Midstates Petroleum Company, Inc.
Form 10-Q
August 08, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, DC 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 June 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	**45-3691816**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
4400 Post Oak Parkway, Suite 1900 **Houston, Texas**	**77027**
(Address of principal executive offices)	(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	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 August 5, 2013 is shown below:

Class	**Number of shares outstanding**
Common stock, $0.01 par value	68,522,921

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MIDSTATES PETROLEUM COMPANY, INC.

QUARTERLY REPORT ON

FORM 10-Q

FOR THE THREE AND SIX MONTHS ENDED JUNE 30, 2013

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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.

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PART I - FINANCIAL INFORMATION

MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In thousands, except share amounts)

	June 30, 2013	December 31, 2012
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 12,285	$ 18,878
Accounts receivable:		
Oil and gas sales	61,650	35,618
Joint interest billing	20,901	10,815
Other	1,519	3,866
Commodity derivative contracts	9,006	5,695
Deferred income taxes	11,517	6,027
Other current assets	10,720	8,573
Total current assets	127,598	89,472
PROPERTY AND EQUIPMENT:		
Oil and gas properties, on the basis of full-cost accounting	2,744,032	1,836,664
Other property and equipment	7,907	5,038
Less accumulated depreciation, depletion, and amortization	(369,099)	(274,294)
Net property and equipment	2,382,840	1,567,408
OTHER ASSETS:		
Commodity derivative contracts	4,631	1,717
Other noncurrent assets	50,775	25,413
Total other assets	55,406	27,130
TOTAL	**$ 2,565,844**	**$ 1,684,010**
LIABILITIES AND EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 22,438	$ 29,196
Accrued liabilities	150,984	98,649
Commodity derivative contracts	8,883	7,582
Total current liabilities	182,305	135,427
LONG-TERM LIABILITIES:		
Asset retirement obligations	22,617	15,245
Commodity derivative contracts	495	3,943
Long-term debt	1,521,150	694,000
Deferred income taxes	196,115	190,625
Other long-term liabilities	1,088	1,189
Total long-term liabilities	1,741,465	905,002

COMMITMENTS AND CONTINGENCIES (Note 11)				
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, $338,000 and $325,000 liquidation value, respectively; 8% cumulative dividends; 325,000 shares issued and outstanding		3		3
Common stock, $0.01 par value, 300,000,000 shares authorized; 68,652,983 shares issued and 68,545,925 outstanding at June 30, 2013 and 66,619,711 shares issued and outstanding at December 31, 2012		686		666
Treasury stock		(605)		
Additional paid-in-capital		833,692		830,003
Retained deficit/accumulated loss		(191,702)		(187,091)
Total stockholders equity		642,074		643,581
TOTAL	**$**	**2,565,844**	**$**	**1,684,010**

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(In thousands, except per share amounts)

	For the Three Months Ended June 30, 2013	For the Three Months Ended June 30, 2012	For the Six Months Ended June 30, 2013	For the Six Months Ended June 30, 2012
REVENUES:				
Oil sales	$ 77,636	$ 48,056	$ 149,854	$ 93,138
Natural gas liquid sales	10,998	3,901	20,717	10,173
Natural gas sales	14,464	2,379	23,259	5,829
Gains on commodity derivative contracts net	22,421	48,143	2,297	23,478
Other	489	103	903	207
Total revenues	126,008	102,582	197,030	132,825
EXPENSES:				
Lease operating and workover	17,575	5,921	31,446	12,388
Severance and other taxes	6,579	6,272	12,534	11,648
Asset retirement accretion	313	164	567	298
Depreciation, depletion, and amortization	52,830	27,882	94,806	55,909
General and administrative	15,272	4,956	26,298	11,019
Acquisition and transaction costs	11,492		11,492	
Total expenses	104,061	45,195	177,143	91,262
OPERATING INCOME	21,947	57,387	19,887	41,563
OTHER INCOME (EXPENSE)				
Interest income	5	143	10	150
Interest expense net of amounts capitalized	(16,621)	(990)	(27,488)	(2,680)
Total other income (expense)	(16,616)	(847)	(27,478)	(2,530)
INCOME (LOSS) BEFORE TAXES	5,331	56,540	(7,591)	39,033
Income tax benefit (expense)	(1,993)	(168,917)	2,980	(168,917)
NET INCOME (LOSS)	$ 3,338	$ (112,377)	$ (4,611)	$ (129,884)
Preferred stock dividend (see Note 8)	(2,709)		(6,826)	
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON SHAREHOLDERS	$ 629	$ (112,377)	$ (11,437)	$ (129,884)
Basic and diluted net income (loss) per share attributable to common shareholders	$ 0.01	$ (1.85)	$ (0.17)	$ (2.39)

