GAAP financial measures that other companies may use and may not be useful in comparing the performance of those companies to the Company's performance.

Interest Expense

Our interest expense for the three and nine month periods ended September 30, 2014 and 2013 is summarized as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Interest expense	$380,905	$313,479	$1,089,588	$1,277,002
Interest capitalized	(266,500)	(249,403)	(767,908)	(788,214)
Net	$114,405	$64,076	$321,680	$488,788
Bank debt	$24,965,000	$24,615,000	$24,965,000	$24,615,000

The three months ended September 30, 2014 had 49 days when the prime-based debt level increased enough to put it in a higher interest bracket of 5.25% instead of 5%, whereas the same period in 2013 had no days over 5% prime-based interest. Also, the second half of the three months ended September 30, 2014 had fewer LIBOR-based contracts, which are locked in for specified contract periods, in anticipation of the funds from our Series A Preferred Stock offering completed in October 2014.

The nine months ended September 30, 2013 included write-offs of debt costs due to the exit of two members of the loan syndicate. In February 2013, $123,924 of unamortized costs for Amegy Bank were expensed, and in May 2014, $189,727 of unamortized costs for Union Bank were expensed, both due to their exits from the syndicate. The nine months ended September 30, 2013 also included a one-time $32,383 charge from the State of Louisiana for interest from a Mineral Board Audit.

Income Tax Expense

The Company recorded an income tax benefit of $576,632 on a pre-tax net loss of $11,728,669 resulting in an effective tax rate of 5% for the three months ended September 30, 2014. The tax benefit is net of income tax expense of $123,368 related to certain non-cash compensation items. The pre-tax net loss includes a nondeductible expense of $11,172,928 for the change in fair value of the Series A and Series B Preferred Stock derivative liabilities. For the three months ended September 30, 2013, the Company recorded an income tax benefit of $2,040,000 on pre-tax income of $13,774,648, resulting in a negative effective tax rate of 15%. Income of $15,382,964 from the change in fair value of the Series A and Series B Preferred Stock derivative liabilities included in the pre-tax net income for the three months ended September 30, 2013 is not recognized for tax purposes.

The Company recorded an income tax benefit of $1,710,632 on a pre-tax net loss of $20,708,344 resulting in an effective tax rate of 8% for the nine months ended September 30, 2014. The tax benefit is net of income tax expense of $123,368 related to certain non-cash compensation items. The pre-tax net loss includes a nondeductible expense of $15,676,842 for the change in fair value of the Series A and Series B Preferred Stock derivative liabilities. For the nine months ended September 30, 2013, the Company recorded an income tax benefit of $1,998,000 on a pre-tax net loss of $9,066,174, resulting in an effective tax rate of 22%. A nondeductible expense of $7,581,234 from the change in fair value of the Series A and Series B Preferred Stock derivative liabilities is included in the pre-tax net loss for the nine months ended September 30, 2013.

Additionally, differences between the U.S. federal statutory rate of 35% and our effective tax rates are due to the tax effects of the excess of book carrying value over the tax basis in the full cost pool and the net operating loss carryforwards for each period.

Liquidity and Capital Resources

Cash Flows

Net increase in cash is summarized as follows:

	Nine Months Ended September 30,	
	2014	2013
Cash flows provided by operating activities	$22,693,909	$15,004,178
Cash flows used for investing activities	(10,805,820)	(21,617,381)
Cash flows provided by (used for) financing activities	(6,520,338)	6,148,258
Net increase (decrease) in cash	$5,367,751	$(464,945)

Cash Flows From Operating Activities

Cash flows from operations for the nine month period ended September 30, 2014 increased 51.3% over the same period of 2013 primarily due to increased production in the La Posada field and new production at the Crosby 12-1. These increases were somewhat mitigated by higher lease operating expenses associated with increasing production at La Posada, new production at Crosby 12-1 and the acquisition of the Addison properties in the Austin Chalk (acquired April 5, 2013).

