Midstates Petroleum Company, Inc.
Form 10-Q
November 14, 2013
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended September 30, 2013

OR

o 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: 001-35512

MIDSTATES PETROLEUM COMPANY, INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**45-3691816** (I.R.S. Employer Identification No.)
4400 Post Oak Parkway, Suite 1900 **Houston, Texas** (Address of principal executive offices)	**77027** (Zip Code)

(713) 595-9400

(Registrant s telephone number, including area code)

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 o

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 o

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

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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

The number of shares outstanding of our common stock at November 11, 2013 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	68,406,750

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.

QUARTERLY REPORT ON

FORM 10-Q

FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2013

TABLE OF CONTENTS

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

Bbl: One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe: Barrel of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

Boe/d: Barrels of oil equivalent per day.

Completion: The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Dry hole: A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production do not exceed production expenses and taxes.

Exploratory well: A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir.

Mcf: One thousand cubic feet of natural gas.

MMBoe: One million barrels of oil equivalent.

Net acres: The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

NYMEX: The New York Mercantile Exchange.

Proved reserves: Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Reasonable certainty: A high degree of confidence.

Recompletion: The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Reserves: Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations.

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

Spud or Spudding: The commencement of drilling operations of a new well.

Wellbore: The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

Working interest: The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on a cash, penalty, or carried basis.

Table of Contents

PART I - FINANCIAL INFORMATION

MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share amounts)

	September 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 24,953	$ 18,878
Accounts receivable:		
Oil and gas sales	88,216	35,618
Joint interest billing	28,985	10,815
Other	2,844	3,866
Commodity derivative contracts	3,783	5,695
Deferred income taxes	16,196	6,027
Other current assets	691	8,573
Total current assets	165,668	89,472
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting	2,914,422	1,836,664
Other property and equipment	10,029	5,038
Less accumulated depreciation, depletion, and amortization	(443,852)	(274,294)
Net property and equipment	2,480,599	1,567,408
OTHER ASSETS:		
Commodity derivative contracts	300	1,717
Other noncurrent assets	57,903	25,413
Total other assets	58,203	27,130
TOTAL	**$ 2,704,470**	**$ 1,684,010**
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 34,686	$ 29,196
Accrued liabilities	198,695	98,649
Commodity derivative contracts	28,463	7,582
Total current liabilities	261,844	135,427
LONG-TERM LIABILITIES:		
Asset retirement obligations	23,178	15,245
Commodity derivative contracts	6,730	3,943
Long-term debt	1,606,150	694,000
Deferred income taxes	149,991	156,737
Other long-term liabilities	1,862	1,189
Total long-term liabilities	1,787,911	871,114

COMMITMENTS AND CONTINGENCIES (Note 13)				
STOCKHOLDERS EQUITY				
Preferred stock, $0.01 par value, 49,675,000 shares authorized; no shares issued or outstanding				
Series A mandatorily convertible preferred stock, $0.01 par value, $351,520 and $325,000 liquidation value at September 30, 2013 and December 31, 2012, respectively; 8% cumulative dividends; 325,000 shares issued and outstanding		3		3
Common stock, $0.01 par value, 300,000,000 shares authorized; 68,686,256 shares issued and 68,579,198 outstanding at September 30, 2013 and 66,619,711 shares issued and outstanding at December 31, 2012		686		666
Treasury stock		(605)		
Additional paid-in-capital		869,939		863,891
Retained deficit		(215,308)		(187,091)
Total stockholders equity		654,715		677,469
TOTAL	**$**	**2,704,470**	**$**	**1,684,010**

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share amounts)

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
REVENUES:				
Oil sales	$ 119,049	$ 53,143	$ 268,903	$ 146,281
Natural gas liquid sales	18,939	4,134	39,656	14,307
Natural gas sales	18,775	2,257	42,034	8,086
Losses on commodity derivative contracts net	(45,296)	(33,726)	(42,999)	(10,249)
Other	38	124	941	331
Total revenues	111,505	25,932	308,535	158,756
EXPENSES:				
Lease operating and workover	21,784	6,569	53,230	18,957
Gathering and transportation	2,583		2,583	
Severance and other taxes	8,080	6,450	20,614	18,098
Asset retirement accretion	421	165	988	463
Depreciation, depletion, and amortization	74,789	30,692	169,595	86,601
General and administrative	13,911	7,948	40,209	18,966
Acquisition and transaction costs	194	2,675	11,686	2,675
Other	614		614	
Total expenses	122,376	54,499	299,519	145,760
OPERATING INCOME (LOSS)	(10,871)	(28,567)	9,016	12,996
OTHER INCOME (EXPENSE)				
Interest income	7	80	17	229
Interest expense net of amounts capitalized	(25,950)	(908)	(53,438)	(3,587)
Total other income (expense)	(25,943)	(828)	(53,421)	(3,358)
INCOME (LOSS) BEFORE TAXES	(36,814)	(29,395)	(44,405)	9,638
Income tax benefit (expense)	13,208	11,592	16,188	(157,326)
NET LOSS	$ (23,606)	$ (17,803)	$ (28,217)	$ (147,688)
Preferred stock dividend (Note 10)	(2,569)		(9,254)	
Participating securities - Series A Preferred Stock				
Participating securities - Non-vested Restricted Stock				
NET LOSS ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ (26,175)	$ (17,803)	$ (37,471)	$ (147,688)

Basic and diluted net loss per share attributable to common shareholders	$ (0.40)	$ (0.27)	$ (0.57)	$ (2.54)
Basic and diluted weighted average number of common shares outstanding	65,821	65,634	65,740	58,080

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY

(Unaudited)

(See Note 10 for Share History)

(In thousands)

	Series A Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in-Capital	Retained Deficit	Total Stockholders Equity
Balance as of December 31, 2012	$ 3	$ 666	$	$ 863,891	$ (187,091)	$ 677,469
Share-based compensation		20		6,048		6,068
Acquisition of treasury stock			(605)			(605)
Net loss					(28,217)	(28,217)
Balance as of September 30, 2013	$ 3	$ 686	$ (605)	$ 869,939	$ (215,308)	$ 654,715

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (28,217)	$ (147,688)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Unrealized losses (gains) on commodity derivative contracts, net	26,997	(5,591)
Asset retirement accretion	988	463
Depreciation, depletion, and amortization	169,595	86,601
Share - based compensation, net of amounts capitalized to oil and gas properties	4,921	1,568
Deferred income taxes	(16,188)	157,326
Amortization of deferred financing costs	4,156	583
Change in operating assets and liabilities:		
Accounts receivable oil and gas sales	(52,598)	1,193
Accounts receivable JIB and other	(13,544)	2,954
Other current and noncurrent assets	(2,622)	(3,547)
Accounts payable	(3,027)	(1,211)
Accrued liabilities	89,666	2,151
Other	(186)	(122)
Net cash provided by operating activities	$ 179,941	$ 94,680
CASH FLOWS FROM INVESTING ACTIVITIES:		
Investment in property and equipment	(437,521)	(284,875)
Investment in acquired property	(621,748)	
Net cash used in investing activities	$ (1,059,269)	$ (284,875)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from long - term borrowings	946,450	84,667
Repayment of long - term borrowings	(34,300)	(103,167)
Proceeds from issuance of mandatorily redeemable convertible preferred units		65,000
Repayment of mandatorily redeemable convertible preferred units		(65,000)
Proceeds from sale of common stock, net of initial public offering expenses of $6.4 million		213,587
Deferred financing costs	(26,142)	(7,562)
Acquisition of treasury stock	(605)	
Net cash provided by financing activities	$ 885,403	$ 187,525
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	6,075	(2,670)
Cash and cash equivalents, beginning of period	18,878	7,344

Cash and cash equivalents, end of period	$	24,953	$	4,674
SUPPLEMENTAL INFORMATION:				
Non - cash transactions investments in property and equipment accrued not paid	$	100,500	$	90,614
Cash paid for interest, net of capitalized interest of $24.6 million and $3.2 million, respectively		11,671		3,176

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

Table of Contents

MIDSTATES PETROLEUM COMPANY, INC.

Notes to Unaudited Condensed Consolidated Financial Statements

1. Organization and Business

Midstates Petroleum Company, Inc., through its wholly owned subsidiary Midstates Petroleum Company LLC, engages in the business of drilling for, and production of, oil, natural gas liquids and natural gas. Midstates Petroleum Company, Inc. was incorporated pursuant to the laws of the State of Delaware on October 25, 2011 to become a holding company for Midstates Petroleum Company LLC (Midstates Sub), which was previously a wholly owned subsidiary of Midstates Petroleum Holdings LLC (Holdings LLC). Pursuant to the terms of a corporate reorganization that was completed in connection with the closing of Midstates Petroleum Company, Inc. s initial public offering on April 25, 2012, all of the interests in Midstates Petroleum Holdings LLC were exchanged for newly issued common shares of Midstates Petroleum Company, Inc., and as a result, Midstates Petroleum Company LLC became a wholly owned subsidiary of Midstates Petroleum Company, Inc. and Midstates Petroleum Holdings LLC ceased to exist as a separate entity. The terms the Company, we, us, our, and similar terms when used i the present tense, prospectively or for historical periods since April 25, 2012, refer to Midstates Petroleum Company, Inc. and its subsidiary, and for historical periods prior to April 25, 2012, refer to Midstates Petroleum Holdings LLC and its subsidiary, unless the context indicates otherwise. The term Holdings LLC refers solely to Midstates Petroleum Holdings LLC prior to the corporate reorganization.

On October 1, 2012, the Company closed on the acquisition of all of Eagle Energy Production, LLC s producing properties as well as its developed and undeveloped acreage primarily in the Mississippian Lime liquids play in Oklahoma and Kansas for $325 million in cash and 325,000 shares of the Company s Series A Preferred Stock with an initial liquidation preference value of $1,000 per share (the Eagle Property Acquisition). The Company funded the cash portion of the Eagle Property Acquisition purchase price with a portion of the net proceeds from the private placement of $600 million in aggregate principal amount of 10.75% senior unsecured notes due 2020, which also closed on October 1, 2012.

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (the Anadarko Basin Acquisition). The Company funded the purchase price with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021, which also closed on May 31, 2013.

Subsequent to the closing of the Eagle Property Acquisition and the Anadarko Basin Acquisition, the Company has oil and gas operations and properties in Louisiana, Oklahoma, Texas and Kansas. At September 30, 2013, the Company operated oil and natural gas properties as one reportable segment engaged in the exploration, development and production of oil, natural gas liquids and natural gas. The Company s management evaluated performance based on one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

2. Summary of Significant Accounting Policies

Basis of Presentation

These interim financial statements are unaudited and have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (GAAP) for complete consolidated financial statements, and should be read in conjunction with the audited consolidated financial statements and notes thereto for the year ended December 31, 2012 included in the Company s Annual Report on Form 10-K as filed with the SEC on March 21, 2013.

All intercompany transactions have been eliminated in consolidation. In the opinion of the Company s management, the accompanying unaudited condensed consolidated financial statements include all adjustments, consisting of normal recurring adjustments, necessary to fairly present the financial position as of, and the results of operations for, all periods presented. In preparing the accompanying condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.

Recent Accounting Pronouncements

The Company reviewed recently issued accounting pronouncements that became effective during the nine months ended September 30, 2013, and determined that none would have a material impact on the Company s condensed consolidated financial statements with the exception of the adoption of ASU 2011-11, Disclosures About Offsetting Assets and Liabilities , which the Company adopted on January 1, 2013 and applies to the disclosures regarding commodity derivative contracts discussed in Note 4.

Correction of the 2012 Net Deferred Tax Liability

In the third quarter of 2013, the Company determined that its 2012 accounting for the tax impacts of the merger of certain entities that occurred in connection with the Company s initial public offering was in error. The Company identified that certain tax attributes acquired from the merged entities were not properly identified. Because the tax attributes were acquired as a result of a merger of entities under common control, the impacts of these tax attributes should have been recorded through equity at the time the Company became a taxable entity.

Table of Contents

To correct the 2012 tax error, the Company has restated the accompanying Condensed Consolidated Balance Sheet as of December 31, 2012. There was no impact to the Condensed Consolidated Statement of Operations for the year ended December 31, 2012, the three and nine months ended September 30, 2012, or the Condensed Consolidated Statement of Cash Flows for the nine months ended September 30, 2012. The impact of the correction is shown in the table below (in thousands):

	December 31, 2012	
Balance Sheet	**As Previously Reported**	**As Restated**
Deferred income taxes	$ 190,625	$ 156,737
Total long-term liabilities	905,002	871,114
Additional paid-in-capital	830,003	863,891
Total stockholders equity	643,581	677,469

3. Fair Value Measurements of Financial Instruments

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources; whereas, unobservable inputs reflect a company s own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further divided into the following fair value input hierarchy:

- **Level 1** Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date.

- **Level 2** Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are commodity derivative contracts with fair values based on inputs from actively quoted markets. The Company uses a discounted cash flow approach to estimate the fair values of its commodity derivative contracts, utilizing commodity futures price strips for the underlying commodities provided by a reputable third-party. The Company also factors the credit standing of its derivative contract counterparties into the valuation to account for the possible risk of nonperformance.

- **Level 3** Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability.

Assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis

Derivative Instruments

Commodity derivative contracts reflected in the condensed consolidated balance sheets are recorded at estimated fair value. At September 30, 2013 and December 31, 2012, all of the Company s commodity derivative contracts were with nine and five bank counterparties, respectively, and were classified as Level 2.

Derivative instruments listed below are presented gross and include collars and swaps that are carried at fair value. The Company records the net change in the fair value of these positions in Gains (losses) on commodity derivative contracts net in the Company s unaudited condensed consolidated statements of operations. See Note 4 for additional information on the Company s derivative instruments and balance sheet presentation.

Table of Contents

	Fair Value Measurements at September 30, 2013			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Commodity derivative oil swaps	$	$ 4,432	$	$ 4,432
Commodity derivative NGL swaps		1,345		1,345
Commodity derivative gas swaps		4,294		4,294
Commodity derivative oil collars		68		68
Commodity derivative gas collars		1,349		1,349
Commodity derivative differential swaps		1,254		1,254
Total assets	$	$ 12,742	$	$ 12,742
Liabilities:				
Commodity derivative oil swaps	$	$ 43,079	$	$ 43,079
Commodity derivative NGL swaps		54		54
Commodity derivative oil collars		496		496
Commodity derivative gas collars		21		21
Commodity derivative differential swaps		202		202
Total liabilities	$	$ 43,852	$	$ 43,852

	Fair Value Measurements at December 31, 2012			
	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
		(in thousands)		
Assets:				
Commodity derivative oil swaps	$	$ 16,133	$	$ 16,133
Commodity derivative NGL swaps		2,353		2,353
Commodity derivative oil collars		428		428
Commodity derivative gas collars		2,026		2,026
Commodity derivative differential swaps		2,661		2,661
Total assets	$	$ 23,601	$	$ 23,601
Liabilities:				
Commodity derivative oil swaps	$	$ 15,091	$	$ 15,091
Commodity derivative NGL swaps		458		458
Commodity derivative oil collars		287		287
Commodity derivative gas collars		185		185
Commodity derivative differential swaps		11,693		11,693
Total liabilities	$	$ 27,714	$	$ 27,714

4. Risk Management and Derivative Instruments

The Company s production is exposed to fluctuations in crude oil, NGL and natural gas prices. The Company believes it is prudent to manage the variability in cash flows by entering into derivative financial instruments to economically hedge a portion of its crude oil, NGL and natural gas production. The Company utilizes various types of derivative financial instruments, including swaps and collars, to reduce fluctuations in cash flows resulting from changes in commodity prices. These derivative contracts are placed with major financial institutions that the Company believes are minimal credit risks. The oil, NGL and natural gas reference prices, upon which the commodity derivative contracts are based, reflect various market indices that management believes have a high degree of historical correlation with actual prices received by the Company for its crude oil, NGL and natural gas production.