Weighted average number of common shares outstanding	68,441	60,887	65,699	54,261

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENT OF CHANGES IN STOCKHOLDERS EQUITY

(Unaudited)

(See Note 8 for Share History)

(In thousands)

	Preferred Stock	Common Stock	Treasury Stock	Additional Paid-in-Capital	Retained Deficit/ Accumulated Loss	Total Stockholders Equity
Balance as of December 31, 2012	**$ 3**	**$ 666**	**$**	**$ 830,003**	**$ (187,091)**	**$ 643,581**
Share-based compensation		20		$ 3,689	$	3,709
Acquisition of treasury stock			(605)			(605)
Net loss					(4,611)	(4,611)
Balance as of June 30, 2013	**$ 3**	**$ 686**	**$ (605)**	**$ 833,692**	**$ (191,702)**	**$ 642,074**

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

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MIDSTATES PETROLEUM COMPANY, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(In thousands)

	Six Months Ended June 30, 2013		Six Months Ended June 30, 2012	
CASH FLOWS FROM OPERATING ACTIVITIES:				
Net loss	$	(4,611)	$	(129,884)
Adjustments to reconcile net loss to net cash provided by operating activities:				
Unrealized gains on commodity derivative contracts, net		(8,372)		(35,157)
Asset retirement accretion		567		298
Depreciation, depletion, and amortization		94,806		55,909
Share-based compensation, net of amounts capitalized to oil and gas properties		3,014		682
Deferred income taxes		(2,980)		168,917
Amortization of deferred financing costs		2,264		376
Change in operating assets and liabilities:				
Accounts receivable oil and gas sales		(26,032)		5,015
Accounts receivable JIB and other		(7,739)		2,872
Other current assets		(2,147)		(3,491)
Accounts payable		(4,546)		(3,077)
Accrued liabilities		28,717		(2,371)
Other		(101)		(126)
Net cash provided by operating activities	$	72,840	$	59,963
CASH FLOWS FROM INVESTING ACTIVITIES:				
Investment in property and equipment		(259,584)		(184,245)
Investment in acquired property		(621,748)		
Net cash used in investing activities	$	(881,332)	$	(184,245)
CASH FLOWS FROM FINANCING ACTIVITIES:				
Proceeds from long-term borrowings		861,450		20,067
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 $6.1 million				213,839
Deferred financing costs		(24,646)		(2,112)
Repurchase of common stock		(605)		
Net cash provided by financing activities	$	801,899	$	128,627
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS		(6,593)		4,345
Cash and cash equivalents, beginning of period		18,878		7,344
Cash and cash equivalents, end of period	$	12,285	$	11,689

SUPPLEMENTAL INFORMATION:				
Non-cash transactions investments in property and equipment accrued not paid	$	104,161	$	79,400
Cash paid for interest, net of capitalized interest of $14.9 million and $2.4 million, respectively		19,494		2,763

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

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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 and natural gas liquids. 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 newly designated 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 (which also closed on October 1, 2012) of $600 million in aggregate principal amount of 10.75% senior unsecured notes due 2020.

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 June 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 and natural gas liquids. 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 six months ended June 30, 2013, and determined that none would have a material impact on the Company s condensed consolidated financial statements with the

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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.

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 June 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 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.

	Fair Value Measurements at June 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	$		$	11,428	$		$	11,428
Commodity derivative NGL swaps				3,461				3,461
Commodity derivative gas swaps				5,670				5,670
Commodity derivative oil collars				488				488
Commodity derivative gas collars				1,539				1,539
Commodity derivative differential swaps				147				147
Total assets				**22,733**				**22,733**
Liabilities:								
Commodity derivative oil swaps	$		$	17,430	$		$	17,430
Commodity derivative NGL swaps								
Commodity derivative gas swaps								
Commodity derivative oil collars				118				118
Commodity derivative gas collars				48				48
Commodity derivative differential swaps				878				878
Total liabilities	**$**		**$**	**18,474**	**$**		**$**	**18,474**

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	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 is exposed to fluctuations in crude oil, NGL and natural gas prices on its production. 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 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 June 30, 2013 would have been approximately $13.6 million.