Cash Flows From Investing Activities

	Nine Months Ended September 30, 2014	2013
Acquisition of acreage and new properties	$3,987,163	$10,831,259
Drilling and completion	14,481,398	9,696,045
Recompletions, capital workovers and plugging and abandoning (“P&A”)	(630,021)	1,727,716
Total oil and natural gas investing activities	17,838,540	22,255,020
Corporate office property and equipment purchases	62,724	58,634
Total cash used for capitalized expenditures on property and equipment	17,901,264	22,313,654
Proceeds from sale of property	(307,600)	(698,766)
Cash received in merger	(4,550,082)	-
Short-term investments retired	(2,142,128)	-
(Decrease) increase in noncurrent receivable from affiliate	(95,634)	2,493
Cash flows used for investing activities	$10,805,820	$21,617,381

During the nine months ended September 30, 2014, the Greater Masters Creek Field accounted for $14,886,638 of our total oil and natural gas investing activities. Of that, $1,837,333 was spent primarily on lease extensions and geological and geophysical activities. At the Livingston prospect, $1,400,028 was incurred to drill and complete the Nettles 39-1, of which $269,260 was spent on leasing. The remaining $13,049,305 represents drilling costs. A net credit of $669,670 for insurance recovery on the Grief Bros. No. 1 created a credit balance for recompletions, capital workovers and P&A for the period.

For the nine months ended September 30, 2013, lease related costs of $8,875,645 were incurred on the Austin Chalk Project, a part of the Greater Masters Creek Field. Other significant lease related costs for the first nine months of 2013 were $675,462 for Livingston and $781,217 for Amazon, and $625,325 in other leases. The Austin Chalk Project accounted for $5,434,289 in drilling, completion and workover costs, primarily the Crosby 12-1, with costs totaling $4,897,704. Costs incurred in the Bakken to drill and complete the Bunning 35-26 No. 1H and build the Jerry and Monson salt water disposal (“SWD”) facilities were $822,174. At La Posada, $1,160,375 was incurred to drill and complete the Broussard No. 1 side track and upgrade the production facilities. Other drilling costs incurred were $1,208,757 for the SLLO No. 1 at Amazon and $1,420,784 for the Starns 38-1 and the Weyerhaeuser 57-1 SWD at Livingston. $941,708 was spent to plug the Grief Bros No. 1 prior to the 2014 insurance recovery.

Cash Flows From Financing Activities

Our cash flows, both in the short-term and the long-term, are impacted by highly volatile oil and natural gas prices. Although we mitigate this risk by hedging a significant portion of future crude oil and natural gas production out two years (three to five years historically), a significant deterioration in commodity prices negatively impacts revenues, earnings, and cash flows, capital spending, and potentially our liquidity. Sales volumes and costs also impact cash flows; however, these historically have not been as volatile or as impactful as commodity prices in the short-term.

We expect to finance future acquisition, development and exploration activities through available working capital, cash flows from operating activities, advances from our credit facility, sale of non-strategic assets, and the possible issuance of additional equity/debt securities. In addition, we may slow or accelerate our development of existing reserves to more closely match our projected cash flows.

At September 30, 2014, we had a $40.0 million conforming borrowing base, with a $4.5 million additional non-conforming borrowing base, providing a total borrowing base of $44.5 million, with available borrowing capacity of $19,535,000 in accordance with our credit facility. The $4.5 million non-conforming available borrowing base expired October 15, 2014. The borrowing base is reviewed and redetermined in March and October of each year and was increased to the current level on April 22, 2014.

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013
Credit Facility:		
Balances outstanding, beginning of year	$31,215,000	$17,875,000
Activity	(6,250,000)	13,340,000
Balances outstanding, end of period	$24,965,000	$31,215,000

Other than the credit facility, we had debt of $565,166 and $178,027 at September 30, 2014 and December 31, 2013, respectively, from an installment loan financing oil and gas property insurance premiums. The Company had a cash balance of $9.6 million and short-term investments of $1.2 million at September 30, 2014.

Hedging Activities

Current Commodity Derivative Contracts

The Company seeks to reduce its sensitivity to oil and gas price volatility and secure favorable debt financing terms by entering into commodity derivative transactions which may include fixed price swaps, price collars, puts, calls and other derivatives. The Company believes its hedging strategy should result in greater predictability of internally generated funds, which in turn can be dedicated to capital development projects and corporate obligations.