Inherent in the Company s portfolio of commodity derivative contracts are certain business risks, including market risk and credit risk. Market risk is the risk that the price of the commodity will change, either favorably or unfavorably, in response to changing market conditions. Credit risk is the risk of loss from nonperformance by the Company s counterparty to a contract. The Company does not require collateral from its counterparties but does attempt to minimize its credit risk associated with derivative instruments by entering into derivative instruments only with counterparties that are large financial institutions, which management believes present minimal credit risk. In addition, to mitigate its risk of loss due to default, the Company has entered into agreements with its counterparties on its derivative instruments that allow the Company to offset its asset position

Table of Contents

with its liability position in the event of default by the counterparty. Due to the netting arrangements, had the Company s counterparties failed to perform under existing commodity derivative contracts, the maximum loss at September 30, 2013 would have been approximately $4.1 million.

Commodity Derivative Contracts

As of September 30, 2013, the Company had the following open commodity derivative contract positions:

	Hedged Volume	Weighted-Average Fixed Price			
Oil (Bbls):					
WTI Swaps 2013	1,086,120				$ 94.32
WTI Swaps 2014	4,344,450				$ 88.76
WTI Swaps 2015	1,820,000				$ 86.55
WTI Collars 2013	50,751	$	85.27	-	$ 100.70
WTI Collars 2014	164,400	$	88.49	-	$ 97.94
WTI to LLS Basis Differential Swaps 2013 (1)	330,760				$ 5.80
WTI to LLS Basis Differential Swaps 2014 (1)	501,000				$ 5.35
Natural Gas (Mmbtu):					
Swaps 2013 (2)	3,680,000				$ 4.09
Swaps 2014	9,125,000				$ 4.23
Collars 2013	558,249	$	3.68	-	$ 4.91
Collars 2014	1,685,004	$	3.99	-	$ 5.09
NGL (Bbls):					
NGL Swaps 2013	64,500				$ 63.42
NGL Swaps 2014	151,500				$ 62.16

(1) The Company enters into swap arrangements intended to fix the positive differential between the Louisiana Light Sweet (LLS) pricing and West Texas Intermediate (NYMEX WTI) pricing.

(2) Includes 1,240,000 Mmbtu that priced in the third quarter of 2013, but have yet to be cash settled as of September 30, 2013.

Table of Contents

Balance Sheet Presentation

The following table summarizes the gross fair values of derivative instruments by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company s unaudited condensed consolidated balance sheets at September 30, 2013 and December 31, 2012, respectively (in thousands):

Type	Balance Sheet Location (1)		September 30, 2013	December 31, 2012
Oil Swaps	Derivative financial instruments	Current Assets	$ 4,405	$ 16,004
Oil Swaps	Derivative financial instruments	Non-Current Assets	27	129
Oil Swaps	Derivative financial instruments	Current Liabilities	(35,941)	(11,485)
Oil Swaps	Derivative financial instruments Liabilities	Non-Current	(7,138)	(3,606)
NGL Swaps	Derivative financial instruments	Current Assets	1,345	1,624
NGL Swaps	Derivative financial instruments	Non-Current Assets		729
NGL Swaps	Derivative financial instruments	Current Liabilities	(54)	(336)
NGL Swaps	Derivative financial instruments Liabilities	Non-Current		(122)
Gas Swaps	Derivative financial instruments	Current Assets	3,746	
Gas Swaps	Derivative financial instruments	Non-Current Assets	548	
Oil Collars	Derivative financial instruments	Current Assets	28	221
Oil Collars	Derivative financial instruments	Non-Current Assets	40	207
Oil Collars	Derivative financial instruments	Current Liabilities	(460)	(238)
Oil Collars	Derivative financial instruments Liabilities	Non-Current	(36)	(49)
Gas Collars	Derivative financial instruments	Current Assets	1,308	1,129
Gas Collars	Derivative financial instruments	Non-Current Assets	41	897
Gas Collars	Derivative financial instruments	Current Liabilities	(18)	(112)
Gas Collars	Derivative financial instruments Liabilities	Non-Current	(3)	(73)
Basis Differential Swaps	Derivative financial instruments	Current Assets	1,163	2,625
Basis Differential Swaps	Derivative financial instruments	Non-Current Assets	91	36
Basis Differential Swaps	Derivative financial instruments	Current Liabilities	(202)	(11,319)
Basis Differential Swaps	Derivative financial instruments Liabilities	Non-Current		(374)
Total			$ (31,110)	$ (4,113)

(1) The fair values of commodity derivative instruments reported in the Company s condensed consolidated balance sheets are subject to netting arrangements and qualify for net presentation. The following table summarizes the location and fair value amounts of all derivative instruments in the unaudited condensed consolidated balance sheets, as well as the gross recognized derivative assets, liabilities and amounts offset in the unaudited condensed consolidated balance sheets at September 30, 2013 and December 31, 2012, respectively (in thousands):

		September 30, 2013		
Not Designated as ASC 815 Hedges:	Balance Sheet Classification	Gross Recognized Assets/ Liabilities	Gross Amounts Offset	Net Recognized Fair Value Assets/ Liabilities
Derivative assets:				
Commodity contracts	Derivative financial instruments - current	$ 11,995	$ 8,212	$ 3,783
Commodity contracts	Derivative financial instruments - noncurrent	747	447	300
		$ 12,742	$ 8,659	$ 4,083
Derivative liabilities:				
Commodity contracts	Derivative financial instruments - current	$ 36,675	$ 8,212	$ 28,463
Commodity contracts	Derivative financial instruments - noncurrent	7,177	447	6,730

		$	43,852	$	8,659	$	35,193

		December 31, 2012					
Not Designated as ASC 815 Hedges:	**Balance Sheet Classification**	**Gross Recognized Assets/ Liabilities**		**Gross Amounts Offset**		**Net Recognized Fair Value Assets/ Liabilities**	
Derivative assets:							
Commodity contracts	Derivative financial instruments - current	$	21,603	$	15,908	$	5,695
Commodity contracts	Derivative financial instruments - noncurrent		1,998		281		1,717
		$	23,601	$	16,189	$	7,412
Derivative liabilities:							
Commodity contracts	Derivative financial instruments - current	$	23,490	$	15,908	$	7,582
Commodity contracts	Derivative financial instruments - noncurrent		4,224		281		3,943
		$	27,714	$	16,189	$	11,525

Table of Contents

Gains (losses) on Commodity Derivative Contracts

The Company does not designate its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, commodity derivative contracts are marked-to-market each quarter with the change in fair value during the periodic reporting period recognized currently as a gain or loss in Losses on commodity derivative contracts - net within revenues in the unaudited condensed consolidated statements of operations. Realized gains and losses represent the actual settlements under commodity derivative contracts that require making a payment to or receiving a payment from the counterparty, as well as any deferred premiums payable to the counterparty upon contract settlement. During the three and nine months ended September 30, 2012, the Company paid deferred premiums of $0.8 million and $2.5 million related to put options covering a total of 138,000 and 411,000 barrels of crude oil, respectively.

The following table presents realized net losses and unrealized net (losses) gains recorded by the Company related to the change in fair value of the derivative instruments in Gains (losses) on commodity derivative contracts net for the periods presented:

	For the Three Months Ended September 30, 2013	2012	For the Nine Months Ended September 30, 2013	2012
	(in thousands)			
Realized net losses	$ (9,927)	$ (4,160)	$ (16,002)	$ (15,840)
Unrealized net (losses) gains	(35,369)	(29,566)	(26,997)	5,591

5. Property and Equipment

	September 30, 2013	December 31, 2012
	(in thousands)	
Oil and gas properties, on the basis of full-cost accounting:		
Proved properties	$ 2,488,680	$ 1,522,723
Unevaluated properties	425,742	313,941
Other property and equipment	10,029	5,038
Less accumulated depreciation, depletion, and amortization	(443,852)	(274,294)
Net property and equipment	$ 2,480,599	$ 1,567,408

Oil and Gas Properties

For the three and nine months ended September 30, 2013, the Company capitalized $2.9 million and $6.2 million, respectively, of internal costs directly related to exploration and development activities to oil and gas properties. Note that these amounts are inclusive of $0.5 million and $1.1 million of qualifying share based compensation expense (as discussed in Note 10) for the three and nine months ended September 30, 2013, respectively.

For the three and nine months ended September 30, 2012, the Company capitalized $0.5 million and $0.9 million, respectively, of internal costs to oil and gas properties. Note that these amounts are inclusive of $0.1 million and $0.1 million of qualifying share based compensation expense (as discussed in Note 10) for the three and nine months ended September 30, 2012, respectively.

The Company accounts for its oil and gas properties under the full cost method. Under the full cost method, proceeds from the sale or disposition of oil and gas properties are accounted for as a reduction to capitalized costs unless a significant portion of the Company s reserve quantities are sold that results in a significant alteration of the relationship between capitalized costs and remaining proved reserves, in which case a gain or loss is generally recognized in income.

The Company performs a ceiling test on a quarterly basis. The test establishes a limit (ceiling) on the book value of oil and gas properties. The capitalized costs of oil and gas properties, net of accumulated DD&A and the related deferred income taxes, may not exceed this ceiling. The ceiling limitation is equal to the sum of: (i) the present value of estimated future net revenues from the projected production of proved oil and gas reserves, excluding future cash outflows associated with settling asset retirement obligations (ARO) accrued on the balance sheet, calculated using the average oil and natural gas sales price received by the Company as of the first trading day of each month over the preceding twelve months (such prices are held constant throughout the life of the properties) and a discount factor of 10%; (ii) the cost of unproved and unevaluated properties excluded from the costs being amortized; (iii) the lower of cost or estimated fair value of unproved properties included in the costs being amortized; and (iv) related income tax effects. If capitalized costs exceed this ceiling, the excess is charged to expense in the accompanying consolidated statements of operations.

At September 30, 2013 and 2012, capitalized costs did not exceed the ceiling, and no impairment to oil and gas properties was required; however, the Company s ceiling test calculation at September 30, 2013 indicated the Company s capitalized costs were within 5% of the ceiling.

Depreciation, depletion and amortization is calculated using the Units of Production Method (UOP). The UOP calculation multiplies the percentage of estimated proved reserves produced by the cost of those reserves. The result is to recognize expense at the same pace that the reservoirs are estimated to be depleting. The amortization base in the UOP calculation includes the sum of proved property costs net of accumulated

Table of Contents

depreciation, depletion and amortization (DD&A), estimated future development costs (future costs to access and develop proved reserves) and asset retirement costs that are not already included in oil and gas property, less related salvage value. The following table presents depletion expense related to oil and gas properties for the three and nine months ended September 30, 2013 and 2012:

	For the Three Months Ended September 30, 2013		For the Three Months Ended September 30, 2012		For the Nine Months Ended September 30, 2013		For the Nine Months Ended September 30, 2012	
Depletion expense (in thousands)	$	74,345	$	30,571	$	168,190	$	86,303
Depletion expense (per Boe)	$	28.39	$	40.60	$	28.68	$	38.79

Oil and gas unevaluated properties and properties under development include costs that are not being depleted or amortized. These costs represent investments in unproved properties. The Company excludes these costs until proved reserves are found, until it is determined that the costs are impaired or until major development projects are placed in service, at which time the costs are moved into oil and natural gas properties subject to amortization. All unproved property costs are reviewed at least quarterly to determine if impairment has occurred. Unevaluated property was $425.7 million at September 30, 2013 compared to $313.9 million at December 31, 2012, increasing primarily due to the Anadarko Basin Acquisition which is discussed further below.

Other Property and Equipment

Other property and equipment consists of vehicles, furniture and fixtures, and computer hardware and software and are carried at cost. Depreciation is calculated principally using the straight-line method over the estimated useful lives of the assets, which range from five to seven years. Maintenance and repairs are charged to expense as incurred, while renewals and betterments are capitalized.

Eagle Property Acquisition October 2012

On October 1, 2012, the Company closed on the Eagle Property Acquisition. The assets acquired include certain interests in producing oil and natural gas assets and unevaluated leasehold acreage in Oklahoma and Kansas and related hedging instruments. The Company s results from operations include the results from the properties acquired in the Eagle Property Acquisition beginning October 1, 2012. The fair value of, and the allocation to, the assets acquired and liabilities assumed in the Eagle Property Acquisition, has been finalized and is shown in the following table (in thousands):

	Eagle Property Acquisition	
Oil and gas properties:		
Proved	$	419,549
Unevaluated		244,236
Commodity derivative contracts		8,453
Total assets acquired	**$**	**672,238**

Asset retirement obligations		2,662
Deferred income tax liabilities		25,985
Commodity derivative contracts		
Total liabilities assumed	**$**	**28,647**
Net assets acquired	**$**	**643,591**

The finalized balances in the table above include immaterial changes to the amounts originally allocated to oil and gas properties and deferred income tax liabilities. These changes were required to reflect the final consideration paid after adjustment for certain post-closing purchase price amounts.

Anadarko Basin Acquisition May 2013

On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash (before customary post-closing adjustments). The Company funded the purchase price of the Anadarko Basin Acquisition with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021, which also closed on May 31, 2013.

The transaction was accounted for using the acquisition method of accounting which requires, among other things, that assets acquired and liabilities assumed be recognized at their fair values as of the acquisition date. The final determination of fair value for certain assets and liabilities remains preliminary and will be completed after post-closing purchase price adjustments are finalized no later than one year from the acquisition date.

Table of Contents

Since June 30, 2013 the Company has recorded adjustments to the purchase price to reduce the amounts allocated to proved and unproved properties by $1.0 million and $0.4 million, respectively. The following table reflects the adjusted allocation as of September 30, 2013 (in thousands):

		Anadarko Basin Acquisition
Oil and gas properties		
Proved	$	416,239
Unevaluated		206,989
Total assets acquired	**$**	**623,228**
Asset retirement obligations		6,296
Total liabilities assumed	**$**	**6,296**
Net assets acquired	**$**	**616,932**

Actual and Pro Forma Information

Revenues attributable to the Eagle Property Acquisition and Anadarko Basin Acquisition included in the Company s unaudited condensed consolidated statements of operations for the three months ended September 30, 2013 were $69.3 million and $45.6 million, respectively. Revenues attributable to the Eagle Property Acquisition and Anadarko Basin Acquisition included in the Company s unaudited condensed consolidated statements of operations for the nine months ended September 30, 2013 were $152.5 million and $59.8 million, respectively.

The following table presents unaudited pro forma information for the Company as if the Eagle Property Acquisition and the Anadarko Basin Acquisition occurred on January 1, 2012 (the three and nine month periods ended September 30, 2013 are adjusted for the Anadarko Basin Acquisition only, as the effect of the Eagle Property Acquisition is included in the Company s historical results for these periods, and the effect of the Anadarko Basin Acquisition was not included in the Company s results until May 31, 2013):

		For the Three Months Ended September 30, 2012		For the Nine Months Ended September 30, 2013		For the Nine Months Ended September 30, 2012
Revenues and other	$	85,606	$	378,591	$	360,913
Net income (loss)		(15,790)		(21,401)		(136,656)
Preferred stock dividends		(6,500)		(9,254)		(19,500)
Income (loss) available to common shareholders	$	(22,290)	$	(30,655)	$	(156,156)
Net loss per common share - basic	$	(0.34)	$	(0.47)	$	(2.69)
Net loss per common share - diluted	$	(0.34)	$	(0.47)	$	(2.69)

The historical financial information was adjusted to give effect to the pro forma events that were directly attributable to the Eagle Property Acquisition and the Anadarko Basin Acquisition and are factually supportable. The unaudited pro forma consolidated results are not necessarily indicative of what the Company s consolidated results of operations actually would have been had the acquisitions been completed on January 1, 2012. In addition, the unaudited pro forma consolidated results do not purport to project the future results of operations for the combined

Company.