Commodity Derivative Contracts

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

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Oil (Bbls):					
WTI Swaps 2013	2,172,214			$	94.12
WTI Swaps 2014	4,344,450			$	88.76
WTI Swaps 2015	1,820,000			$	86.55
WTI Collars 2013	101,502	$	85.27 -	$	100.70
WTI Collars 2014	164,400	$	88.49 -	$	97.94
WTI to LLS Basis Differential Swaps 2013 (1)	743,794			$	5.78
WTI to LLS Basis Differential Swaps 2014 (1)	501,000			$	5.35
Natural Gas (Mmbtu):					
Swaps 2013 (2)	7,360,000			$	4.09
Swaps 2014	9,125,000			$	4.23
Collars 2013	1,116,498	$	3.68 -	$	4.91
Collars 2014	1,685,004	$	3.99 -	$	5.09
NGL (Bbls):					
NGL Swaps 2013	129,000			$	63.42
NGL Swaps 2014	151,500			$	62.16

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(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 second quarter of 2013, but have yet to be cash settled.

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 condensed consolidated balance sheets at June 30, 2013 and December 31, 2012, respectively (in thousands):

Type	**Balance Sheet Location (1)**		**June 30, 2013**	**December 31, 2012**
Oil Swaps	Derivative financial instruments	Current Assets	$ 8,805	$ 16,004
Oil Swaps	Derivative financial instruments	Non-Current Assets	2,623	129
Oil Swaps	Derivative financial instruments	Current Liabilities	(16,872)	(11,485)
Oil Swaps	Derivative financial instruments	Non-Current Liabilities	(558)	(3,606)
NGL Swaps	Derivative financial instruments	Current Assets	3,031	1,624
NGL Swaps	Derivative financial instruments	Non-Current Assets	430	729
NGL Swaps	Derivative financial instruments	Current Liabilities		(336)
NGL Swaps	Derivative financial instruments	Non-Current Liabilities		(122)
Gas Swaps	Derivative financial instruments	Current Assets	4,473	
Gas Swaps	Derivative financial instruments	Non-Current Assets	1,197	
Gas Swaps	Derivative financial instruments	Current Liabilities		

Gas Swaps	Derivative financial instruments	Non-Current Liabilities		
Oil Collars	Derivative financial instruments	Current Assets	206	221
Oil Collars	Derivative financial instruments	Non-Current Assets	282	207
Oil Collars	Derivative financial instruments	Current Liabilities	(118)	(238)
Oil Collars	Derivative financial instruments	Non-Current Liabilities		(49)
Gas Collars	Derivative financial instruments	Current Assets	1,169	1,129
Gas Collars	Derivative financial instruments	Non-Current Assets	370	897
Gas Collars	Derivative financial instruments	Current Liabilities	(48)	(112)
Gas Collars	Derivative financial instruments	Non-Current Liabilities		(73)
Basis Differential Swaps	Derivative financial instruments	Current Assets	147	2,625
Basis Differential Swaps	Derivative financial instruments	Non-Current Assets		36
Basis Differential Swaps	Derivative financial instruments	Current Liabilities	(670)	(11,319)
Basis Differential Swaps	Derivative financial instruments	Non-Current Liabilities	(208)	(374)
Total			**$ 4,259**	**$ (4,113)**

(1) The fair value of 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 as of June 30, 2013 and December 31, 2012, respectively (in thousands):

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		June 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	$ 17,831	$ 8,825	$ 9,006
Commodity contracts	Derivative financial instruments - noncurrent	4,902	271	4,631
		$ 22,733	$ 9,096	$ 13,637
Derivative liabilities:				
Commodity contracts	Derivative financial instruments - current	$ 17,708	$ 8,825	$ 8,883
Commodity contracts	Derivative financial instruments - noncurrent	766	271	495
		$ 18,474	$ 9,096	$ 9,378

		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

Gains on Commodity Derivative Contracts

The Company does not designate its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, all gains and losses, including unrealized gains and losses from changes in the derivative instruments fair values, have been recorded in Gains on commodity derivative contracts net , within revenues in the condensed consolidated statements of operations.

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

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2013	2012	2013	2012
Realized net gains (losses)	$ (1,071)	$ (5,180)	$ (6,075)	$ (11,679)
Unrealized net gains (losses)	23,492	53,323	8,372	35,157

5. Property and Equipment

	June 30, 2013	December 31, 2012
	(in thousands)	
Oil and gas properties, on the basis of full-cost accounting:		
Proved properties	$ 2,277,758	$ 1,522,723
Unevaluated properties	466,274	313,941
Other property and equipment	7,907	5,038
Less accumulated depreciation, depletion, and amortization	(369,099)	(274,294)
Net property and equipment	$ 2,382,840	$ 1,567,408

Oil and Gas Properties

For the three and six months ended June 30, 2013, the Company capitalized $1.9 million and $3.4 million of internal costs directly related to exploration and development activities to oil and gas properties, respectively. For both the three and six months ended June 30, 2012, the Company capitalized $0.4 million of internal costs to oil and gas properties. 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.