Fair Market Value of Commodity Derivatives

	September 30, 2014		December 31, 2013	
	Oil	Gas	Oil	Gas
Assets				
Current	$325,028	$58,575	$-	$-
Noncurrent	548,573	-	818,637	-
Liabilities				
Current	-	-	(423,217)	(253,915)
Noncurrent	-	(20,849)	-	(218,649)

Assets and liabilities are netted within each commodity on the Consolidated Balance Sheets as all contracts are with the same counterparty. For the balances without netting, refer to Item 1. Unaudited Condensed Notes to the Consolidated Financial Statements, Note C – Commodity Derivative Instruments.

The fair market value of our commodity derivative contracts in place at September 30, 2014 and December 31, 2013 were net assets of $911,327 and net liabilities of $77,144, respectively.

We expect to reclassify losses on commodity derivatives of $26,792 net after taxes into earnings from accumulated other comprehensive income during the twelve months ending September 30, 2015; however, actual cash settlement gains and losses recognized may differ materially.

Please see Item 1. Unaudited Condensed Notes to the Consolidated Financial Statements, Note C – Commodity Derivative Instruments, for additional information on our commodity derivatives.

Hedging commodity prices for a portion of our production is a fundamental part of our corporate financial management. We do not engage in speculative commodity trading activities and do not hedge all available or anticipated quantities of our production. In implementing our hedging strategy we seek to:

effectively manage cash flow to minimize price volatility and generate internal funds available for operations, capital development projects and additional acquisitions; and

ensure our ability to support our exploration activities as well as administrative and debt service obligations.

Estimating the fair value of derivative instruments requires complex calculations, including the use of a discounted cash flow technique, estimates of risk and volatility, and subjective judgment in selecting an appropriate discount rate. In addition, the calculations use future market commodity prices which, although posted for trading purposes, are merely the market consensus of forecasted price trends. The results of the fair value calculation cannot be expected to represent exactly the fair value of our commodity derivatives. We currently obtain fair value positions from our counterparties and compare that value to the calculated value provided by our outside commodity derivative consultant. We believe that the practice of comparing the consultant's value to that of our counterparties, who are more specialized and knowledgeable in preparing these complex calculations, reduces our risk of error and approximates the fair value of the contracts, as the fair value obtained from our counterparties would be the cost to us to terminate a contract at that point in time.

Commitments and Contingencies

We had the following contractual obligations and commitments as of September 30, 2014:

	Debt (1)	Asset for Commodity Derivatives (2)	Operating Leases	Asset Retirement Obligations
2014	$-	$111,235	$135,181	$-
2015	565,166	347,656	544,718	1,188,711
2016	-	452,436	553,053	992,589
2017	24,965,000	-	538,291	311,865
2018	-	-	2,264	727,665
Thereafter	-	-	-	9,301,821
Totals	$25,530,166	$911,327	$1,773,507	$12,522,651

(1) This table does not include future commitment fees, interest expense or other fees because the credit agreement is a floating rate instrument, and we cannot determine with accuracy the timing of future loans, advances, repayments or future interest rates to be charged.

(2) Represents the estimated future payments under our oil and natural gas derivative contracts based on the future market prices as of September 30, 2014. These amounts will change as oil and natural gas commodity prices change.

Off Balance Sheet Arrangements

We do not have any balance sheet arrangements, special purpose entities, financing partnerships or guarantees (other than our guarantee of our wholly owned subsidiary's credit facility).

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide the information under this Item.

Item 4. Controls and Procedures.

Evaluation of disclosure controls and procedures. Our Chief Executive Officer and our Chief Financial Officer have concluded, based on their evaluation as of the end of the period covered by this Form 10-Q, that our disclosure controls and procedures, as defined under Rules 13a-15(e) and 15d-15(e) of the Exchange Act, are effective to ensure that information we are required to disclose in the reports we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that our disclosure controls and procedures are effective to ensure that information we are required to disclose in such reports is accumulated and communicated to management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in internal control over financial reporting. There have been no changes in our internal control over financial reporting that occurred during the three month period ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

A description of our legal proceedings is included in Item 1. Unaudited Condensed Notes to the Consolidated Financial Statements, Note I – Contingencies, and is incorporated herein by reference.