6. Other Noncurrent Assets

At September 30, 2013, other noncurrent assets consisted of $47.2 million in deferred financing costs, $10.5 million in field inventory, and $0.2 million in other noncurrent assets.

At December 31, 2012, other noncurrent assets consisted of $25.2 million in deferred financing costs and $0.2 million in other noncurrent assets.

7. Asset Retirement Obligations

AROs represent the future abandonment costs of tangible assets, such as wells, service assets and other facilities. The fair value of the ARO at inception is capitalized as part of the carrying amount of the related long-lived assets. AROs approximated $23.2 million and $15.2 million as of September 30, 2013 and December 31, 2012, respectively, and the liability has been accreted to its present value as of September 30, 2013 and December 31, 2012. The Company evaluated its wells and determined a range of abandonment dates through 2071.

Table of Contents

The following table reflects the changes in the Company s AROs for the nine months ended September 30, 2013 (in thousands):

Asset retirement obligations at January 1, 2013	**$**	**15,245**
Liabilities incurred		710
Liabilities assumed in Anadarko Basin Acquisition		6,296
Revisions		
Liabilities settled		(61)
Current period accretion expense		988
Asset retirement obligations at September 30, 2013	**$**	**23,178**

8. Accrued Liabilities

Accrued liabilities at September 30, 2013 consisted of $69.3 million in oil and gas capital expenditures, $53.8 million in accrued interest, $45.0 million in accrued revenue and royalty distributions, $9.5 million in accrued taxes, and $21.1 million in other accrued liabilities.

Accrued liabilities at December 31, 2012 consisted of $69.0 million in oil and gas capital expenditures, $16.2 million in accrued interest and $13.4 million in other accrued liabilities.

9. Long-Term Debt

The Company s long-term debt as of September 30, 2013 and December 31, 2012 is as follows (in thousands):

		September 30, 2013		December 31, 2012
Revolving credit facility, due 2018	$	306,150	$	94,000
Senior notes, due 2020		600,000		600,000
Senior notes, due 2021		700,000		
Long-term debt	**$**	**1,606,150**	**$**	**694,000**

Reserve-based Credit Facility

As of September 30, 2013, the Company s credit facility consisted of a $750 million senior revolving credit facility (the Credit Facility) with a borrowing base of $500 million, as recently redetermined on September 26, 2013, when the borrowing base was increased from $425 million. At September 30, 2013, outstanding letters of credit obligations total $0.2 million.

The Credit Facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of the Company s oil and natural gas properties and currently bear interest at LIBOR plus an applicable margin, depending upon the Company s borrowing base utilization, between 1.75% and 2.75% per annum. At September 30, 2013 and December 31, 2012, the weighted average interest rate was 2.5% and 2.9%, respectively.

In addition to interest expense, the Credit Facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of either 0.375% or 0.50% per annum based on the average daily amount by which the borrowing base exceeds the outstanding borrowings during each quarter.

The borrowing base under the Credit Facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by the Company or the administrative agent, acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations. The next scheduled borrowing base redetermination date is April 1, 2014.

Under the terms of the Credit Facility, the Company is required to repay the amount by which the principal balance of its outstanding loans and its letter of credit obligations exceed its redetermined borrowing base. The Company is permitted to make such repayment in six equal successive monthly payments commencing 30 days following the administrative agent s notice regarding such borrowing base reduction.

On September 26, 2013, the Company entered into the Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement among the Company, as parent, Midstates Sub, as borrower, SunTrust Bank as administrative agent, and the other lenders and parties party thereto (the Fourth Amendment).

The Fourth Amendment amended the Credit Facility to provide that the Company s ratio of total net indebtedness to EBITDA for the trailing four fiscal quarter period ending on the last day of such fiscal quarter cannot exceed (i) 4.75:1.0, for the fiscal quarters ending September 30, 2013, December 31, 2013 and March 31, 2014, (ii) 4.50:1.0, for the fiscal quarters ending June 30, 2014, (iii) 4.25:1.0, for the fiscal quarters ending September 30, 2014 and December 31, 2014, and (iv) 4.00:1.0, for the fiscal quarter ending March 31, 2015 and each fiscal quarter thereafter. The Company also agreed to pay a one-time fee of 0.50% to each lender on the portion of their commitment to the borrowing base under the Fourth Amendment in excess of their commitment prior to the Fourth Amendment, and a one-time fee of 0.10% to each lender on the lesser of such lenders commitment immediately prior to, or after giving effect to, the Fourth Amendment.

Table of Contents

The Credit Facility contains financial covenants, in addition to the maximum ratio of debt to EBITDA discussed above, which, among other things, set a minimum current ratio (as defined therein) of not less than 1.0 to 1.0 and various other standard affirmative and negative covenants including, but not limited to, restrictions on the Company s ability to make any dividends, distributions or redemptions.

As of September 30, 2013, the Company was in compliance with the minimum current ratio and the ratio of debt to EBITDA covenants as set forth in the Credit Facility. The Company s current ratio at September 30, 2013 was 1.5 to 1.0. At September 30, 2013, the Company s ratio of debt to EBITDA was 4.4 to 1.0.

Based upon the recent amendments to the Credit Facility, the Company believes its carrying amount at September 30, 2013 approximates its fair value (Level 2) due to the variable nature of the applicable interest rate and current financing terms available to the Company.

2020 Senior Notes

On October 1, 2012, the Company issued $600 million in aggregate principal amount of 10.75% senior notes due 2020 (the 2020 Outstanding Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the Securities Act). On October 29, 2013, substantially all of the 2020 Outstanding Notes were exchanged for an equal principal amount of registered 10.75% senior subordinated notes due 2020 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the 2020 Exchange Notes). The 2020 Exchange Notes are identical to the 2020 Outstanding Notes except that the 2020 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-Q, the term 2020 Senior Notes refers to both the 2020 Outstanding Notes and the 2020 Exchange Notes. The 2020 Senior Notes were co-issued on a joint and several basis by the Company and its wholly owned subsidiary, Midstates Sub. The Company does not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries of the Company. The 2020 Senior Notes Indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to the Company or limit the ability of the Company to advance loans to Midstates Sub.

At any time prior to October 1, 2015, the Company may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes with the net proceeds of a public or private equity offering at a redemption price of 110.75% of the principal amount of the 2020 Senior Notes, plus any accrued and unpaid interest up to the redemption date. In addition, at any time before October 1, 2016, the Company may redeem all or a part of the 2020 Senior Notes at a redemption price equal to 100% of the principal amount of 2020 Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, up to, the redemption date. On or after October 1, 2016, the Company may redeem all or a part of the 2020 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the Indenture plus accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, on the 2020 Senior Notes redeemed, up to, the redemption date.

The Indenture contains covenants that, among other things, restrict the Company s ability to: (i) incur additional indebtedness, guarantee indebtedness or issue certain preferred shares; (ii) make loans, investments and other restricted payments; (iii) pay dividends on or make other distributions in respect of, or repurchase or redeem, capital stock; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with the Company s affiliates; (vii) consolidate, merge or sell substantially all of the Company s assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business the Company conducts and (x) enter into agreements restricting the ability of the Company s current and any future subsidiaries to pay dividends.

Upon the occurrence of certain change of control events, as defined in the Indenture, each holder of the 2020 Senior Notes will have the right to require that the Company repurchase all or a portion of such holder s 2020 Senior Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase. In connection with the private placement of the 2020 Senior Notes, on October 1, 2012, the Company entered into a registration rights agreement (the 2020 Notes Registration Rights Agreement) obligating the Company to use reasonable best efforts to file an exchange registration statement with the Securities and Exchange Commission (the Commission) so that holders of the 2020 Senior Notes can offer to exchange the 2020 Senior Notes for registered notes having substantially the same terms as the 2020 Senior Notes and evidencing the same indebtedness as the 2020 Senior Notes.

The estimated fair value of the 2020 Senior Notes was $627.0 million as of September 30, 2013 (Level 2 in the fair value measurement hierarchy based on the limited trading volume on the secondary market), based on quoted market prices for these same debt securities. The effective annual interest rate for the 2020 Senior Notes was approximately 11.1% for the three and nine months ended September 30, 2013.

2021 Senior Notes

On May 31, 2013, the Company issued $700 million in aggregate principal amount of 9.25% senior notes due 2021 (the 2021 Outstanding Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. On October 29, 2013, all of the 2021 Outstanding Notes were exchanged for an equal principal amount of registered 9.25% senior subordinated notes due 2021 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the 2021 Exchange Notes). The 2021 Exchange Notes are identical to the 2021 Outstanding Notes except that the 2021 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-Q, the term 2021 Senior Notes refers to both the 2021 Outstanding Notes and the 2021 Exchange Notes. The proceeds from the offering of $700 million (net of the initial purchasers discount and related offering expenses) were used to fund the Anadarko Basin Acquisition and the related expenses, to pay the expenses related to an amendment to the Company s revolving credit facility, to repay $34.3 million in outstanding borrowings under the Company s Credit Facility, and for general corporate purposes.

Table of Contents

The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes.

The 2021 Senior Notes were co-issued on a joint and several basis by the Company and its wholly owned subsidiary, Midstates Sub. The Company does not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries of the Company. The 2021 Senior Notes indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to the Company or limit the ability of the Company to advance loans to Midstates Sub.

On or prior to May 31, 2014, the Company may redeem up to $100.0 million of aggregate principal amount of the 2021 Senior Notes with the net cash proceeds from any Equity Offerings (as such term is defined in the 2021 Senior Notes Indenture) at a redemption price equal to 103% of the principal amount plus accrued and unpaid interest.

Prior to June 1, 2016, the Company may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes (less the amount of 2021 Senior Notes redeemed pursuant to the preceding paragraph) with the net proceeds of any Equity Offerings at a redemption price of 109.25% of the principal amount of the 2021 Senior Notes redeemed, plus any accrued and unpaid interest, if any, up to the redemption date. In addition, at any time before June 1, 2016, the Company may redeem all or a part of the 2021 Senior Notes at a redemption price equal to 100% of the principal amount of the 2021 Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, up to, the redemption date. On or after October 1, 2016, the Company may redeem all or a part of the 2021 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2021 Senior Notes Indenture plus accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, on the 2021 Senior Notes redeemed, up to, the redemption date.

The terms of the covenants and change in control provisions in the 2021 Senior Notes Indenture are substantially identical to those of the 2020 Senior Notes discussed above. Additionally the Company entered into a registration rights agreement (the 2021 Notes Registration Rights Agreement) with provisions substantially identical to that of the 2020 Notes Registration Rights Agreement.

The estimated fair value of the 2021 Senior Notes was $701.8 million as of September 30, 2013 (Level 2 in the fair value measurement hierarchy based on the limited trading volume on the secondary market), based on quoted market prices for these same debt securities. The effective annual interest rate for the 2021 Senior Notes was approximately 9.4% and 9.5% for the three and nine months ended September 30, 2013, respectively.

10. Equity and Share-Based Compensation

Common and Preferred Shares

On April 24, 2012, in connection with the Company s initial public offering, a corporate reorganization occurred and each common unit of Holdings LLC was converted into approximately 185.5 common shares of the Company and as a result, the Company issued 47,634,353 shares of its common stock to the unitholders of Holdings LLC.

On April 25, 2012, the Company completed its initial public offering of common stock pursuant to a registration statement on Form S-1 (File 333-177966), as amended and declared effective by the SEC on April 19, 2012. Pursuant to the registration statement, the Company registered the offer and sale of 27,600,000 shares of $0.01 par value common stock, which included 6,000,000 shares of common stock sold by the selling shareholders and 3,600,000 shares of common stock sold by the selling shareholders pursuant to an option granted to the underwriters to cover over-allotments.

After the corporate reorganization and the completion of its initial public offering discussed above, the Company is authorized to issue up to a total of 300,000,000 shares of its common stock with a par value of $0.01 per share, and 50,000,000 shares of its preferred stock with a par value of $0.01 per share. Holders of the Company s common shares are entitled to one vote for each share held of record on all matters submitted to a vote of stockholders and to receive ratably in proportion to the shares of common stock held by them any dividends declared from time to time by the board of directors. The common shares have no preferences or rights of conversion, exchange, pre-exemption or other subscription rights.

With respect to preferred shares, the Company is authorized, without further stockholder approval, to establish and issue from time to time one or more classes or series of preferred stock with such powers, preferences, rights, qualifications, limitations and restrictions as determined by its board of directors.

Series A Preferred Stock

In connection with the Eagle Property Acquisition, on September 28, 2012, the Company designated 325,000 shares of Series A Mandatorily Convertible Preferred Stock (the Series A Preferred Stock) with an initial liquidation preference of $1,000 per share and an 8% per annum dividend, payable semiannually at the Company s option in cash or through an increase in the liquidation preference. The Series A Preferred Shares are convertible after October 1, 2013, in whole but not in part and at the option of the holders of a majority of the outstanding shares of Series A Preferred Stock, into a number shares of the Company s common stock calculated by dividing the then-current liquidation preference by the conversion price of $13.50 per share and, if not previously converted, are mandatorily convertible at September 30, 2015 into shares of the Company s common stock at a conversion price no greater than $13.50 per share and no less than $11.00 per share, with the ultimate conversion price dependent upon the volume weighted average price of the Company s common stock during the 15 trading days immediately prior to September 30, 2015. The Series A Preferred Stock was issued on October 1, 2012.

Table of Contents

On March 30, 2013, the Company elected to pay the $13 million semi-annual dividend due on that date through an increase in the Series A Preferred Stock liquidation preference to $1,040. As a result, the Company will be obligated to issue between 962,963 and 1,181,818 additional shares of common stock upon conversion of the Series A Preferred Stock, with the ultimate number of shares dependent upon the conversion price then in effect as described above.

On September 30, 2013, the Company elected to pay the $13.5 million semi-annual dividend due on that date through an increase in the Series A Preferred Stock liquidation preference to $1,082. As a result, the Company will be obligated to issue between 1,001,481 and 1,229,091 additional shares of common stock upon conversion of the Series A Preferred Stock, with the ultimate number of shares dependent upon the conversion price then in effect as discussed above.

For the three months ended September 30, 2013, the $2.6 million Series A Preferred Stock dividend was based upon the estimated fair value of 500,741 common shares that would have been issued on the semi-annual dividend due date had the notional dividend amount of $6.8 million been converted into common shares at a conversion price of $13.50 per share.

For the nine months ended September 30, 2013, the $9.3 million Series A Preferred Stock dividend was based upon the estimated fair value of 481,481 and 1,001,481 common shares that would have been issued on the semi-annual dividend dates of March 30, 2013 and September 30, 2013 had the notional dividend amounts of $6.5 million and $13.5 million, respectively, been converted into common shares at a conversion price of $13.50 per share.