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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 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 six months ended June 30, 2012 and 2013:

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2013		2012		2013		2012	
Depletion expense (in thousands)	$	52,256	$	27,792	$	93,845	$	55,732
Depletion expense (per Boe)	$	29.24	$	38.65	$	28.92	$	37.86

Unevaluated Property

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 $466.3 million at June 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 provided 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.

Ceiling Test

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 June 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 June 30, 2013 indicated the Company s capitalized costs were within 1% of the ceiling.

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 final determination of the fair value of, and the allocation to, the assets acquired and liabilities assumed in the Eagle Property Acquisition, remains to be finalized pending final post-closing adjustments; however, there have been no material adjustments thereto since the initial allocation. The Company expects to finalize the purchase accounting during the third quarter of 2013.

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

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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 following table summarizes (in thousands) the preliminary estimates of the assets acquired and the liabilities assumed in the acquisition. The final determination of fair value for certain assets and liabilities will be completed after the post-closing purchase price adjustments are finalized. These amounts will be finalized as soon as practicable, but no later than one year from the acquisition date.

		Anadarko Basin Acquisition
Oil and gas properties		
Proved	$	417,280
Unevaluated		207,400
Total assets acquired	$	624,680
Asset retirement obligations	$	6,296
Total liabilities assumed	$	6,296
Net assets acquired	$	618,384

The fair value measurements of the assets acquired and liabilities assumed are based on inputs that are not observable in the market and therefore represent Level 3 inputs. The fair values of oil and natural gas properties and asset retirement obligations were measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural gas properties include estimates of: (i) reserves; (ii) future operating and development costs; (iii) future commodity prices; (iv) estimated future cash flows; and (v) a market-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company s management at the time of the valuation and are the most sensitive and subject to change. As part of the determination of fair value, the Company also considered the range of values suggested by market transactions involving similar assets noting that these values were comparable to those determined under the cash flow approach.

Other Property Acquisitions

On April 1, 2013, the Company exercised preference rights and acquired additional acreage and producing wells in its Gulf Coast region for $3.4 million.

Actual and Pro Forma Information

Revenues attributable to the Eagle Property Acquisition and Anadarko Basin Acquisition included in the Company s consolidated statements of operations for the three months ended June 30, 2013 were $44.9 million and $14.2 million, respectively. Revenues attributable to the Eagle Property Acquisition and Anadarko Basin Acquisition included in the Company s consolidated statements of operations for the six months ended June 30, 2013 were $83.3 million and $14.2 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 six month periods ended June 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 June 30, 2013	For the Three Months Ended June 30, 2012	For the Six Months Ended June 30, 2013	For the Six Months Ended June 30, 2012
Revenues and other	$ 154,225	$ 183,766	$ 267,086	$ 275,308
Net income (loss)	9,949	(99,800)	(1,695)	(119,798)
Preferred stock dividends	(2,709)	(6,500)	(6,826)	(13,000)
Income (loss) available to common shareholders	$ 7,240	$ (106,300)	$ (8,521)	$ (132,798)
Net loss per common share - basic	$ 0.11	$ (1.75)	$ (0.13)	$ (2.45)
Net loss per common share - diluted	$ 0.11	$ (1.75)	$ (0.13)	$ (2.45)

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

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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. 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 $22.6 million and $15.2 million as of June 30, 2013 and December 31, 2012, respectively.

The liability has been accreted to its present value as of June 30, 2013 and December 31, 2012. The Company evaluated its wells and determined a range of abandonment dates through 2071.

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

Asset retirement obligations at January 1, 2013	$	15,245
Liabilities incurred		509
Liabilities assumed in Anadarko Basin Acquisition		6,296
Revisions		
Liabilities settled		
Current period accretion expense		567
Asset retirement obligations at June 30, 2013	**$**	**22,617**

7. Long-Term Debt

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

		June 30, 2013		December 31, 2012
Revolving credit facility, due 2018	$	221,150	$	94,000
Senior notes, due 2020		600,000		600,000
Senior notes, due 2021		700,000		
Long-term debt	**$**	**1,521,150**	**$**	**694,000**

Reserve-based Credit Facility

As of June 30, 2013, the Company s credit facility consisted of a $750 million senior revolving credit facility (the Credit Facility) with a borrowing base of $425 million, as recently redetermined in May 2013, when the borrowing base was increased from $285 million. At June 30, 2013, outstanding letters of credit obligations total $0.2 million.