From time to time, we may be a plaintiff or defendant in a pending or threatened legal proceeding arising in the normal course of our business. While the outcome and impact of currently pending legal proceedings cannot be determined, our management and legal counsel believe that the resolution of these proceedings through settlement or adverse judgment will not have a material effect on our consolidated operating results, financial position or cash flows.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A – Risk Factors" in our Annual Report for the year ended December 31, 2013 on Form 10-K, as amended, which could materially affect our business, financial condition or future results. The risks described in our 2013 Annual Report on Form 10-K, as amended, may not be the only risks facing our Company. There are no updates to our risk factors as disclosed in our Annual Report on Form 10-K and 10-K/A for the year ended December 31, 2013, except as noted below. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial may materially adversely affect our business, financial condition and/or operating results.

Oil and natural gas prices are volatile, and low prices could have a material adverse impact on our business.

Our revenues, profitability and future growth and the carrying value of our properties depend substantially on prevailing oil and natural gas prices. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow and raise additional capital. The amount we will be able to borrow under our credit agreement will be subject to periodic redetermination based in part on current oil and natural gas prices and on changing expectations of future prices. Lower prices may also reduce the amount of oil and natural gas that we can economically produce and have an adverse effect on the value of our properties.

Historically, the markets for oil and natural gas have been volatile, and they are likely to continue to be volatile in the future. Among the factors that can cause volatility are:

- the domestic and foreign supply of oil and natural gas;
- the ability of members of the Organization of Petroleum Exporting Countries and other producing countries to agree upon and maintain oil prices and production levels;
- social unrest and political instability, particularly in major oil and natural gas producing regions outside the United States, such as northern Africa and the Middle East, and armed conflict or terrorist attacks, whether or not in oil or natural gas producing regions;
- the level of consumer product demand;
- the growth of consumer product demand in emerging markets, such as China;
- labor unrest in oil and natural gas producing regions;

weather conditions, including hurricanes and other natural occurrences that affect the supply and/or demand of oil and natural gas;

the price and availability of alternative fuels;

the price of foreign imports;

worldwide economic conditions; and

the availability of liquid natural gas imports.

These external factors and the volatile nature of the energy markets make it difficult to estimate future prices of oil and natural gas.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations.

We may not be able to drill wells on a substantial portion of our acreage.

We may not be able to drill on a substantial portion of our acreage for various reasons. We may not generate or be able to raise sufficient capital to do so. Future deterioration in commodities prices may also make drilling some acreage uneconomic. Our actual drilling activities and future drilling budget will depend on drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, lease expirations, gathering system and pipeline transportation constraints, regulatory approvals and other factors. In addition, any drilling we are able to conduct may not be successful or add additional proved reserves to our overall proved reserves, which could have a material adverse effect on our future business, financial condition and results of operations.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by transportation capacity constraints and interruptions.

If the amount of natural gas, condensate or oil being produced by us and others exceeds the capacity of the various transportation pipelines and gathering systems available in our operating areas, it will be necessary for new transportation pipelines and gathering systems to be built. Or, in the case of oil and condensate, it will be necessary for us to rely more heavily on trucks to transport our production, which is more expensive and less efficient than transportation via pipeline. Currently, we anticipate that additional pipeline capacity will be required in the Bakken / Three Forks formations area to transport oil and condensate production, which increased substantially during 2012 and 2013 and is expected to continue to increase. The construction of new pipelines and gathering systems is capital intensive and construction may be postponed, interrupted or cancelled in response to changing economic conditions and the availability and cost of capital. In addition, capital constraints could limit our ability to build gathering systems to transport our production to transportation pipelines. In such event, costs to transport our production may increase materially or we might have to shut in our wells awaiting a pipeline connection or capacity and/or sell our production at much lower prices than market or than we currently project, which would adversely affect our results of operations.

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of weather conditions, accidents, loss of pipeline or gathering system access, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Unless we replace our reserves, our reserves and production will decline, which would adversely affect our financial condition, results of operations and cash flows.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Decline rates are typically greatest early in the productive life of a well. Estimates of the decline rate of an oil or natural gas well are inherently imprecise, and are less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Our production levels and the reserves that we currently expect to recover from our wells will change if production from our existing wells decline in a different manner than we have estimated and can change under other circumstances. Thus, our future oil and natural gas reserves and production and, therefore, our cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting our current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace current and future production at acceptable costs. If we are unable to replace current and future production, cash flows and the value of reserves may decrease, adversely affecting our business, financial condition and results of operations.