Share Activity

The following table summarizes changes in the number of outstanding shares since December 31, 2012:

	Number of Shares		
	Series A Preferred Stock	Common Stock	Treasury Stock
Share count as of December 31, 2012	325,000	66,619,711	
Grants of restricted stock		2,163,959	
Forfeitures of restricted stock		(97,414)	
Acquisition of treasury stock			(107,058)
Share count as of September 30, 2013	**325,000**	**68,686,256**	**(107,058)**

The Company s 2012 LTIP (discussed below) allows for the recipients of restricted stock to surrender a portion of their shares upon vesting to satisfy Federal Income Tax (FIT) withholding requirements. The Company then remits to the IRS the cash equivalent of the FIT withholding liability. Shares surrendered to the Company in this fashion have been treated as treasury shares acquired at a cost equivalent to the related tax liability. These shares are available for future issuance by the Company.

Incentive Units

At September 30, 2013, 1,596 incentive units were issued and outstanding. These incentive units were issued prior to the Company s initial public offering. In connection with the corporate reorganization that occurred immediately prior to our initial public offering, these incentive units held in the Company were contributed to FR Midstates Interholding, LP (FRMI) in exchange for incentive units in FRMI. Holders of FRMI incentive units will receive, out of proceeds otherwise distributable to FRMI, a percentage interest in the amounts distributed to FRMI in excess of certain multiples of FRMI s aggregate capital contributions and investment expenses (FRMI Profits). Although any future payments to the incentive unit holders will be made out of the proceeds otherwise distributable to FRMI and not by the Company, the Company will be required to record a non-cash compensation charge in the period any payment is made related to the FRMI incentive units. To date, no compensation expense related to the incentive units has been recognized by the Company, as any payout under the incentive units is not considered probable, and thus, the amount of FRMI Profits, if any, cannot be determined.

Share-based Compensation, Post-Initial Public Offering

2012 Long Term Incentive Plan

On April 20, 2012, the Company established the 2012 Long Term Incentive Plan (the 2012 LTIP) and filed a Form S-8 with the SEC, registering 6,563,435 shares of common stock for future issuance under the terms of the 2012 LTIP. The 2012 LTIP provides a means for the Company to attract and retain employees, directors and consultants, and a method whereby employees, directors and consultants of the Company who contribute to its success can acquire and maintain stock ownership or awards, the value of which is tied to the performance of the Company, thereby strengthening their concern for the welfare of the Company and their desire to remain employed.

The 2012 LTIP provides for the granting of Options (Incentive and other), Restricted Stock Awards, Restricted Stock Units, Stock Appreciation Rights, Dividend Equivalents, Bonus Stock, Other Stock-Based Awards, Annual Incentive Awards, Performance Awards, or any combination of the foregoing (the Awards). Subject to certain limitations as defined in the 2012 LTIP, the terms of each Award are as determined by the Compensation Committee of the Board of Directors. A total of 6,563,435 common share Awards are authorized for issuance under the 2012 LTIP and

Table of Contents

shares of stock subject to an Award that expire, or are canceled, forfeited, exchanged, settled in cash or otherwise terminated, will again be available for future Awards under the 2012 LTIP.

Non-vested Stock Awards

Subsequent to the completion of the Company s initial public offering and pursuant to the 2012 LTIP, through September 30, 2013, the Company had 2,758,415 non-vested shares of restricted common stock to directors, management and employees outstanding. Shares granted under the LTIP generally vest ratably over a period of three years (one-third on each anniversary of the grant); however, beginning in 2013, shares granted under the 2012 LTIP to directors are subject to one-year cliff vesting.

The fair value of restricted stock grants is based on the value of the Company s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. The Company has assumed no annual forfeiture rate due to limited historical experience with turnover associated with this type of award.

The following table summarizes the Company s non-vested share award activity for the nine months ended September 30, 2013:

	Shares		Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2012	985,358	$	12.61
Granted	2,163,959	$	7.14
Vested	(293,488)	$	13.10
Forfeited	(97,414)	$	8.48
Non-vested shares outstanding at September 30, 2013	**2,758,415**	**$**	**8.41**

Unrecognized expense as of September 30, 2013 for all outstanding restricted stock awards was $18.3 million and will be recognized over a weighted average period of 2.1 years.

At September 30, 2013, 3,805,020 shares remain available for issuance under the terms of the 2012 LTIP.

The following table summarizes share-based compensation costs (after amounts capitalized to oil and gas properties) recognized as expense by the Company for the periods presented (in thousands):

	For the Three Months Ended September 30,	For the Nine Months Ended September 30,

	2013	2012	2013	2012
Incentive units	$	$	$	$
2012 LTIP restricted shares	1,908	886	4,921	1,568
Total share-based compensation expense	$ 1,908	$ 886	$ 4,921	$ 1,568

For the three and nine months ended September 30, 2013, the Company capitalized $0.5 million and $1.1 million, respectively, of qualifying share-based compensation costs to oil and gas properties. For the three and nine months ended September 30, 2012, the Company capitalized $0.1 million and $0.1 million, respectively, of qualifying share-based compensation costs to oil and gas properties.

11. Income Taxes

Prior to its corporate reorganization (See Note 1), the Company was a limited liability company and not subject to federal income tax or state income tax (in most states). Accordingly, no provision for federal or state income taxes was recorded prior to the corporate reorganization as the Company s equity holders were responsible for income tax on the Company s profits. In connection with the closing of the Company s initial public offering, the Company merged into a corporation and became subject to federal and state income taxes.

Consistent with the applicable guidance, the Company revises its estimate of its annual income tax rate each quarter, and reflects this change in estimate on year-to-date activity in each quarter.

For the nine months ended September 30, 2013, the Company estimated its effective annual tax rate for 2013 to be a benefit of approximately 36.5%. The Company s estimated effective tax rate for 2013 differs from the federal statutory rate of 35% due largely to state income taxes. The revision in annual estimate is primarily attributable to recording a discrete item in the quarter related to certain share-based compensation expense events. The Company expects to incur a tax loss in the current year (due principally to the ability to expense certain intangible drilling and development costs under current law) and thus no current income taxes are anticipated to be paid. This tax loss is expected to result in a net operating loss carryforward at year-end; however, no valuation allowance has been recorded as management believes that there is sufficient future taxable income to fully utilize all tax attributes. This future taxable income arises from reversing temporary differences due to the excess of the book carrying value

Table of Contents

of oil and gas properties over their corresponding tax bases. Management is not relying on other sources of taxable income in concluding that no valuation allowance is needed. Management does not presently believe that our tax loss carryforwards are limited in future usage.

The components of the Company s deferred taxes at September 30, 2013 and at December 31, 2012 (inclusive of the tax correction discussed in Note 2) are detailed in the table below (in thousands):

		September 30, 2013		December 31, 2012
Deferred tax assets - current				
Derivative instruments and other	$	16,196	$	6,027
Deferred tax assets - noncurrent				
US tax loss carryforwards		110,283(1)		90,735
State tax loss carryforwards		19,794(1)		12,258
Employee benefit plans		360		985
Total deferred tax assets, noncurrent		130,437		103,978
Deferred tax liabilities - noncurrent				
Oil and gas properties and equipment		280,428		260,715
Total deferred tax liabilities, noncurrent		280,428		260,715
Reflected in the accompanying balance sheet as:				
Net deferred tax asset, current	$	16,196	$	6,027
Net deferred tax liability noncurrent	$	149,991	$	156,737

(1) Includes the impact of the correction discussed in Note 2.

At September 30, 2013, the Company has not recorded a reserve for any uncertain tax positions.

12. Loss Per Share

The Company s Series A Preferred Stock issued in connection with the Eagle Property Acquisition has the nonforfeitable right to participate on an as converted basis at the conversion rate then in effect in any common stock dividends declared and as such, is considered a participating security. The Company s nonvested stock awards, which are granted as part of the 2012 LTIP, contain nonforfeitable rights to dividends and as such, are considered to be participating securities and, together with the Series A Preferred Stock, are included in the computation of basic and diluted earnings (loss) per share, pursuant to the two-class method. In the calculation of basic earnings (loss) per share attributable to common shareholders, participating securities are allocated earnings based on actual dividend distributions received plus a proportionate share of undistributed net income attributable to common shareholders, if any, after recognizing distributed earnings. The Company s participating securities do not participate in undistributed net losses because they are not contractually obligated to do so.

The computation of diluted earnings per share attributable to common shareholders reflects the potential dilution that could occur if securities or other contracts to issue common shares that are dilutive were exercised or converted into common shares (or resulted in the issuance of common shares) and would then share in the earnings of the Company. During the periods in which the Company records a loss from continuing operations attributable to common shareholders, securities would not be dilutive to net loss per share and conversion into common shares is assumed to not occur. Diluted net income per share attributable to common shareholders is calculated under both the two-class method and the treasury stock method; the more dilutive of the two calculations is presented below.

The following table (in thousands, except per share amounts) provides a reconciliation of net losses to preferred shareholders, common shareholders, and participating securities for purposes of computing net loss per share for the three months ended September 30, 2013:

	Total	Series A Preferred Stock (1)	Common Stock	Non-vested Restricted Stock (2)
Net loss	$ (23,606)	$	$ (23,606)	$
Preferred Dividend	$ (2,569)		(2,569)	
Calculated allocation of net loss attributable to shareholders	$ (26,175)	$	$ (26,175)	$
Weighted average shares outstanding			65,821	
Net loss per share			$ (0.40)	

(1) Calculation of the preferred stock dividend is discussed in Note 10.

(2) As these shares are participating securities that participate in earnings, but are not required to participate in losses, this calculation demonstrates that there is not an allocation of the loss to the non-vested restricted stockholders.

Table of Contents

The following table (in thousands, except per share amounts) provides a reconciliation of net losses to preferred shareholders, common shareholders, and non-vested restricted shareholders for purposes of computing net loss per share for the three months ended September 30, 2012:

	Total	Series A Preferred Stock (1)	Common Stock	Non-vested Restricted Stock (2)
Net loss	$ (17,803)	$	$ (17,803)	$
Preferred Dividend	$			
Calculated allocation of net loss attributable to shareholders	$ (17,803)	$	$ (17,803)	$
Weighted average shares outstanding			65,634	
Net loss per share			$ (0.27)	

(1) There was not a preferred dividend for the three months ended September 30, 2012 as the Series A Preferred Stock were issued as part of the Eagle Property Acquisition which did not close until October 1, 2012.

(2) As these shares are participating securities that participate in earnings, but are not required to participate in losses, this calculation demonstrates that there is not an allocation of the loss to the non-vested restricted stockholders.

The following table (in thousands, except per share amounts) provides a reconciliation of net losses to preferred shareholders, common shareholders, and non-vested restricted shareholders for purposes of computing net loss per share for the nine months ended September 30, 2013:

	Total	Series A Preferred Stock (1)	Common Stock	Non-vested Restricted Stock (2)
Net loss	$ (28,217)	$	$ (28,217)	$
Preferred Dividend	$ (9,254)		(9,254)	
Calculated allocation of net loss attributable to shareholders	$ (37,471)	$	$ (37,471)	$
Weighted average shares outstanding			65,740	
Net loss per share			$ (0.57)	

(1) Calculation of the preferred stock dividend is discussed in Note 8.

(2) As these shares are participating securities that participate in earnings, but are not required to participate in losses, this calculation demonstrates that there is not an allocation of the loss to the non-vested restricted stockholders.

The following table (in thousands, except per share amounts) provides a reconciliation of net losses to preferred shareholders, common shareholders, and non-vested restricted shareholders for purposes of computing net income per share for the nine months ended September 30, 2012:

	Total	Series A Preferred Stock (1)	Common Stock	Non-vested Restricted Stock (2)
Net loss	$ (147,688)	$	$ (147,688)	$
Preferred Dividend	$			
Calculated allocation of net loss attributable to shareholders	$ (147,688)	$	$ (147,688)	$
Weighted average shares outstanding			58,080	
Net loss per share			$ (2.54)	

(1) There was not a preferred dividend for the nine months ended September 30, 2012 as the Series A Preferred Stock were issued as part of the Eagle Property Acquisition which did not close until October 1, 2012.

(2) As these shares are participating securities that participate in earnings, but are not required to participate in losses, this calculation demonstrates that there is not an allocation of the loss to the non-vested restricted stockholders.

The aggregate number of common shares outstanding at September 30, 2013 was 68,579,198, of which 2,758,415 were non-vested restricted shares. The aggregate number of shares of Series A Preferred Stock outstanding at September 30, 2013 was 325,000, each with a liquidation preference of $1,082 representing on an as-converted basis approximately 26.0 million common shares based upon a conversion price of $13.50 per share which have been excluded from the weighted average shares outstanding for EPS purposes due to their anti-dilutive effect.

Table of Contents

13. Commitments and Contingencies

Contractual Obligations

At September 30, 2013, contractual obligations for drilling contracts, long-term operating leases and seismic contracts are as follows (in thousands):

	Total	2013	2014	2015	2016 and beyond
Drilling contracts	$ 16,971	$ 13,874	$ 3,097	$	$
Non-cancellable office lease commitments	$ 9,132	390	1,580	1,601	5,561
Seismic contracts	$ 3,192	3,192			
Other	$ 2,696	2,696			
Net minimum commitments	$ 31,991	$ 20,152	$ 4,677	$ 1,601	$ 5,561

Commitments related to AROs are not included in the above table; see Note 7 for discussion of those commitments.

Litigation

Clovelly Oil Company

There has been no change in the action brought by Clovelly Oil Company against the Company since our last quarterly report on Form 10-Q for the quarter ended June 30, 2013.

Other

We are involved in other disputes or legal actions arising in the ordinary course of our business. We may not be able to predict the timing or outcome of these or future claims and proceedings with certainty, and an unfavorable resolution of one or more of such matters could have a material adverse effect on our financial condition, results of operations or cash flows. Currently, we are not party to any legal proceedings that, individually or in the aggregate, are reasonably expected to have a material adverse effect on our financial position, results of operations, or cash flows.

23

Table of Contents

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 our consolidated financial statements and notes thereto for the year ended December 31, 2012, and the related management s discussion and analysis contained in our annual report on Form 10-K dated and filed with the Securities and Exchange Commission (SEC) on March 21, 2013, as well as the unaudited condensed consolidated financial statements and notes thereto included in this quarterly report on Form 10-Q and in our quarterly reports on Form 10-Q for the quarterly periods ended March 31, 2013 and June 30, 2013.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Various statements contained in or incorporated by reference into this report are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the Securities Act) and Section 21E of the Securities Exchange Act of 1934 (the Exchange Act). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, and the plans, beliefs, expectations, intentions and objectives of management are forward-looking statements. When used in this quarterly report, the words could, believe, anticipate, intend, estimate, expect, may, continue, predict, potential, project, an are intended to identify forward looking statements, although not all forward looking statements contain such identifying words. In particular, the factors discussed in this report on Form 10-Q, our quarterly reports on Form 10-Q for the quarters ended March 31, 2013 and June 30, 2013, and detailed in our annual report filed on Form 10-K dated and filed with the SEC on March 21, 2013, could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;

- availability of oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;
- drilling of wells, including our identified drilling locations;
- successful results from our identified drilling locations;
- marketing of oil and natural gas;
- the integration and benefits of the Eagle Property Acquisition and the Anadarko Basin Acquisition or the effects of the acquisitions on our cash position and levels of indebtedness;
- infrastructure for salt water disposal;
- property acquisitions;
- costs of developing our properties and conducting other operations;
- general economic conditions;
- effectiveness of our risk management activities;
- environmental liabilities;
- counterparty credit risk;
- the outcome of pending and future litigation;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this quarterly report that are not historical.

All forward-looking statements speak only as of the date of this quarterly report. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this quarterly report are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements.