On May 20, 2013, the Company entered into the Assignment and Third 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 Third Amendment).

The Third Amendment provided that, upon the consummation of the Anadarko Basin Acquisition and the satisfaction of other customary conditions, the Credit Facility would be automatically amended to accommodate the issuance, incurrence and/or compliance with the terms of the debt instruments that were to be issued or incurred in connection with the Anadarko Basin Acquisition. In addition, among other things, the Credit Agreement was amended to (a) permit the incurrence of $700 million of 2021 Senior Notes (discussed further below) in furtherance of the Anadarko Basin Acquisition without a corresponding reduction in the borrowing base, (b) provide for a borrowing base of $425 million, and (c) extend the maturity of the Credit Facility to May 31, 2018.

The Third Amendment also 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) 4.00:1.0, for the fiscal quarter ending March 31, 2013, (ii) 4.50:1.0, for the fiscal quarters ending June 30, 2013, September 30, 2013, December 31, 2013, March 31, 2014, and 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 Third Amendment became effective with the closing of the Anadarko Basin Acquisition on May 31, 2013.

Borrowings under the Credit Facility 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 June 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.

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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 October 1, 2013.

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.

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 June 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 June 30, 2013 was 1.9 to 1.0. At June 30, 2013, the Company s ratio of debt to EBITDA was 4.4.

Based upon the recent amendments to the Credit Facility, the Company believes its carrying amount at June 30, 2013 approximates its fair value (Level 2) due to the variable nature of the applicable interest rate and based on 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 Senior Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the Securities Act). 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 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. Under certain circumstances, in lieu of a registered exchange offer, the Company must use reasonable best efforts to file a shelf registration statement for the resale of the 2020 Senior Notes. If the Issuers fail to satisfy these obligations on a timely basis, the

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annual interest borne by the 2020 Senior Notes will be increased by up to 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective.

The estimated fair value of the 2020 Senior Notes was $606 million as of June 30, 2013 (Level 2 in the fair value measurement hierarchy based upon 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 both the three and six months ended June 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 Senior Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. 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 the Third 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.

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 with provisions substantially identical to that of the registration rights agreement entered into for the 2020 Senior Notes.

The estimated fair value of the 2021 Senior Notes was $672 million as of June 30, 2013 (Level 2 in the fair value measurement hierarchy), based on quoted market prices for these same debt securities. The effective annual interest rate for the 2021 Senior Notes was approximately 9.9% for both the three and six months ended June 30, 2013.

8. 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

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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

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 or, if conversion were to occur at the mandatory conversion date, the Company s average share price during the 15 days preceding such mandatory conversion date, subject to the limits described above.

For the three months ended March 31, 2013, the $4.1 million Series A Preferred Stock dividend (paid through the adjustment to the liquidation preference discussed above) was based upon the estimated fair value of 481,481 common shares that would have been issued had the Series A Preferred Stock dividend for the three months been converted into common shares using a conversion price of $13.50 per share.

The Company did not declare any dividends on the Series A Preferred Stock for the three months ended June 30, 2013; however, if they had, Series A Preferred Stockholders would have been entitled to $6.5 million of cash dividends or, if paid through an adjustment to the Series A Preferred Share liquidation preference, a number of additional common shares issuable upon conversion of the Series A Preferred Shares of between 500,741 and 614,545, the ultimate number of common shares dependent upon the then in effect conversion price. It is the Company s intention for the foreseeable future to pay Series A Preferred Share dividends through an adjustment to the liquidation preference. Therefore, for the three months ended June 30, 2013, the $2.7 million Series A Preferred Stock dividend which the Company intends to pay through the adjustment to the liquidation preference is based upon the estimated fair value of 500,741 common shares that would have been issued had the Series A Preferred Stock dividend for the three months been converted into common shares at a conversion price of $13.50 per share.