Estimates of proved oil and natural gas reserves involve assumptions and any material inaccuracies in these assumptions will materially affect the quantities and the value of our reserves.

This report contains estimates of our proved oil and natural gas reserves. These estimates are based upon various assumptions, including assumptions required by the SEC relating to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil and natural gas reserves is complex. This process requires significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Therefore, these estimates are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from those estimated. Any significant variance could materially affect the estimated quantities and the value of our reserves. Our properties may also be susceptible to hydrocarbon drainage from production by other operators on adjacent properties. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

At December 31, 2013, approximately 80.0% of our estimated reserves (as consolidated on a pro forma basis with our two subsidiaries) were classified as proved undeveloped. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data assume that we will make significant capital expenditures to develop our reserves. The estimates of these oil and natural gas reserves and the costs associated with development of these reserves have been prepared in accordance with SEC regulations; however, actual capital expenditures will likely vary from estimated capital expenditures, development may not occur as scheduled and actual results may not be as estimated.

We depend substantially on the continued presence of key personnel for critical management decisions and industry contacts.

Our success depends upon the continued contributions of our executive officers and key employees, particularly with respect to providing the critical management decisions and contacts necessary to manage and maintain growth within a highly competitive industry. Competition for qualified personnel can be intense, particularly in the oil and natural gas industry, and there are a limited number of people with the requisite knowledge and experience. Under these conditions, we could be unable to attract and retain these personnel. The loss of the services of any of our executive officers or other key employees for any reason could have a material adverse effect on our business, operating results, financial condition and cash flows.

Our business is highly competitive.

The oil and natural gas industry is highly competitive in many respects, including identification of attractive oil and natural gas properties for acquisition, drilling and development, securing financing for such activities and obtaining the necessary equipment and personnel to conduct such operations and activities. In seeking suitable opportunities, we compete with a number of other companies, including large oil and natural gas companies and other independent operators with greater financial resources, larger numbers of personnel and facilities, and, in some cases, with more expertise than we have.

Our oil and natural gas activities are subject to various risks which are beyond our control.

Our operations are subject to many risks and hazards incident to exploring and drilling for, producing, transporting, marketing and selling oil and natural gas. Although we may take precautionary measures, many of these risks and hazards are beyond our control and unavoidable under the circumstances. Many of these risks or hazards could materially and adversely affect our revenues and expenses, the ability of certain of our wells to produce oil and natural gas in commercial quantities, the rate of production and the economics of the development of, and our investment in the prospects in which we have or will acquire an interest. Any of these risks and hazards could materially and adversely affect our financial condition, results of operations and cash flows. Such risks and hazards include:

human error, accidents, labor force and other factors beyond our control that may cause personal injuries or death to persons and destruction or damage to equipment and facilities;

blowouts, fires, hurricanes, pollution and equipment failures that may result in damage to or destruction of wells, producing formations, production facilities and equipment and increased drilling and production costs;

unavailability of materials and equipment;

engineering and construction delays;

unanticipated transportation costs and delays;

unfavorable weather conditions;

hazards resulting from unusual or unexpected geological or environmental conditions;

environmental regulations and requirements;

accidental leakage of toxic or hazardous materials, such as petroleum liquids or drilling fluids, into the environment;

hazards resulting from the presence of hydrogen sulfide or other contaminants in natural gas we produce;

changes in laws and regulations, including laws and regulations applicable to oil and natural gas activities or markets for the oil and natural gas produced;

fluctuations in supply and demand for oil and natural gas causing variations of the prices we receive for our oil and natural gas production; and

the availability of alternative fuels and the price at which they become available.

As a result of these risks, expenditures, quantities and rates of production, revenues and operating costs may be materially adversely affected and may differ materially from those we anticipate.

Our exploration and development drilling efforts and the operation of our wells may not be profitable or achieve our targeted returns.