Table of Contents

Overview

We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-prone resources. Our operations originally focused on the Upper Gulf Coast Tertiary trend onshore in Louisiana, which we refer to as our Gulf Coast operating area. We began operations in the Mississippian Lime trend in Oklahoma and Kansas with the October 1, 2012 closing of our acquisition (Eagle Property Acquisition) of interests in producing oil and natural gas assets, unevaluated leasehold acreage in Oklahoma and Kansas and related hedging instruments from Eagle Energy Production, LLC (Eagle Energy). We began operations in the Anadarko Basin in Texas and Oklahoma with the May 31, 2013 closing of the Anadarko Basin Acquisition (as defined below). We refer to our Mississippian Lime and Anadarko Basin assets as our Mid-Continent operating area.

We were incorporated pursuant to the laws of the State of Delaware on October 25, 2011 to become a holding company for Midstates Petroleum Company LLC (Midstates Sub), a wholly-owned subsidiary of Midstates Petroleum Holdings LLC. Pursuant to the terms of a corporate reorganization that was completed immediately prior to the closing of our initial public offering on April 25, 2012, all of the interests in Midstates Petroleum Holdings LLC were exchanged for our newly issued common shares, and as a result, Midstates Petroleum Company LLC became our wholly-owned subsidiary and Midstates Petroleum Holdings LLC ceased to exist as a separate entity.

With the completion of our initial public offering, we became a publicly traded company. Our common stock is listed on the NYSE under the ticker symbol MPO. The terms the Company, we, us, our, and similar terms, when used in the present tense, prospectively or for historical periods since April 25, 2012 refer to us and our subsidiary, and for historical periods prior to April 25, 2012, refer to Midstates Petroleum Holdings LLC and its subsidiary, unless the context indicates otherwise.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. Our production volumes will decline as reserves are depleted unless we expend capital resources in successful development and exploration activities or acquire properties with existing production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity, constraints, inventory storage levels, basis differentials, and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

Anadarko Basin Acquisition

On April 3, 2013, we entered into a Purchase and Sale Agreement (the Agreement) with Panther Energy Company, LLC, Red Willow Mid-Continent, LLC and Linn Energy Holdings, LLC (collectively, the Sellers), pursuant to which we agreed to acquire producing properties as well as undeveloped acreage in the Anadarko Basin in Texas and Oklahoma (the Anadarko Basin Acquisition). Closing of this transaction occurred on May 31, 2013 for approximately $618 million in cash, subject to customary post-closing purchase price adjustments. The purchase price was funded with the $681 million in net proceeds (after initial purchasers discount and notes offering costs) from our sale of $700 million in aggregate principal amount of 9.25% senior unsecured notes due 2021 (the 2021 Senior Notes) maturing on June 1, 2021. See Liquidity and Capital Resources Significant Sources of Capital 2021 Senior Notes Offering for more information.

The oil and gas production and the financial results for the assets acquired in the Anadarko Basin Acquisition are included in our results beginning on May 31, 2013.

Operations Update

Mid-Continent Region

Our Mid-Continent assets were acquired on October 1, 2012 and May 31, 2013, and at September 30, 2013, consisted of approximately 101,710 net prospective acres in the Mississippian Lime/Hunton, with approximately 82,695 net acres in Woods and Alfalfa Counties of Oklahoma; approximately 5,665 net acres in Kansas and approximately 13,350 net acres in Lincoln County, Oklahoma, which produces primarily natural gas from the Hunton formation. In addition, we held 135,259 net acres in the Anadarko Basin, consisting of 89,161 acres in Texas and 46,098 acres in western Oklahoma. We currently intend to develop these oil and liquids rich properties using horizontal wells.

Mississippian Lime/Hunton

At September 30, 2013, our properties in the Mississippian Lime/Hunton area consisted of approximately 200 gross active producing wells, 85% of which we operate and in which we held an average working interest of 70%.

Table of Contents

For the three months ended September 30, 2013 and June 30, 2013, our average production from the Mississippian Lime/Hunton area was as follows:

	Three Months Ended September 30, 2013	Three Months Ended June 30, 2013	Increase (Decrease) in Production
Average production:			
Oil (Bbls)	5,081	3,404	49%
Natural gas liquids (Bbls)	2,959	1,776	67%
Natural gas (Mcf)	37,943	31,476	21%
Net boe/day	14,364	10,426	38%

Overall production increased by 38% versus the second quarter of 2013 primarily due to the results from increased drilling activity. Our NGL production increased by 67% when compared to the second quarter due to higher natural gas production volumes and increased volumes processed with the startup of a new third party owned and operated NGL plant in early June. The second quarter was adversely impacted by the bypass of a significant portion of our natural gas production due to processing plant constraints. Third quarter natural gas and NGL volumes were also positively impacted by 751 Boe/day due to the settlement of a volumetric imbalance related to production in prior periods.

The following table shows the total number of horizontal wells spud and brought into production in the Mississippian Lime/Hunton area of operation during the third quarter of 2013:

	Total Number of Horizontal Wells Spud (1)	Total Number of Horizontal Wells Brought into Production
Mississippian Lime/Hunton Area	22	29

(1) Of these 22 wells, 11 were producing, seven were awaiting completion and four were being drilled at quarter-end.

In the third quarter of 2013, we invested approximately $104.8 million; during the fourth quarter of 2013, we plan to invest approximately $85 million in the drilling of between 20 and 25 wells. Our plans are to continue development drilling targeting the Mississippian Lime interval in this area. We currently have a total of five operated drilling rigs targeting the Mississippian Lime interval in this area.

Anadarko Basin

At September 30, 2013, our properties in the Anadarko Basin area consisted of approximately 308 gross active producing wells, 79% of which we operate and in which we held an average working interest of approximately 67%.

For the three months ended September 30, 2013 and June 30, 2013, our average production from the Anadarko Basin area was as follows:

	Three Months Ended September 30, 2013	Three Months Ended June 30, 2013 (1)	Increase (Decrease) in Production
Average production:			
Oil (Bbls)	3,690	1,268	191%
Natural gas liquids (Bbls)	1,928	555	247%
Natural gas (Mcf)	16,716	5,075	229%
Net boe/day	8,404	2,668	215%

(1) One month only as we did not have production from these properties prior to the closing of the Anadarko Basin Acquisition on May 31, 2013.

Overall production increased by 215% versus the second quarter of 2013 primarily due to the inclusion of three months of activity from these assets during the third quarter compared to only one month during the second quarter, as the Anadarko Basin Acquisition did not close until May 31, 2013.

Table of Contents

The following table shows the total number of horizontal wells spud and brought into production in the Anadarko Basin area of operation during the third quarter of 2013:

	Total Number of Horizontal Wells Spud (1)	Total Number of Horizontal Wells Brought into Production
Anadarko Basin	16	10

(1) Of these 16 wells, six were producing, five were awaiting completion, and five were being drilled at quarter-end.

Our current development drilling is targeting the Cleveland, Marmaton, Cottage Grove and Tonkawa formations. In the third quarter of 2013, we invested approximately $31.7 million; for the fourth quarter of 2013, we plan to invest approximately $45 million in the drilling of between 18 and 20 wells. We currently have a total of five operated drilling rigs operating in the Anadarko Basin assets.

Gulf Coast Region

In our Gulf Coast region, our current acreage positions and evaluation efforts are concentrated in Louisiana in the Wilcox interval of the Upper Gulf Coast Tertiary trend. We have applied modern formation evaluation, drilling and completion techniques to the trend and our development operations in the Gulf Coast area are currently focused on drilling vertical and horizontal wells and commingling production from multi-stage hydraulically-fractured completions across stacked oil-producing intervals.

At September 30, 2013, our properties in the Gulf Coast region consisted of approximately 171 gross active producing wells, 96% of which we operate and in which we held an average working interest of 96%.

For the three months ended September 30, 2013 and June 30, 2013, our average production from the Gulf Coast area was as follows:

	Three Months Ended September 30, 2013	Three Months Ended June 30, 2013	Increase (Decrease) in Production
Average production:			
Oil (Bbls)	3,611	4,075	-11%
Natural gas liquids (Bbls)	973	1,089	-11%
Natural gas (Mcf)	6,677	8,257	-19%
Net boe/day	5,696	6,540	-13%

Overall, production from the Gulf Coast declined by 13% versus the second quarter of 2013, primarily due to base production decline and reduced development drilling.

During the third quarter of 2013, we invested approximately $23.7 million for exploration, development, facilities and lease and seismic acquisitions and completed one well in the Gulf Coast area.

As of September 30, 2013, we had accumulated approximately 111,050 net acres in the trend, including options to acquire an aggregate of approximately 51,055 targeted net acres. We currently do not have any drilling rigs operating in this area.

Gulf Coast Areas of Operation

Our Gulf Coast areas of operation are concentrated in oil and gas fields in Beauregard and Evangeline Parishes, Louisiana where we have 19,120 net

Table of Contents

acres under lease. The following table shows the number of gross horizontal wells spud and the number of horizontal wells brought into production in our Gulf Coast areas of operation during the third quarter of 2013:

	Total Number of Horizontal Wells Spud (1)	Total Number of Horizontal Wells Brought into Production
Pine Prairie		
South Bearhead Creek		1
North Coward s Gully	1	
Total Gulf Coast Area	1	1

(1) This well was brought online in early October 2013.

Expansion Areas within Gulf Coast

We negotiated seismic options to acquire 31,700 net acres in 2011 and an additional 24,000 net acres in 2012 in the trend and committed to shoot 3D seismic over the optioned acreage, which was delivered during the second quarter of 2013. We have begun evaluation of the results and we may acquire additional acreage within the 3D seismic shoot. At September 30, 2013, we held approximately 94,340 gross (91,930 net) acres in these expansion areas, through leases and options, and we are currently evaluating prospects on this acreage.

In the third quarter of 2013, we did not spud or complete any wells in our Gulf Coast expansion areas.

Capital Expenditures

During the three and nine months ended September 30, 2013, we incurred capital expenditures of $172.5 million and $454.7 million, respectively, including capitalized interest, which consisted primarily of (in thousands):

	For the Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2013
Drilling and completion activities	$ 142,167	$ 388,744
Acquisition of acreage and seismic data	11,225	27,594
Facilities and other	9,445	13,770
Capitalized interest	9,675	24,590
Total capital expenditures incurred	$ 172,512	$ 454,698

Excluding capitalized interest and amounts spent on corporate initiatives, the following was incurred in the various areas (in thousands):

	For the Three Months Ended September 30, 2013	For the Nine Months Ended September 30, 2013
Gulf Coast	$ 23,712	$ 142,028
Mid-Continent:		
Mississippian Lime	104,756	246,682
Anadarko	31,714	37,412
	$ 160,182	$ 426,122

Revolving Credit Facility

On September 26, 2013, the borrowing base was increased from $425 million to $500 million as part of the regularly scheduled semi-annual determination. Please see Liquidity and Capital Resources Significant Sources of Capital Reserve-based Credit Facility for more information.

Factors that Significantly Affect our Results

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

We generally hedge a portion of our expected future oil and gas production to reduce our exposure to fluctuations in commodity price. By removing a portion of commodity price volatility, we expect to reduce some of the variability in our cash flow from operations. See Item 3. Quantitative and Qualitative Disclosures About Market Risk Commodity Price Exposure beginning on page 39 for discussion of our hedging and hedge positions.

Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from any given well is expected to decline. As a result, oil and natural gas exploration and production companies deplete their asset base with each unit of oil or natural gas they produce. We attempt to overcome this natural production decline by developing additional reserves through our drilling operations, acquiring additional reserves and production and implementing secondary recovery techniques. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on the capital investments necessary to produce our reserves as well as to add to our reserves through drilling and acquisition. Our ability to make the necessary capital expenditures is dependent on cash flow from operations as well as our ability to obtain additional debt and equity financing. That ability can be limited by many factors, including the cost and terms of such capital and operational considerations.

The volumes of oil and natural gas that we produce are driven by several factors, including:

- success in the drilling of new wells, including exploratory wells, and the recompletion of existing wells;
- the amount of capital we invest in the leasing and development of our oil and natural gas properties;
- facility or equipment availability and unexpected downtime;
- delays imposed by or resulting from compliance with regulatory requirements; and
- the rate at which production volumes on our wells naturally decline.

Results of Operations

The following tables summarize our revenue, production and price data for the periods indicated.

Revenues

	For the Three Months Ended September 30, 2013		2012		For the Nine Months Ended September 30, 2013		2012	
	(in thousands)				(in thousands)			
REVENUES:								
Oil sales	$ 119,049	76%	$ 53,143	89%	$ 268,903	77%	$ 146,281	87%
Natural gas liquid sales	18,939	12%	4,134	7%	39,656	11%	14,307	8%
Natural gas sales	18,775	12%	2,257	4%	42,034	12%	8,086	5%
Total oil, natural gas, and natural gas liquids sales	156,763	100%	59,534	100%	350,593	100%	168,674	100%
Realized losses on commodity derivative contracts, net	(9,927)	22%	(4,160)	12%	(16,002)	37%	(15,840)	155%
Unrealized (losses) gains on commodity derivative contracts, net	(35,369)	78%	(29,566)	88%	(26,997)	63%	5,591	-55%
Losses on commodity derivative contracts net	(45,296)	100%	(33,726)	100%	(42,999)	100%	(10,249)	100%
Other	38		124		941		331	
Total revenues	$ 111,505		$ 25,932		$ 308,535		$ 158,756	

Production

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2013	2012	% Change	2013	2012	% Change
PRODUCTION DATA:						
Oil (MBbls)	1,139	509	124%	2,650	1,362	95%
Natural gas liquids (MBbls)	539	117	361%	1,128	342	230%
Natural gas (MMcf)	5,643	760	642%	12,522	3,129	300%
Oil equivalents (MBoe)	2,619	753	248%	5,864	2,225	164%
Oil (Boe/day)	12,382	5,537	124%	9,705	4,969	95%
Natural gas liquids (Boe/day)	5,860	1,267	361%	4,130	1,248	230%
Natural gas (Mcf/day)	61,336	8,261	642%	45,867	11,419	300%
Average daily production (Boe/d)	28,464	8,182	248%	21,480	8,120	164%

Prices

	For the Three Months Ended September 30,			For the Nine Months Ended September 30,		
	2013	2012	% Change	2013	2012	% Change
AVERAGE SALES PRICES:						
Oil, without realized derivatives (per Bbl)	$ 104.51	$ 104.32	0%	$ 101.49	$ 107.43	-6%
Oil, with realized derivatives (per Bbl)	$ 93.56	$ 96.15	-3%	$ 93.88	$ 95.80	-2%
Natural gas liquids, without realized derivatives (per Bbl)	$ 35.13	$ 35.46	-1%	$ 35.17	$ 41.84	-16%
Natural gas liquids, with realized derivatives (per Bbl)	$ 35.77	(a)		$ 36.36	(a)	
Natural gas, without realized derivatives (per Mcf)	$ 3.33	$ 2.97	12%	$ 3.36	$ 2.58	30%
Natural gas, with realized derivatives (per Mcf)	$ 3.72	(a)		$ 3.58	(a)	

(a) The Company did not have hedges in place on its NGL or natural gas production until October 1, 2012.

Three Months Ended September 30, 2013 as Compared to the Three Months Ended September 30, 2012

Oil, natural gas liquids and natural gas sales revenues

Our oil, natural gas and NGLs sales revenues increased by $97.3 million, or 164%, to $156.8 million during the three months ended September 30, 2013, as compared to $59.5 million during the three months ended September 30, 2012.