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

Number of Shares

	Preferred Stock	Common Stock	Treasury Stock
Balance as of December 31, 2012	**325,000**	**66,619,711**	
Grants of restricted stock		2,053,754	
Forfeitures of restricted stock		(20,482)	
Acquisition of treasury stock			(107,058)
Balance as of June 30, 2013	**325,000**	**68,652,983**	**(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 June 30, 2013, 1,609 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

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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 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 June 30, 2013 the Company had 2,725,142 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, shares granted under the LTIP to directors on or after April 1, 2013 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 following table summarizes the Company s non-vested share award activity for the six months ended June 30, 2013:

Shares

			Weighted Average Grant Date Fair Value
Non-vested shares outstanding at December 31, 2012	**985,358**	**$**	**12.61**
Granted	2,053,754	$	7.29
Vested	(293,488)	$	13.10
Forfeited	(20,482)	$	8.06
Non-vested shares outstanding at June 30, 2013	**2,725,142**	**$**	**8.58**

Unrecognized expense as of June 30, 2013 for all outstanding restricted stock awards was $20.9 million and will be recognized over a weighted average period of 2.4 years.

At June 30, 2013, 3,945,351 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 June 30,				For the Six Months Ended June 30,			
		2013		2012		2013		2012
Incentive units	$		$		$		$	
2012 LTIP restricted shares		1,770		682		3,014		682
Total share-based compensation expense, net of amounts capitalized to oil and gas properties	**$**	**1,770**	**$**	**682**	**$**	**3,014**	**$**	**682**

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For the three and six months ended June 30, 2013, the Company capitalized $0.4 million and $0.6 million of qualifying share-based compensation costs to oil and gas properties. For the three and six months ended June 30, 2012, the Company did not capitalize any share-based compensation costs to oil and gas properties.

9. 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 six months ended June 30, 2013, the Company estimated its effective annual tax rate for 2013 to be approximately 39.3%. 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 a change in expected state income taxes due to additional property acquisitions in various taxing states (most notably Oklahoma and Texas). 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 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.

As of June 30, 2013, the Company has not recorded a reserve for any uncertain tax positions.

10. Earnings (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 share and per share amounts) is a calculation of the basic and diluted net income (loss) for the three and six months ended June 30, 2013 and 2012.

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	For the Three Months Ended June 30, 2013	For the Three Months Ended June 30, 2012 (1)	For the Six Months Ended June 30, 2013	For the Six Months Ended June 30, 2012 (1)
Numerator				
Net income (loss)	3,338	(112,377)	(4,611)	(129,884)
Less:				
Preferred stock dividend	(2,709)		(6,826)	
Undistributed earnings to participating securities	(170)			
Net income (loss) attributable to common shareholders - basic and diluted	459	(112,377)	(11,437)	(129,884)
Denominator				
Weighted average basic and diluted common shares outstanding (2)	68,441	60,887	65,699	54,261
Basic and diluted earnings (loss) per common share	$0.01	$(1.85)	$(0.17)	$(2.39)

(1) For the 2012 comparable period, the Company was not a public company until April 25, 2012.

(2) At June 30, 2013, there were no other dilutive securities outstanding to consider for the period presented as the nonvested restricted stock grants and Series A Preferred Stock had already been considered as part of the two-class method.

The aggregate number of common shares outstanding at June 30, 2013 was 68,545,925, of which 2,725,142 were unvested restricted shares. The aggregate number of shares of Series A Preferred Stock outstanding at June 30, 2013 was 325,000, representing on an as-converted basis approximately 25.5 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.

11. Commitments and Contingencies

Contractual Obligations

At June 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	$ 21,361	19,520	1,841		
Non-cancellable office lease commitments	$ 8,500	709	1,438	1,460	4,893
Seismic contracts	$ 5,770	5,770			
Net minimum commitments	$ 35,631	$ 25,999	$ 3,279	$ 1,460	$ 4,893

Litigation

Clovelly Oil Company

The Company is a defendant in an action brought by Clovelly Oil Company (the Plaintiff or Clovelly) in the 13th Judicial District Court in Louisiana in May 2009. The Plaintiff alleges that the Company is subject to an unrecorded Joint Operating Agreement (JOA) dated July 16, 1972, as a result of the Company s 2007 purchase of a 43.75% working interest in certain acreage. The Plaintiff further alleges that the Company is bound by the 1972 JOA and that the Plaintiff is entitled to 56.25% of the Company s 242.28-acre Crowell Land & Mineral lease. The Company was not a signatory to the JOA, and believes that it is protected by the Louisiana Public Records Doctrine, which generally provides that instruments involving real property are without effect as to third parties unless the instrument is filed of record in the appropriate mortgage or conveyance records of the parish in which such property is located.