We require significant amounts of undeveloped leasehold acreage to further our development efforts. Exploration, development, drilling and production activities are subject to many risks, including the risk that commercially productive reservoirs will not be discovered. We invest in property, including undeveloped leasehold acreage, which we believe will result in projects that will add value over time. Our leasehold acreage may not be profitably developed, new wells drilled by us may not be productive and we may not recover all or any portion of our investment in such leasehold acreage or wells. Drilling for oil and natural gas may involve unprofitable efforts, not only from dry wells but also from wells that are productive but do not produce sufficient revenues to return a profit after deducting operating and other costs. In addition, wells that are profitable may not achieve our targeted rate of return. Our ability to achieve our target results is dependent upon the current and future market prices for oil and natural gas, costs associated with producing oil and natural gas and our ability to add reserves at an acceptable cost.

In addition, we may not be successful in controlling our drilling and production costs to improve our overall return. The cost of drilling, completing and operating a well is often uncertain and cost factors can adversely affect the economics of a project. We cannot predict the cost of drilling and completing a well, and we may be forced to limit, delay or cancel drilling operations as a result of a variety of factors, including:

unexpected drilling conditions;

pressure or irregularities in formations;

equipment failures or accidents and shortages or delays in the availability of drilling and completion equipment and services;

adverse weather conditions, including hurricanes; and

compliance with governmental requirements.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Companies that explore for and develop, produce, sell and transport oil and natural gas in the United States are subject to extensive federal, state and local laws and regulations, including complex tax and environmental, health and safety laws and their corresponding regulations, and are required to obtain various permits and approvals from federal, state and local agencies. If these permits are not issued or unfavorable restrictions or conditions are imposed on our drilling activities, we may not be able to conduct operations as planned. We may be required to make large expenditures to comply with governmental regulations. Matters subject to regulation include:

water discharge and disposal permits for drilling operations;

drilling bonds;

drilling permits;

- reports concerning operations;
- air quality, noise levels and related permits;
- spacing of wells;
- rights-of-way and easements;
- unitization and pooling of properties;
- pipeline construction;
- gathering, transportation and marketing of oil and natural gas;
- taxation; and
- waste transport and disposal permits and requirements.

Failure to comply with these laws may result in the suspension or termination of operations and subject us to liabilities under administrative, civil and criminal penalties. Compliance costs can be significant. Moreover, these laws or the enforcement thereof could change in ways that substantially increase our costs of doing business. Any such liabilities, penalties, suspensions, terminations or regulatory changes could materially and adversely affect our business, financial condition and results of operations. Under these laws and other environmental health and safety laws and regulations, we could be held liable for personal injuries, property damage (including site clean-up and restoration costs) and other damages including the assessment of natural resource damages. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. Some laws and regulations may impose strict as well as joint and several liability for environmental contamination, which could subject us to liability for the conduct of others or for our own actions that were in compliance with all applicable laws at the time such actions were taken. Environmental and other governmental laws and regulations also increase the costs to plan, design, drill, install, operate and abandon oil and natural gas wells. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects. Part of the regulatory environment in which we operate includes, in some cases, federal requirements for performing or preparing environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to regulation by oil and natural gas-producing states relating to conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. Delays in obtaining regulatory approvals or necessary permits, the failure to obtain a permit or the receipt of a permit with excessive conditions or costs could have a material adverse effect on our ability to explore on, develop or produce our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

From time to time, legislation has been proposed in Congress to amend the federal Safe Drinking Water Act to require federal permitting of hydraulic fracturing and the disclosure of chemicals used in the hydraulic fracturing process. Federal, state, tribal and local governments have been adopting or considering restrictions on or prohibitions of fracturing in areas where we have operated and non-operated working interests and the operator of such properties could be subject to additional levels of regulation, operational delays or increased operating costs and could have regulatory burdens imposed upon it that could make it more difficult to perform hydraulic fracturing and increase the costs of compliance and doing business.

At the Federal level, for example, the EPA is conducting a wide-ranging study on the effects of hydraulic fracturing on drinking water resources. In December 2012, the EPA issued a progress report describing its ongoing study, and announcing its expectation that a final draft report will be released for public comment and peer review in 2014. Other governmental reviews have also been recently conducted or are under way that focus on environmental aspects of hydraulic fracturing, including for example, a Federal Bureau of Land Management rulemaking for hydraulic fracturing practices on federal and Indian lands that has resulted in a May 2013 proposal that would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that the wells used in fracturing operations meet proper construction standards and development of plans for managing flowback water from such activities. These activities could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase the costs of compliance and doing business with regard to our operated and non-operated properties.