Our oil sales revenues increased by $65.9 million, or 124%, to $119.0 million during the three months ended September 30, 2013, as compared to $53.1 million for the three months ended September 30, 2012. Oil volumes sold increased 6,845 Boe/day, or 124%, to 12,382 Boe/day for the three months ended September 30, 2013 from 5,537 Boe/day for the three months ended September 30, 2012. This increase in oil volumes sold was attributable to the addition of 8,771 Boe/day of production volumes from our Mid-Continent area, which consisted of properties acquired on October 1, 2012 in the Eagle Property Acquisition and May 31, 2013 in the Anadarko Basin Acquisition, partially offset by a decrease in volumes from our Gulf Coast region of 1,926 Boe/day primarily due to base production decline and reduced development drilling activity during the 2013 period. During the three months ended September 30, 2012, all of our production was from our Gulf Coast region. Average oil sales prices, without realized derivatives, decreased by $0.19 per barrel to $104.51 per barrel during the three months ended September 30, 2013 as compared to $104.32 per barrel for the three months ended September 30, 2012 primarily due to lower oil prices received for our Mid-Continent production, which is priced off WTI as opposed to LLS for our Gulf Coast production.

Our NGL sales revenues increased by $14.8 million, or 361%, to $18.9 million during the three months ended September 30, 2013, as compared to $4.1 million for the three months ended September 30, 2012. NGL volumes sold increased 4,593 Boe/day, or 361%, to 5,860 Boe/day for the three months ended September 30, 2013 from 1,267 Boe/day for the three months ended September 30, 2012. This increase in NGL volumes sold was attributable to the addition of 4,887 Boe/day of production volumes from our Mid-Continent area, which consists of properties acquired on October 1, 2012 and May 31, 2013 (as described above), partially offset by a 294 Boe/day decrease in production from our Gulf Coast area. NGL production for the three months ended September 30, 2013 was also favorably impacted by the settlement during the period of a volumetric production imbalance related to prior periods, as discussed above. Average NGL sales prices, without realized derivatives, decreased by $2.19 per barrel, or 1%, to $35.13 per barrel during the three months ended September 30, 2013 as compared to $35.46 per barrel for the corresponding period in 2012.

Our natural gas sales revenues increased by $16.5 million, or 717%, to $18.8 million during the three months ended September 30, 2013, as compared to $2.3 million for the three months ended September 30, 2012. Natural gas volumes sold increased 53,075 Mcf/day or 642%, to 61,336 Mcf/day for the three months ended September 30, 2013 from 8,261 Mcf/day for the three months ended September 30, 2012. This increase in natural gas volumes sold was attributable to the addition of 54,659 Mcf/day of production volumes from our Mid-Continent area, which consisted of properties acquired on October 1, 2012 and May 31, 2013 (as described above), partially offset by a decrease in production of 1,584 Mcf/day from our Gulf Coast area. Natural gas production was also favorably impacted by the settlement during the period of a volumetric production imbalance related to prior periods, as discussed above. Average natural gas sales prices, without realized derivatives, increased by $0.36 per Mcf, or 12%, to $3.33 per Mcf during the three months ended September 30, 2013 as compared to $2.97 per Mcf for the three months ended September 30, 2012.

Gains/losses on commodity derivative contracts - net

Our mark-to-market (MTM) derivative positions moved from an unrealized loss of $29.6 million for the three months ended September 30, 2012 to an unrealized loss of $35.4 million for the three months ended September 30, 2013. The MTM change resulted from higher average amounts of volumes hedged and unfavorable market price movements during the period versus the average price at which our production is hedged. We entered into additional derivative contracts during 2013 and, with the closing of the Eagle Property Acquisition on October 1, 2012, assumed the related oil, natural gas and NGL hedging instruments associated with those acquired properties. The NYMEX WTI closing price on September 28, 2012 (the last day of trading for the period) was $92.19 per barrel compared to a closing price of $102.33 per barrel on September 30, 2013 (the last day of trading for the period).

The realized loss on derivatives for the three months ended September 30, 2013 was $9.9 million, compared to a realized loss of $4.2 million for the three months ended September 30, 2012. As discussed above, with the closing of the Eagle Property Acquisition, we assumed the related NGL and natural gas hedging instruments. Therefore, our realized gains/losses for the three months ended September 30, 2013 included realized gains/losses on these commodities in addition to oil. Prior to assuming these derivatives as part of this acquisition, we only hedged oil. The following table presents realized gain (loss) by type of commodity contract:

	Three Months Ended September 30, 2013			
	Realized Gain (Loss) (in thousands)		Average Sales Price	
Oil commodity contracts	$	(12,474)	$	93.56
Natural gas liquids commodity contracts		347	$	35.77
Natural gas commodity contracts		2,200	$	3.72
	$	(9,927)		

<u>Nine Months Ended September 30, 2013 as Compared to the Nine Months Ended September 30, 2012</u>

Oil, natural gas liquids and natural gas sales revenues

Our oil, natural gas and NGLs sales revenues increased by $181.9 million, or 108%, to $350.6 million during the nine months ended September 30, 2013, as compared to $168.7 million during the nine months ended September 30, 2012.

Our oil sales revenues increased by $122.6 million, or 84%, to $268.9 million during the nine months ended September 30, 2013, as compared to $146.3 million for the nine months ended September 30, 2012. Oil volumes sold increased 4,736 Boe/day, or 95%, to 9,705 Boe/day for the nine months ended September 30, 2013 from 4,969 Boe/day for the nine months ended September 30, 2012. This increase in oil volumes sold was attributable to the addition of 5,641 Boe/day of production volumes from our Mid-Continent area, which was acquired on October 1, 2012 and May 31, 2013, as described above, partially offset by a decrease of 905 Boe/day from our Gulf Coast area attributable to base production decline and less development drilling during the 2013 period. During the nine months ended September 30, 2012, all of our production was from our Gulf Coast region. Average oil sales prices, without realized derivatives, decreased by $5.94 per barrel, or 6%, to $101.49 per barrel during the nine months ended September 30, 2013 as compared to $107.43 per barrel for the nine months ended September 30, 2012 primarily due to lower oil prices received for our Mid-Continent production, which is priced off WTI as opposed to LLS for our Gulf Coast production.

Our NGL sales revenues increased by $25.4 million, or 178%, to $39.7 million during the nine months ended September 30, 2013, as compared to $14.3 million for the nine months ended September 30, 2012. NGL volumes sold increased 2,882 Boe/day, or 230%, to 4,130 Boe/day for the nine months ended September 30, 2013 from 1,248 Boe/day for the nine months ended September 30, 2012. This increase in NGL volumes sold was attributable to the addition of 3,117 Boe/day of production volumes from our Mid-Continent area, which consisted of properties acquired on October 1, 2012 and May 31, 2013 (as described above) partially offset by a 235 Boe/day decrease in production from our Gulf Coast area. Average NGL sales prices, without realized derivatives, decreased by $6.67 per barrel, or 16%, to $35.17 per barrel during the nine months ended September 30, 2013 as compared to $41.84 per barrel for the corresponding period in 2012.

Our natural gas sales revenues increased by $33.9 million, or 419%, to $42.0 million during the nine months ended September 30, 2013, as compared to $8.1 million for the nine months ended September 30, 2012. Natural gas volumes sold increased 34,448 Mcf/day, or 300%, to 45,867 Mcf/day for the nine months ended September 30, 2013 from 11,419 Mcf/day for the nine months ended September 30, 2012. This increase in natural gas volumes sold was attributable to the addition of 38,399 Mcf/day of production volumes from our Mid-Continent area, which consisted of properties acquired on October 1, 2012 and May 31, 2013 (as described above), partially offset by a decrease in production of 3,950 Mcf/day from our Gulf Coast area. Average natural gas sales prices, without realized derivatives, increased by $0.78 per Mcf, or 30%, to $3.36 per Mcf during the nine months ended September 30, 2013 as compared to $2.58 per Mcf for the nine months ended September 30, 2012.

Gains/losses on commodity derivative contracts - net

Our mark-to-market (MTM) derivative positions moved from an unrealized gain of $5.6 million for the nine months ended September 30, 2012 to an unrealized loss of $27.0 million for the nine months ended September 30, 2013. The MTM change resulted from higher average hedge volumes and unfavorable market price movements during the 2013 period versus the average price at which our production is hedged. We entered into additional derivative contracts during 2013 and, assumed with the closing of the Eagle Property Acquisition on October 1, 2012, the related oil, NGL and natural gas hedging instruments associated with those acquired properties. The NYMEX WTI closing price on September 28, 2012 (the last day of trading for the period) was $92.19 per barrel compared to a closing price of $102.33 per barrel on September 30, 2013 (the last day of trading for the period).

The realized loss on derivatives for the nine months ended September 30, 2013 was $16.0 million, compared to a realized loss of $15.8 million for the nine months ended September 30, 2012. As discussed above, with the closing of the Eagle Property Acquisition, we assumed the related oil, NGL and natural gas hedging instruments. Therefore, our realized gains/losses for the nine months ended September 30, 2013 included realized gains/losses on these commodities in addition to oil. Prior to assuming these derivatives as part of this acquisition, we only hedged oil. The following table presents realized gain (loss) by type of commodity contract:

	Nine Months Ended September 30, 2013			
	Realized Gain (Loss) (in thousands)		Average Sales Price	
Oil commodity contracts	$	(20,157)	$	93.88
Natural gas liquids commodity contracts		1,341	$	36.36
Natural gas commodity contracts		2,814	$	3.58
	$	(16,002)		

Operating Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and a per Boe basis. Depending on the relevance, our discussion may reference expenses on an absolute dollar basis, a per Boe basis, or both.

	Three Months Ended September 30,								Nine Months Ended September 30,							
	2013		2012		2013		2012		2013		2012		2013		2012	
	(in thousands)				(per Boe)				(in thousands)				(per Boe)			
EXPENSES:																
Lease operating and workover	$	21,784	$	6,569	$	8.32	$	8.72	$	53,230	$	18,957	$	9.08	$	8.52
Gathering and transportation		2,583			$	0.99	$			2,583			$	0.44	$	
Severance and other taxes		8,080		6,450	$	3.09	$	8.57		20,614		18,098	$	3.52	$	8.13
Asset retirement accretion		421		165	$	0.16	$	0.22		988		463	$	0.17	$	0.21
Depreciation, depletion, and amortization		74,789		30,692	$	28.56	$	40.76		169,595		86,601	$	28.92	$	38.92
General and administrative		13,911		7,948	$	5.31	$	10.56		40,209		18,966	$	6.86	$	8.52
Acquisition and transaction costs		194		2,675	$	0.07	$	3.55		11,686		2,675	$	1.99	$	1.20
Other		614			$	0.23	$			614			$	0.10	$	
Total expenses	$	122,376	$	54,499	$	46.73	$	72.38	$	299,519	$	145,760	$	51.08	$	65.50

<u>Three Months Ended September 30, 2013 as Compared to the Three Months Ended September 30, 2012</u>

Lease operating and workover expenses

Lease operating and workover expenses increased $15.2 million, or 230%, to $21.8 million for the three months ended September 30, 2013 compared to $6.6 million for the three months ended September 30, 2012. Lease operating expenses increased $14.2 million, or 245%, to $20.0 million, for the three months ended September 30, 2013 as compared to $5.8 million for the related period in 2012. Of this increase, approximately $13.3 million relates to the Mid-Continent area, which was acquired on October 1, 2012 and May 31, 2013 (as described above). The remaining $0.9 million increase is related to costs associated with an increase in Gulf Coast producing well count, which increased by approximately 30 wells period-over-period. Workover expenses increased $1.0 million, or 125%, to $1.8 million for the three months ended September 30, 2013 compared to $0.8 million for the three months ended September 30, 2012. Of this increase, approximately $0.5 million relates to the Mid-Continent area and approximately $0.5 million relates to Gulf Coast workover costs. Lease operating and workover expenses decreased to $8.32 per Boe for the three months ended September 30, 2013, a decrease of $0.40, or 5%, over the corresponding period in 2012. This decrease was primarily attributable to increased production during the 2013 period, the realization of some of the expense benefits of investments made in prior periods to reduce salt water disposal costs in the Gulf Coast and Mississippian Lime area, and the migration from diesel fired generators to natural gas generators in the Mississippian Lime area during 2013.

Gathering and transportation

Gathering and transportation expenses were $2.6 million for the three months ended September 30, 2013. These expenses are attributable to the commencement of an amended gas transportation, gathering and processing contract during the third quarter of 2013 in the Mississippian Lime that included a $0.36 Mmbtu gathering fee based upon wellhead volumes.

Severance and other taxes

	Three Months Ended September 30, 2013		2012
Total oil, natural gas, and natural gas liquids sales	$ 156,763		$ 59,534
Severance taxes	6,273		5,648
Advalorem	1,807		802
Severance and other taxes	$ 8,080		$ 6,450
Severance taxes as a percentage of sales	4.0%		9.5%
Severance and other taxes as a percentage of sales	5.2%		10.8%

Severance and other taxes increased $1.6 million, or 25%, to $8.1 million for the three months ended September 30, 2013 compared to $6.5 million for the three months ended September 30, 2012. Severance taxes increased $0.6 million, or 11%, to $6.3 million for the three months ended September 30, 2013, as compared to $5.7 million for the three months ended September 30, 2012. This increase was attributable to higher oil, natural gas liquids and natural gas sales revenues. Ad valorem taxes increased $1.0 million, or 125%, to $1.8 million for the three months ended September 30, 2013, as compared to $0.8 million for the three months ended September 30, 2012, corresponding to a related increase in producing wells due to the acquisitions discussed above and increased development drilling. Severance taxes as a percentage of sales changed from 9.5% for the three months ended September 30, 2012 to 4.0% due to lower effective severance tax rates in our Mid-Continent region and lower production period-over-period in the relatively higher tax Gulf Coast region.

Depreciation, depletion and amortization (DD&A)

DD&A expense increased $44.1 million, or 144%, to $74.8 million for the three months ended September 30, 2013 compared to $30.7 million for the three months ended September 30, 2012. The DD&A rate for the 2013 period was $28.56 per Boe compared to $40.76 per Boe for the 2012 period. The decrease in DD&A rate was primarily due to the addition of reserves in the Mid-Continent region on October 1, 2012 with the Eagle Property Acquisition and on May 31, 2013 with the Anadarko Basin Acquisition as well as overall growth in proved reserves. Overall DD&A expense increased due to higher production, partially offset by the lower DD&A rate discussed above.

General and administrative (G&A)

Our G&A expenses increased by $6.0 million, or 76%, to $13.9 million for the three months ended September 30, 2013, compared to $7.9 million for the three months ended September 30, 2012. The increase is primarily attributable to approximately $3.2 million in additional employee related expenses (including salary, share-based compensation expense and bonus) resulting from an increase in headcount from 88 full time employees at September 30, 2012 to 175 full time employees at September 30, 2013 and payments under the respective Transition Services Agreements to Eagle Energy Production, LLC and Panther Energy Company, LLC. The Transition Services Agreement with Eagle expired on September 30, 2013 and the Transition Services Agreement with Panther will expire on November 30, 2013.

Acquisition and transaction costs

Our acquisition and transaction costs were $0.2 million for the three months ended September 30, 2013, compared to $2.7 million for the three months ended September 30, 2012. For the 2013 period, these costs represent our expenses related to the Anadarko Basin Acquisition and are primarily attributable to due diligence costs and legal fees. For the 2012 period, these costs represent our expenses related to the Eagle Property Acquisition and are primarily attributable to due diligence costs and legal fees. These costs are required to be expensed under US GAAP.

Other

Other operating expenses for the three months ended September 30, 2013 were $0.6 million and represent the loss on disposal of field equipment inventory deemed no longer essential to operations.