The Company made a motion for summary judgment on all of the Plaintiff s claims, and the 13th Judicial District Court granted that motion on August 14, 2009. The Plaintiff appealed the district court s decision to the Third Circuit Court of Appeal, and on April 7, 2010, the Third Circuit Court of Appeal reversed and remanded the case to the district court for trial. On August 9, 2010, the Plaintiff amended its original petition to add Wells Fargo Bank, N. A., which holds a mortgage on the acreage, as a defendant.

On September 27, 2011, the district court granted the Company s motion for partial summary judgment declaring that the JOA does not apply to any new leases acquired after July 16, 1972 which are not extension or renewal leases. The district court also granted a

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motion for summary judgment filed by Wells Fargo asserting that, as a mortgage holder of a mortgage covering the applicable lease, Wells Fargo is protected by the Public Records Doctrine. The Plaintiff again appealed.

On June 6, 2012, the Third Circuit Court of Appeal reversed the district court s partial summary judgment decision that the JOA does not apply to any new leases. It held that, if the Company is subject to the JOA, then the JOA applies to leases acquired by the Company after the 2007 purchase that are within the acreage covered by the JOA. Separately, the Third Circuit Court of Appeal upheld the district s court decision that Wells Fargo is protected by the Public Records Doctrine. The Third Circuit Court of Appeal then remanded the case to the district court for a determination of whether the Company had assumed the obligations under the JOA.

On December 14, 2012 the Louisiana Supreme Court granted the Company s petition seeking a review and reversal of the Third Circuit Court of Appeal s September 2012 decision in the Company s ongoing litigation with Clovelly Oil. On March 19, 2013, the Louisiana Supreme Court held that the JOA does not apply to new leases acquired by the Company after the time the JOA was executed on July 16, 1972 and unanimously reversed the Third Circuit Court of Appeals decision and reinstated the 13th Judicial District Court s ruling where it granted the Company s motion for partial summary judgment.

On May 3, 2013, the Louisiana Supreme Court denied Clovelly s Application for Rehearing. The Company intends to seek dismissal of Clovelly s claims with the 13th Judicial District Court, as the Supreme Court s ruling held for the Company on the central matter at issue in the action. This dismissal would eliminate any exposure to the Company from this lawsuit, as all leases at issue in the matter were acquired after July 16, 1972.

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.

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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 report on Form 10-Q for quarter ended March 31, 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 report on Form 10-Q for the quarter ended March 31, 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

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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.

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 in 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) of interests in producing oil and natural gas assets and unevaluated leasehold acreage in Texas and Oklahoma. 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. In conjunction with the Anadarko Basin Acquisition and the 2021 Senior Notes, our revolving credit facility was amended to, among other things, increase the borrowing base thereunder to $425 million and extend the maturity date to 2018, effective May 31, 2013. See Liquidity and Capital Resources Significant Sources of Capital 2021 Senior Notes Offering for more information.

With the closing of the Anadarko Basin Acquisition, we acquired approximately 138,900 net acres in the Anadarko Basin, of which approximately 101,400 net acres are located in Texas, with the remainder located in Oklahoma. The assets target the oil and liquids rich Cleveland, Marmaton, Cottage Grove and Tonkawa formations at depths ranging from 6,000 to 8,000 feet. Approximately 60% of the acreage is held by production and the acquisition adds approximately 298 gross producing wells that are approximately 78% operated with an approximate 65% average working interest and 51% net revenue interest.

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.

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Operations Update

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.

Many of the oilfields in this trend were discovered by major oil companies in the 1940s and 1950s, but were not fully developed due to then-prevailing oil prices, the adoption of a state level severance tax in Louisiana, restrictive production allowables and other regulatory limitations. We have applied modern formation evaluation and 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 June 30, 2013, our properties in the Gulf Coast region consisted of approximately 170 gross active producing wells, 96% of which we operate and in which we held an average working interest of 96%.

During the three months ended June 30, 2013, our average production from these properties was 6,540 net Boe/d, consisting of 4,075 Bbls of oil, 1,089 Bbls of natural gas liquids (NGLs), and 8,257 Mcf of natural gas. Our average production from these properties for the first quarter of 2013 was 6,740 net Boe/d, consisting of 4,517 Bbls of oil, 977 Bbls of NGLs, and 7,480 Mcf of natural gas. Production from the Gulf Coast declined by 3% versus the first quarter of 2013, primarily due to base production decline and reduced drilling during the second quarter.

During the second quarter of 2013, we invested approximately $58 million for exploration, development, facilities and lease and seismic acquisition and completed six wells in the Gulf Coast area. During the third quarter of 2013, we currently plan to invest approximately $25 million and drill between two to three horizontal wells.