Certain states likewise have adopted, and other states are considering the adoption of regulations that impose new or more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit drilling in general or hydraulic fracturing in particular. Such efforts have extended to bans on hydraulic fracturing.

As a working interest owner, we use a significant amount of water with respect to hydraulic fracturing operations. The inability to locate sufficient amounts of water, or dispose of or recycle water used in exploration and production operations, could adversely impact our operations. Moreover, new environmental initiatives and regulations could include restrictions on our ability to participate in certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of oil and natural gas. Compliance with environmental regulations and regulatory permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase the operating costs of our properties and cause delays, interruptions or termination of operations, all of which could have an adverse effect on our results of operations and financial condition.

Hydraulic fracturing involves the injection of water, sand and various chemicals under pressure into geologic formations to fracture the surrounding rock and stimulate production. This process may give rise to operational issues such as an underground migration of water and chemicals to unintended areas, wellbore integrity, possible surface spillage and contamination caused by mishandling of fracturing fluids, including chemical additives. Properly administering the hydraulic fracturing process entails operational costs and a failure to properly administer the process could cause significant remedial and financial costs.

Regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and natural gas.

Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, governments have been adopting domestic and international climate change regulations that require reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change, and the Kyoto Protocol address greenhouse gas emissions, and several countries, including those comprising the European Union, have established greenhouse gas regulatory systems.

In the United States, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories, emission targets, greenhouse gas cap and trade programs or incentives for renewable energy generation, while others have considered adopting such greenhouse gas programs.

At the federal level, the Obama Administration is attempting to address climate change through a variety of administrative actions. The EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and required reporting by regulated facilities by March 2011 and annually thereafter. In November 2010, the EPA extended the reporting obligation to oil and natural gas facilities. On July 19, 2011, the EPA amended the oil and natural gas facility greenhouse gas reporting rule to require reporting beginning in September 2012. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding certain greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding served as the first step to issuing regulations that require permits for and reductions in greenhouse gas emissions for certain facilities. In March 2014, moreover, the President released a Strategy to Reduce Methane Emissions that includes consideration of both voluntary programs and targeted regulations for the oil and gas sector. Towards that end, the EPA has released five draft white papers on methane and volatile organic compound emissions and mitigation measures for natural gas compressors, hydraulically fractured oil wells, pneumatic devices, well liquids unloading facilities and natural gas production and transmission facilities. The EPA is seeking responses to the white papers and intends to use this process to determine how best to pursue additional emission reductions from the oil and gas sector. Also as part of the President's strategy, the Federal Bureau of Land Management is expected to propose standards for reducing venting and flaring on public lands.

In the courts, several decisions have been issued that may increase the risk of claims being filed by governments and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur additional operating costs, such as costs to purchase and operate emissions controls or other compliance costs, and reduce demand for our products.

The ongoing implementation of federal legislation enacted in 2010 could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with its business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production and, periodically, interest expense. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation. The CFTC, in coordination with the SEC and various U.S. federal banking regulators, has issued regulations to implement the so-called “Volcker Rule” under which banking entities are generally prohibited from proprietary trading of derivatives. Although conditional exemptions from this general prohibition are available, the Volcker Rule may limit the trading activities of banking entities that have been counterparties to our derivatives trades in the past. Also, a provision of the Dodd-Frank Act known as the “swaps push-out rule” may require some of the banking counterparties to our commodity derivative contracts to “push out” some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The CFTC also has finalized other regulations implementing the Dodd-Frank Act’s provisions regarding trade reporting, margin and position limits; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the Dodd-Frank Act and the CFTC regulations may require compliance with margin requirements and with certain clearing and trade-execution requirements in connection with certain of our derivative activities. Also, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. It is possible that the CFTC, in conjunction with the U.S. federal banking regulators, may mandate that financial counterparties entering into swap transactions with end-users must do so with credit support agreements in place, which could result in negotiated credit thresholds above which we would be required to post collateral.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we may encounter, reduce our ability to monetize or restructure our existing commodity derivative contracts, and potentially increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a consequence, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

We cannot be certain that the insurance coverage we maintain will be adequate to cover all losses that may be sustained in connection with our oil and natural gas activities.