<u>Nine Months Ended September 30, 2013 as Compared to the Nine Months Ended September 30, 2012</u>

Lease operating and workover expenses

Lease operating and workover expenses increased $34.2 million, or 180%, to $53.2 million for the nine months ended September 30, 2013 compared to $19.0 million for the nine months ended September 30, 2012. Lease operating expenses increased $29.7 million, or 178%, to $46.3 million, for the nine months ended September 30, 2013 as compared to $16.6 million for the related period in 2012. Of this increase, approximately $25.1 million relates to the Mid-Continent area, which was acquired on October 1, 2012 and May 31, 2013 (as described above). The remaining $4.6 million increase is related to costs associated with an increase in Gulf Coast producing well count, which increased by approximately 30 wells period-over-period.

Table of Contents

Workover expenses increased $4.5 million, or 196%, to $6.9 million for the nine months ended September 30, 2013 compared to $2.4 million for the nine months ended September 30, 2012. Of this increase, approximately $4.4 million relates to the Mid-Continent area and approximately $0.1 million to the Gulf Coast. Lease operating and workover expenses increased to $9.08 per Boe for the nine months ended September 30, 2013, an increase of $0.56, or 7%, over the corresponding period in 2012. This increase was primarily attributable to increased lease operating costs incurred in the Mississippian Lime area earlier in the year attributable to adverse winter weather that resulted in power failures and the temporary shut-in of production, as well as higher salt water disposal costs in the Gulf Coast area. During the third quarter, the Company began to realize some of the expense benefits of investments made to improve salt water disposal and power generation as discussed above.

Gathering and transportation

Gathering and transportation expenses were $2.6 million for the nine months ended September 30, 2013. These expenses are attributable to the commencement of an amended gas transportation, gathering and processing contract during the third quarter of 2013 in the Mississippian Lime area that included a $0.36 Mmbtu gathering fee based upon wellhead volumes.

Severance and other taxes

	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Total oil, natural gas, and natural gas liquids sales	$ 350,593	$ 168,674
Severance taxes	16,487	15,600
Ad valorem	4,127	2,498
Severance and other taxes	$ 20,614	$ 18,098
Severance taxes as a percentage of sales	4.7%	9.2%
Severance and other taxes as a percentage of sales	5.9%	10.7%

Severance and other taxes increased $2.5 million, or 14%, to $20.6 million for the nine months ended September 30, 2013 compared to $18.1 million for the nine months ended September 30, 2012. Severance taxes increased $0.9 million, or 6%, to $16.5 million for the nine months ended September 30, 2013, as compared to $15.6 million for the nine months ended September 30, 2012. This increase was attributable to the higher oil, natural gas liquids and natural gas sales revenues during the nine months of 2013. Ad valorem taxes increased $1.6 million, or 65%, to $4.1 million for the nine months ended September 30, 2013, as compared to $2.5 million for the nine months ended September 30, 2012, corresponding to a related increase in producing wells due to the acquisitions discussed above and increased development drilling. Severance taxes as a percentage of sales changed from 9.2% for the nine months ended September 30, 2012 to 4.7% due to lower effective severance tax rates in our Mid-Continent region and lower production period-over-period in the relatively higher tax Gulf Coast region.

Depreciation, depletion and amortization (DD&A)

DD&A expense increased $83.0 million, or 96%, to $169.6 million for the nine months ended September 30, 2013 compared to $86.6 million for the nine months ended September 30, 2012. The DD&A rate for the 2013 period was $28.92 per Boe compared to $38.92 per Boe for the 2012 period. The decrease in DD&A rate was primarily due to the addition of reserves in the Mid-Continent region on October 1, 2012 with the Eagle Property Acquisition and on May 31, 2013 with the Anadarko Basin Acquisition as well as overall growth in proved reserves.

General and administrative (G&A)

Our G&A expenses increased by $21.2 million, or 112%, to $40.2 million for the nine months ended September 30, 2013, compared to $19.0 million for the nine months ended September 30, 2012. The increase is primarily attributable to $2.0 million in professional fees, $1.3 million in other taxes, $0.5 million in rent, approximately $11.3 million in additional employee related expenses (including salary, share-based compensation expense and bonus) resulting from an increase in headcount from 88 full time employees at September 30, 2012 to 175 full time employees at September 30, 2013, and payments under the respective Transition Services Agreements to Eagle Energy Production, LLC and Panther Energy Company, LLC. The Transition Services Agreement with Eagle expired on September 30, 2013 and the Transition Services Agreement with Panther will expire on November 30, 2013.

Acquisition and transaction costs

Our acquisition and transaction costs were $11.7 million for the nine months ended September 30, 2013, compared to $2.7 million in acquisition and transaction costs for the nine months ended September 30, 2012. For the 2013 period, these costs represent our expenses related to the Anadarko Basin Acquisition and are primarily attributable to bridge financing fees, due diligence costs and legal fees. For the 2012 period, these costs represent our expenses related to the Eagle Property Acquisition and are primarily attributable to due diligence costs and legal fees. These costs are required to be expensed under US GAAP.

Table of Contents

Other

Other operating expenses for the nine months ended September 30, 2013 were $0.6 million and represent the loss on disposal of field equipment inventory deemed no longer essential to operations.

Other Income (Expenses)

	For the Three Months Ended September 30, 2013	For the Three Months Ended September 30, 2012	For the Nine Months Ended September 30, 2013	For the Nine Months Ended September 30, 2012
	(in thousands)			
OTHER INCOME (EXPENSE)				
Interest income	$ 7	$ 80	$ 17	$ 229
Interest expense	(35,625)	(1,734)	(78,028)	(6,798)
Capitalized Interest	9,675	826	24,590	3,211
Interest expense net of amounts capitalized	(25,950)	(908)	(53,438)	(3,587)
Total other income (expense)	$ (25,943)	$ (828)	$ (53,421)	$ (3,358)

Three Months Ended September 30, 2013 as Compared to the Three Months Ended September 30, 2012

Interest expense

Interest expense for the three months ended September 30, 2013 and 2012 was $35.6 million and $1.7 million, respectively. The increase in interest expense was primarily due to the issuance of the 2021 Senior Notes (as discussed below) and the 2020 Senior Notes (as discussed below). Our average outstanding balance under the revolver was $271.1 million during the three months ended September 30, 2013, compared to $185.3 million for the three months ended September 30, 2012, and related to $1.7 million of the total interest expense of $35.6 million for 2013. Of the remainder, $16.1 million was interest incurred under the 2020 Senior Notes, $15.9 million was interest incurred under the 2021 Senior Notes and $1.9 million represented amortization of deferred financing costs. Of the total interest expense, $9.7 million and $0.8 million was capitalized, resulting in $25.9 million and $0.9 million in interest expense, net of capitalized interest, for the three months ended September 30, 2013 and 2012, respectively.

Nine Months Ended September 30, 2013 as Compared to the Nine Months Ended September 30, 2012

Interest expense

Interest expense for the nine months ended September 30, 2013 and 2012 was $78.0 million and $6.8 million, respectively. The increase in interest expense was primarily due to the issuance of the 2021 Senior Notes (as discussed below) and the 2020 Senior Notes (as discussed below). Our average outstanding balance under the revolver was $210.5 million during the nine months ended September 30, 2013, compared to $194.6 million for the nine months ended September 30, 2012, and related to $3.9 million of the total interest expense of $78.0 million for 2013. Of the remainder, $48.3 million was interest incurred under the 2020 Senior Notes, $21.6 million was interest incurred under the 2021 Senior Notes and $4.2 million represented amortization of deferred financing costs. Of the total interest expense, $24.6 million and $3.2 million was capitalized, resulting in $53.4 million and $3.6 million in interest expense, net of capitalized interest, for the nine months ended September 30, 2013 and 2012, respectively.

Provision for Income Taxes

Three Months Ended September 30, 2013 as Compared to the Three Months Ended September 30, 2012

Our income tax benefit was $13.2 million and $11.6 million for the three months ended September 30, 2013 and 2012, respectively. The resulting income tax benefit for the three months ended September 30, 2013 represents an effective tax rate (including state income taxes) of approximately 35.9%.

Nine Months Ended September 30, 2013 as Compared to the Nine Months Ended September 30, 2012

Our income tax benefit was $16.2 million for the nine months ended September 30, 2013 and was an expense of $157.3 million for the nine months ended September 30, 2012. The resulting income tax expense for the nine months ended September 30, 2013 represents an effective tax rate (including state income taxes) of approximately 36.5%. The 2012 period includes a non-cash deferred tax change of $149.5 million related to our corporate reorganization in connection with our April 2012 initial public offering.

Liquidity and Capital Resources

At September 30, 2013, our liquidity was $218.6 million consisting of $193.7 million of available borrowing capacity under our revolving credit facility and $25.0 million of cash and cash equivalents.

Table of Contents

We plan to finance our capital expenditures for the remainder of 2013 and 2014 with the cash flow from operations and borrowings under our reserve-based credit facility. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital. In the event we are unable to access additional funding through debt or equity markets, through growth in our reserve-based credit facility, or by securing other external sources of funding, we could be required to reduce our future capital program or pursue other alternatives to develop our assets. If we reduce our future planned exploration and development expenditures, we believe that those steps, together with our available cash, anticipated future cash flows from operations and borrowings under our revolving credit facility will be sufficient to meet our reduced expenditures and operating needs beyond the third quarter of 2014.

We may from time to time seek to retire, purchase or exchange our outstanding debt in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

Significant Sources of Capital

Reserve-based Credit Facility

As of September 30, 2013, our credit facility consisted of a $750 million senior revolving credit facility (the Credit Facility) with a borrowing base of $500 million, as recently redetermined on September 26, 2013, when the borrowing base was increased from $425 million.

The Credit Facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of our oil and natural gas properties and currently bear interest at LIBOR plus an applicable margin, depending upon our borrowing base utilization, between 1.75% and 2.75% per annum. At September 30, 2013 and December 31, 2012, the weighted average interest rate was 2.5% and 2.9%, respectively.

In addition to interest expense, the Credit Facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of either 0.375% or 0.50% per annum based on the average daily amount by which the borrowing base exceeds the outstanding borrowings during each quarter.

The borrowing base under the Credit Facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by us or the administrative agent, acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations. The next scheduled borrowing base redetermination date is April 1, 2014.

Under the terms of the Credit Facility, we are required to repay the amount by which the principal balance of our outstanding loans and letter of credit obligations exceed our redetermined borrowing base. We are permitted to make such repayment in six equal successive monthly payments commencing 30 days following the administrative agent s notice regarding such borrowing base reduction.

On September 26, 2013, we entered into the Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement among the Company, as parent, Midstates Sub, as borrower, SunTrust Bank, N.A., as administrative agent, and the other lenders and parties party thereto (the Fourth Amendment).

The Fourth Amendment amended the Credit Facility to provide that our ratio of total net indebtedness to EBITDA for the trailing four fiscal quarter period ending on the last day of such fiscal quarter cannot exceed (i) 4.75:1.0, for the fiscal quarters ending September 30, 2013, December 31, 2013 and March 31, 2014, (ii) 4.50:1.0, for the fiscal quarters ending June 30, 2014, (iii) 4.25:1.0, for the fiscal quarters ending September 30, 2014 and December 31, 2014, and (iv) 4.00:1.0, for the fiscal quarter ending March 31, 2015 and each fiscal quarter thereafter. We also agreed to pay a one-time fee of 0.50% to each lender on the portion of their commitment to the borrowing base under the Fourth Amendment in excess of their commitment prior to the Fourth Amendment, and a one-time fee of 0.10% to each lender on the lesser of such lenders commitment immediately prior to, or after giving effect to, the Fourth Amendment.

The Credit Facility contains financial covenants, in addition to the maximum ratio of debt to EBITDA discussed above, which, among other things, set a minimum current ratio (as defined therein) of not less than 1.0 to 1.0 and various other standard affirmative and negative covenants including, but not limited to, restrictions on the our ability to make any dividends, distributions or redemptions.

As of September 30, 2013, we were in compliance with the minimum current ratio and the ratio of debt to EBITDA covenants as set forth in the Credit Facility. Our current ratio at September 30, 2013 was 1.5 to 1.0. At September 30, 2013, our ratio of debt to EBITDA was 4.4 to 1.0.

Table of Contents

2020 Senior Notes Offering

On October 1, 2012, we issued $600 million in aggregate principal amount of 10.75% senior notes due 2020 (the 2020 Outstanding Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. On October 29, 2013, substantially all of the 2020 Outstanding Notes were exchanged for an equal principal amount of registered 10.75% senior subordinated notes due 2020 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the 2020 Exchange Notes). The 2020 Exchange Notes are identical to the 2020 Outstanding Notes except that the 2020 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-Q, the term 2020 Senior Notes refer to both the 2020 Outstanding Notes and the 2020 Exchange Notes. The proceeds from the offering of $582 million (net of the initial purchasers discount and related offering expenses) were used to fund the cash portion of, and expenses related to, the Eagle Property Acquisition, to pay the expenses related to the amendments to the revolving credit facility, to repay $182.9 million in outstanding borrowings under our Credit Facility, and for general corporate purposes.

We co-issued the 2020 Senior Notes on a joint and several basis with Midstates Sub. We do not have any operations or independent assets other than our 100% ownership interest in Midstates Sub and we do not own any other subsidiaries. The Notes indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to us or limit our ability to advance loans to Midstates Sub.

At any time prior to October 1, 2015, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes with the net proceeds of a public or private equity offering at a redemption price of 110.75% of the principal amount of the 2020 Senior Notes, plus any accrued and unpaid interest up to the redemption date. In addition, at any time before October 1, 2016, we may redeem all or a part of the 2020 Senior Notes at a redemption price equal to 100% of the principal amount of the 2020 Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, up to, the redemption date.

On or after October 1, 2016, we may redeem all or a part of the 2020 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the Indenture plus accrued and unpaid interest and Additional Interest (as defined in the Indenture), if any, on the 2020 Senior Notes redeemed, up to, the redemption date. The Indenture contains covenants that, among other things, restrict our ability to: (i) incur additional indebtedness, guarantee indebtedness or issue certain preferred shares; (ii) make loans, investments and other restricted payments; (iii) pay dividends on or make other distributions in respect of, or repurchase or redeem, capital stock; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with our affiliates; (vii) consolidate, merge or sell substantially all of our assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business we conduct and (x) enter into agreements restricting the ability of our subsidiaries to pay dividends.

Upon the occurrence of certain change of control events, as defined in the Indenture, each holder of the 2020 Senior Notes will have the right to require that we repurchase all or a portion of such holder s 2020 Senior Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase. In connection with the private placement of the 2020 Senior Notes, on October 1, 2012, we entered into a registration rights agreement (the 2020 Notes Registration Rights Agreement) obligating us to use reasonable best efforts to file an exchange registration statement with the SEC so that holders of the 2020 Senior Notes can offer to exchange the 2020 Senior Notes offering for registered notes having substantially the same terms as the 2020 Senior Notes and evidencing the same indebtedness as the 2020 Senior Notes.

2021 Senior Notes Offering

On May 31, 2013, we issued $700 million in aggregate principal amount of 9.25% senior notes due 2021 (the 2021 Outstanding Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. On October 29, 2013, all of the 2021 Outstanding Notes were exchanged for an equal principal amount of registered 9.25% senior subordinated notes due 2021 pursuant to an effective registration statement on Form S-4 filed on August 30, 2013 under the Securities Act (the 2021 Exchange Notes). The 2021 Exchange Notes are identical to the 2021 Outstanding Notes except that the 2021 Exchange Notes are registered under the Securities Act and do not have restrictions on transfer, registration rights or provisions for additional interest. As used in this Form 10-Q, the term 2021 Senior Notes refer to both the 2021 Outstanding Notes and the 2021 Exchange Notes. The proceeds from the offering of $681 million (net of the initial purchasers discount and related offering expenses) were used to fund the Anadarko Basin Acquisition (and the related expenses), to pay expenses related to amending our Credit Facility, to repay $34.3 million in outstanding borrowings under our Credit Facility, and for general corporate purposes.

The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes.

We co-issued the 2021 Senior Notes on a joint and several basis with Midstates Sub. The 2021 Senior Notes indenture does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to us or limit our ability to advance loans to Midstates Sub.

On or prior to May 31, 2014, we may redeem up to $100.0 million of aggregate principal amount of the 2021 Senior Notes with the net cash proceeds from any Equity Offerings (as such term is defined in the 2021 Senior Notes Indenture) at a redemption price equal to 103% of the principal amount plus accrued and unpaid interest.

Prior to June 1, 2016, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes (less the amount of 2021 Senior Notes redeemed pursuant to the preceding paragraph) with the net proceeds of any Equity Offerings at a redemption price of

Table of Contents

109.25% of the principal amount of the 2021 Senior Notes redeemed, plus any accrued and unpaid interest up to the redemption date. In addition, at any time before June 1, 2016, we may redeem all or a part of the 2021 Senior Notes at a redemption price equal to 100% of the principal amount of 2021 Senior Notes redeemed plus the Applicable Premium (as defined in the Indenture) at the redemption date, plus any accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, up to, the redemption date. On or after October 1, 2016, we may redeem all or a part of the 2021 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2021 Senior Notes Indenture plus accrued and unpaid interest and Additional Interest (as defined in the 2021 Senior Notes Indenture), if any, on the 2021 Senior Notes redeemed, up to, the redemption date.

The terms of the covenants and change in control provisions in the 2021 Senior Notes Indenture are substantially identical to those of the 2020 Senior Notes discussed above. Additionally the Company entered into a registration rights agreement (the 2021 Registration Rights Agreement) with provisions substantially identical to that of the 2020 Notes Registration Rights Agreement.

Series A Preferred Stock

On October 1, 2012 we issued 325,000 shares of our Series A Preferred Stock as part of the purchase price paid to complete the Eagle Property Acquisition. The shares of Series A Preferred Stock have an initial liquidation value of $1,000 per share and are convertible into shares of our common stock on or after October 1, 2013. At such time, the Series A Preferred Stock may be converted, in whole but not in part, at the option of the holders of a majority of the outstanding shares of Series A Preferred Stock, into a number of shares of our common stock calculated by dividing the then-current liquidation preference by the conversion price of $13.50 per share. If not previously converted, the Series A Preferred Stock will be subject to mandatory conversion into shares of our common stock on September 30, 2015 at a conversion price based upon the volume weighted average price of our common stock during the 15 trading days immediately prior to the mandatory conversion date, but in no instance will the price be greater than $13.50 per share or less than $11.00 per share. Dividends on the Series A Preferred Stock will accrue at a rate of 8.0% per annum, payable semiannually, at our sole option, in cash or through an increase in the liquidation preference. The issuance of the Series A Preferred Stock to Eagle pursuant to the Eagle Purchase Agreement was approved by our stockholders holding a majority of the outstanding shares of our common stock.

Cash Flows from Operating, Investing and Financing Activities

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented. For information regarding the individual components of our cash flow amounts, please refer to the Unaudited Condensed Consolidated Statements of Cash Flows included under Item 1 of this quarterly report.

Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of these commodities. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see Item 3. Quantitative and Qualitative Disclosures About Market Risk beginning on page 39.

The following information highlights the significant period-to-period variances in our cash flow amounts (table in thousands):

	For the Nine Months Ended September 30,	
	2013	2012
Net cash provided by operating activities	$ 179,941	$ 94,680
Net cash used in investing activities	(1,059,269)	(284,875)
Net cash provided by financing activities	885,403	187,525
Net change in cash	$ 6,075	$ (2,670)

Cash flows provided by operating activities

Net cash provided by operating activities was $179.9 million and $94.7 million for the nine months ended September 30, 2013 and 2012, respectively. The increase in net cash provided by operating activities was primarily the result of an increase in oil and natural gas revenues due to the acquisitions discussed above and organic production growth and favorable working capital changes, partially offset by lower realized oil and NGL prices.

Cash flows used in investing activities

Net cash used in investing activities was $1.1 billion and $285 million during the nine months ended September 30, 2013 and 2012, respectively. The increase in our investing activities during the 2013 period is primarily attributable to the Anadarko Basin Acquisition on May 31, 2013 and the continued expansion of our drilling program.

Table of Contents

Cash flows provided by financing activities

Net cash provided by financing activities was $885.4 million and $187.5 million for the nine months ended September 30, 2013 and 2012, respectively. During the nine months ended September 30 2013, cash was sourced through the revolving credit facility, with draws of $246.5 million during the period and repayments of $34.3 million, and $700 million from the 2021 Senior Notes placed in May 2013. During the nine months ended September 30, 2012, cash sourced from financing activities was primarily from our initial public offering of $213.6 million and from the revolving credit facility of $84.7 million, net with repayments to the revolver of $103.2 million.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in our Annual Report on Form 10-K for the year ended December 31, 2012. There have been no material changes to those policies.

When used in the preparation of our unaudited condensed consolidated financial statements, estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our condensed consolidated financial position, results of operations and cash flows.

Other Items

Contractual Obligations

The following table summarizes our contractual obligations as of September 30, 2013 (in thousands):

	Payments due by Period				
	Total	**Less than 1 year**	**1-3 years**	**4-5 years**	**More than 5 years**
Revolving credit facility (1)	$ 306,150	$	$	$ 306,150	$
2020 Senior Notes (2)	$ 1,051,500	64,500	193,500	129,000	664,500
2021 Senior Notes (2)	$ 1,201,813	64,750	194,250	129,500	813,313
Drilling contracts (3)	$ 16,971	16,971			
Operating leases (3)	$ 9,132	1,575	4,899	2,138	520
Seismic contracts (3)	$ 3,192	3,192			
Asset retirement obligations (4)	$ 23,178				23,178
Other (3)	$ 2,696	2,696			
Total contractual obligations	**$ 2,614,632**	**$ 153,684**	**$ 392,649**	**$ 566,788**	**$ 1,501,511**

(1) Amount excludes interest on our revolving credit facility as both the amount borrowed and applicable interest rate are variable. As of September 30, 2013, we had $306.2 million of indebtedness outstanding under our revolving credit facility. See Note 9 to our unaudited condensed consolidated financial statements.

(2) Amount includes approximately $64.5 million and $64.8 million of interest per year for our 2020 Senior Notes and 2021 Senior Notes, respectively; see Note 9 to our unaudited condensed consolidated financial statements.

(3) See Note 13 to our unaudited condensed consolidated financial statements for a description of drilling contract, operating lease and seismic contract obligations.

(4) Amounts represent our estimate of future asset retirement obligations on an undiscounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environments. See Note 7 to our unaudited condensed consolidated financial statements.

Off-Balance Sheet Arrangements

We do not currently have any off-balance sheet arrangements.

Recent Accounting Pronouncements

The Company reviewed recently issued accounting pronouncements that became effective during the nine months ended September 30, 2013, and determined that none would have a material impact on our condensed consolidated financial statements.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses or gains, but rather indicators of reasonably possible losses or gains. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes other than speculative trading. These derivative instruments

Table of Contents

are discussed in Item 1. Financial Statements Notes to Unaudited Condensed Consolidated Financial Statements Note 4. Risk Management and Derivative Instruments.

Commodity Price Exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate due to changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past and expect to hedge a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil prices. As of September 30, 2013, we utilized fixed price swaps, collars and basis differential swaps to reduce the volatility of oil prices on a portion of our future expected oil production.

For derivative instruments recorded at fair value, the credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet.

The following is a summary of our commodity derivative contracts as of September 30, 2013:

	Hedged Volume	**Weighted-Average Fixed Price**			
Oil (Bbls):					
WTI Swaps 2013	1,086,120				$ 94.32
WTI Swaps 2014	4,344,450				$ 88.76
WTI Swaps 2015	1,820,000				$ 86.55
WTI Collars 2013	50,751	$	85.27	-	$ 100.70
WTI Collars 2014	164,400	$	88.49	-	$ 97.94
WTI to LLS Basis Differential Swaps 2013 (1)	330,760				$ 5.80
WTI to LLS Basis Differential Swaps 2014 (1)	501,000				$ 5.35
Natural Gas (Mmbtu):					
Swaps 2013 (2)	3,680,000				$ 4.09
Swaps 2014	9,125,000				$ 4.23
Collars 2013	558,249	$	3.68	-	$ 4.91
Collars 2014	1,685,004	$	3.99	-	$ 5.09
NGL (Bbls):					
NGL Swaps 2013	64,500				$ 63.42
NGL Swaps 2014	151,500				$ 62.16

(1) We enter into swap arrangements intended to fix the positive differential between the Louisiana Light Sweet (LLS) pricing and West Texas Intermediate (NYMEX WTI) pricing.

(2) Includes 1,240,000 Mmbtu that priced in the third quarter of 2013, but have yet to be cash settled.

		Nine Months Ended September 30, 2013 (in thousands)
Derivative fair value at period end - liability (included in balance sheet)	$	(31,110)
Realized net loss (included in the statement of operations)	$	(16,002)
Unrealized net loss (included in the statement of operations)	$	(26,997)

At September 30, 2013 and December 31, 2012, all of our commodity derivative contracts were with nine and five bank counterparties, respectively. Our policy is to net derivative liabilities and assets where there is a legally enforceable master netting agreement with the counterparty.

Interest Rate Risk. At September 30, 2013, we had indebtedness outstanding under our credit facility of $306.2 million, which bore interest at floating rates, we had $600 million outstanding in 2020 Senior Notes (placed October 1, 2012), which bore interest at 10.75%, and we had $700 million outstanding in 2021 Senior Notes (placed May 31, 2013), which bore interest at 9.25%. The average annual interest rate incurred on the credit facility for the three months ended September 30, 2013 and 2012 was 2.5% and 3.3%, respectively. The average annual interest rate incurred on the credit facility for the nine months ended September 30, 2013 and 2012 was 2.5% and 3.0%, respectively.

Table of Contents

A 1.0% increase in each of the average LIBOR and federal funds rate for the three months ended September 30, 2013 and 2012 would have resulted in an estimated $0.7 million and $0.5 million, respectively, increase in interest expense, of which a portion may be capitalized. A 1.0% increase in each of the average LIBOR and federal funds rate for the nine months ended September 30, 2013 and 2012 would have resulted in an estimated $1.6 million and $1.5 million, respectively, increase in interest expense, of which a portion may be capitalized.

We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. At September 30, 2013, we do not have any interest rate derivatives in place. In the future, we may utilize interest rate derivatives to mitigate our exposure to change in interest rates. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

During the period covered by this report, our management carried out an evaluation, under the supervision and with the participation of our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. Based upon that evaluation, our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer concluded that our disclosure controls and procedures at September 30, 2013 are effective.

Changes in Internal Control over Financial Reporting

There were no changes in our internal control over financial reporting during the quarter ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting except that during the quarter ended September 30, 2013, we continued implementing a new accounting, production and land IT system that we expect to have fully implemented during the fourth quarter of 2013.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 13 to our unaudited condensed consolidated financial statements entitled Commitments and Contingencies, which is incorporated in this item by reference.

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

Risk factors relating to us are contained in Item 1A of our Annual Report on Form 10-K for the year ended December 31, 2012 and our Quarterly Report on Form 10-Q for the three months ended March 31, 2013. No material change to such risk factors has occurred during the three months ended September 30, 2013.

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

None.

Item 3. Defaults upon Senior Securities

None.

Item 4. Mine Safety Disclosures

None.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibits included in this Report are listed in the Exhibit Index and incorporated herein by reference.

Table of Contents

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.

	MIDSTATES PETROLEUM COMPANY, INC.
Dated: November 14, 2013	/s/ John A. Crum John A. Crum Chief Executive Officer and President (Principal Executive Officer)
Dated: November 14, 2013	/s/ Thomas L. Mitchell Thomas L. Mitchell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Dated: November 14, 2013	/s/ Nelson M. Haight Nelson M. Haight Vice President and Chief Accounting Officer (Principal Accounting Officer)

Table of Contents

EXHIBIT INDEX

Exhibit Number	Exhibit Description
2.1	Master Reorganization Agreement, dated April 24, 2012, by and among the Company and certain of its affiliates, certain members of the Company s management and certain affiliates of First Reserve Corporation (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
2.2	Purchase and Sale Agreement, dated as of April 3, 2013, by and among Midstates Petroleum Company LLC, Panther Energy Company, LLC, Red Willow Mid-Continent, LLC and Linn Energy Holdings, LLC (filed as Exhibit 2.1 to the Company s Current Report on Form 8-K filed on April 4, 2013, and incorporated herein by reference).
3.1	Amended and Restated Certificate of Incorporation of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Midstates Petroleum Company, Inc. (filed as Exhibit 3.2 to the Company s Current Report on Form 8-K filed on April 25, 2012, and incorporated herein by reference).
3.3	Certificate of Designations of Series A Mandatorily Convertible Preferred Stock of Midstates Petroleum Company, Inc. (filed as Exhibit 3.1 to the Company s Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company s Registration Statement on Form S-1/A on February 29, 2012, and incorporated herein by reference).
4.2	Indenture, dated October 1, 2012, by and among the Company, Midstates Petroleum Company LLC and Wells Fargo Bank, National Association, as trustee, governing the 10.75% senior notes due 2020 (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.3	Registration Rights Agreement, dated October 1, 2012, by and among the Company, Midstates Petroleum Company LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein, relating to the 10.75% senior notes due 2020 (filed as Exhibit 4.2 to the Company s Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.4	Registration Rights Agreement, dated October 1, 2012, by and among the Company, Eagle Energy Production, LLC, FR Midstates Interholding, LP and certain other of the Company s stockholders (filed as Exhibit 4.3 to the Company s Current Report on Form 8-K filed on October 2, 2012, and incorporated herein by reference).
4.5	Indenture, dated May 31, 2013, by and among the Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and the Well Fargo Bank, National Association, as trustee, governing the 9.25% senior notes due 2021 (filed as Exhibit 4.1 to the Company s Current Report on Form 8-K filed on June 3, 2013, and incorporated herein by reference).
4.6	Registration Rights Agreement, dated May 31, 2013, by and among the Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC and Morgan Stanley & Co. LLC and SunTrust Robinson Humphrey, Inc., as representatives of the several initial purchasers named therein, relating to the 9.25% senior notes due 2021 (filed as Exhibit 4.2 to the Company s Current Report on Form 8-K filed on June 3, 2013, and incorporated herein by reference).
10.1	Assignment and Fourth Amendment to the Second Amended and Restated Credit Agreement, dated as of May 20, 2013, among Midstates Petroleum Company, Inc., Midstates Petroleum Company LLC, SunTrust Bank as administrative agent and the other lenders and parties party thereto (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on September 30, 2013, and incorporated herein by reference).
10.2***	Separation and Release Agreement, dated as of October 3, 2013 between Midstates Petroleum Company, Inc. and Stephen C. Pugh (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on October 4, 2013, and incorporated herein by reference).
31.1*	Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
31.2*	Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934.
32.1**	Certification of the Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
101.INS	XBRL Instance Document
101.SCH	XBRL Schema Document
101.CAL	XBRL Calculation Linkbase Document
101.DEF	XBRL Definition Linkbase Document
101.LAB	XBRL Labels Linkbase Document
101.PRE	XBRL Presentation Linkbase Document

*	Filed herewith
**	Furnished herewith
***	Management contract or compensatory plan or arrangement