We maintain general and excess liability policies, which we consider to be reasonable and consistent with industry standards. These policies generally cover:

personal injury;

bodily injury;

third party property damage;

medical expenses;

legal defense costs;

pollution in some cases;

well blowouts in some cases; and

workers compensation.

As is common in the oil and natural gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations and cash flows.

Title to the properties in which we have an interest may be impaired by title defects.

We generally obtain title opinions on significant properties that we drill or acquire. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. Generally, under the terms of the operating agreements affecting our properties, any monetary loss is to be borne by all parties to any such agreement in proportion to their interests in such property. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

The unavailability or high cost of drilling rigs, pressure pumping equipment and crews, other equipment, supplies, water, personnel and oil field services could adversely affect our ability to execute our exploration and development plans on a timely basis and within our budget.

The oil and gas industry is cyclical and, from time to time, there are shortages of drilling rigs, equipment, supplies, water or qualified personnel. During these periods, the costs and delivery times of rigs, equipment and supplies are substantially greater. In addition, the demand for, and wage rates of, qualified drilling rig crews rise as the number of active rigs in service increases. Increasing levels of exploration and production may increase the demand for oilfield services and equipment, and the costs of these services and equipment may increase, while the quality of these services and equipment may suffer. The unavailability or high cost of drilling rigs, pressure pumping equipment, supplies or qualified personnel can materially and adversely affect our operations and profitability. In order to secure drilling rigs and pressure pumping equipment, we have entered into certain contracts that extend over several months. If demand for drilling rigs and pressure pumping equipment subside during the period covered by these contracts, the price we are required to pay may be significantly more than the market rate for similar services.

We depend on the skill, ability and decisions of third-party operators of the oil and natural gas properties in which we have a non-operated working interest.

The success of the drilling, development and production of the oil and natural gas properties in which we have or expect to have a non-operating working interest is substantially dependent upon the decisions of our third-party operators and their diligence to comply with various laws, rules and regulations affecting such properties. The failure of any third-party operator to make decisions, perform its services, discharge its obligations, deal with regulatory agencies, and comply with laws, rules and regulations, including environmental laws and regulations in a proper manner with respect to properties in which we have an interest could result in material adverse consequences to our interest in such properties, including substantial penalties and compliance costs. Such adverse consequences could result in substantial liabilities to us or reduce the value of our properties, which could negatively affect our results of operations.

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into oil, natural gas, and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile oil, natural gas and natural gas liquids prices, these transactions may limit our potential gains and increase our potential losses if oil, natural gas and natural gas liquids prices were to rise substantially over the price established by the hedges. In addition, these transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or
- the counterparties to our hedging agreements fail to perform under the contracts.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None.

Item 3. Defaults Upon Senior Securities.

None.

Item 4. Mine Safety Disclosure.

Not Applicable.

Item 5. Other Information.

None.

Item 6. Exhibits.

EXHIBIT INDEX

FOR

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

Exhibit No.	Description	Incorporated by Reference Form	SEC File No.	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
10.1	Employment Agreement dated October 15, 2014 between Yuma Energy, Inc. and Paul D. McKinney.					X	
31.1	Certification of the Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X	
31.2	Certification of the Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.					X	
32.1	Certification of the Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X
32.2	Certification of the Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act.						X
101.INS*	XBRL Instance Document.						X
101.SCH*	XBRL Schema Document.						X
101.CAL*	XBRL Calculation Linkbase Document.						X
101.DEF*	XBRL Definition Linkbase Document.						X
101.LAB*	XBRL Label Linkbase Document.						X
101.PRE*							X

	XBRL Presentation Linkbase Document.

* XBRL (eXtensible Business Reporting Language) information is furnished and not filed or a part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, as amended, and otherwise is not subject to liability under these sections.

SIGNATURES

Pursuant to the requirements 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.

YUMA ENERGY, INC.

	By: /s/ Sam L. Banks
	Name: Sam L. Banks
Date: November 14, 2014	Title: President and Chief Executive Officer (Principal Executive Officer)

	By: /s/ Kirk F. Sprunger
Date: November 14, 2014	Name: Kirk F. Sprunger
	Title: Chief Financial Officer (Principal Financial Officer)