As of June 30, 2013, we had accumulated approximately 118,120 net acres in the trend, including options to acquire an aggregate of approximately 53,110 targeted net acres. We currently have one drilling rig 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 18,950 net acres under lease. In the second quarter of 2013, 93% of our drilling and completion capital was concentrated on three of our primary fields: Pine Prairie, South Bearhead Creek and North Coward s Gully. We spud four gross wells in the Gulf Coast region in the second quarter of 2013, including one horizontal well and one vertical well in the South Bearhead Creek field and two horizontal wells in North Cowards Gully field.

Of these four wells, three were producing and one was drilling at quarter-end. We brought a total of six wells in the Gulf Coast region into production during the second quarter of 2013, consisting of two vertical wells, one in South Bearhead Creek and one in Pine Prairie, and four horizontal wells or horizontal sidetracks, one at South Bearhead Creek and three at North Cowards Gully.

During the second quarter, based upon drilling results to date, we determined that future development of our West Gordon field was not warranted at this time and impaired our remaining unproved property costs to the full cost pool subject to amortization and removed approximately 4.6 million MBoe in proved undeveloped reserves from our reserve base.

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. The 3D data was delivered during the second quarter of 2013 and we have begun evaluation of the results. We may acquire additional acreage within the 3D seismic shoot pending evaluation of the results. At June 30, 2013, we held approximately 101,970 gross (99,160 net) acres in these expansion areas, through leases and options, and we are currently evaluating prospects on this acreage.

In the second quarter of 2013, we did not spud or complete any wells in our Gulf Coast expansion areas. We are currently evaluating the results from our 3D seismic shoot and, depending upon the results our evaluation, we may spud between one and two wells on prospects within this acreage in the future.

Mid-Continent Region

Our Mid-Continent assets were acquired on October 1, 2012 and May 31, 2013, and at June 30, 2013, consisted of approximately 103,000 net prospective acres in the Mississippian Lime/Hunton, with approximately 82,600 net acres in Woods and Alfalfa Counties of Oklahoma; approximately 5,660 net acres in Kansas and approximately 14,740 net acres in Lincoln County, Oklahoma, which produces primarily natural gas from the Hunton formation. In addition, we held 138,900 net acres in the Anadarko Basin, consisting of 101,400 net acres in Texas with the remainder in western Oklahoma. We currently intend to develop these oil and liquids rich properties using horizontal wells.

Mississippian Lime/Hunton

At June 30, 2013, our properties in the Mississippian Lime/Hunton area consisted of approximately 166 gross active producing wells, 84% of which we operate and in which we held an average working interest of 73%.

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We spud 21 horizontal wells in the Mississippian Lime/Hunton in the second quarter of 2013. Of these 21 wells, five were producing, 11 awaiting completion and five were drilling at quarter-end. We brought a total of 12 horizontal wells in the area into production during the second quarter of 2013.

During the three months ended June 30, 2013, our average production from these properties was 10,426 net Boe/d consisting of 3,404 Bbls of oil, 1,776 Bbls of NGLs, and 31,476 Mcf of natural gas. Our average production from these properties for the first quarter of 2013 was 9,468 net Boe/d consisting of 3,422 Bbls of oil, 2,105 Bbls of NGLs, and 23,646 Mcf of natural gas. Production increased by 10% versus the first quarter of 2013, primarily due to increased drilling activity. Our NGL production during the second quarter was adversely impacted by the bypass of a significant portion of our natural gas production due to processing plant capacity constraints. The bypassing of gas resulted in short-term lower realized NGL yields and a higher percentage of natural gas sold during the quarter. These processing plant constraints were remedied in early June with the startup of a new third party owned and operated NGL plant.

Our current development drilling is targeting the Mississippian Lime interval. In the second quarter of 2013, we invested approximately $77 million and spud 21 horizontal wells; during the third quarter of 2013, we plan to invest approximately $105 million in the drilling of between 20 and 25 wells. Our plans are to continue to actively develop opportunities in this area. We currently have a total of five operated drilling rigs targeting the Mississippian Lime interval in Oklahoma.

Anadarko Basin

At June 30, 2013, our properties in the Anadarko Basin area consisted of approximately 298 gross active producing wells, 78% of which we operate and in which we held an average working interest of 65%.

We spud three wells in the Anadarko Basin area since May 31, 2013. Of these three wells, all were drilling at quarter-end. In addition, we completed three wells after assuming operations.

During the three months ended June 30, 2013, our production from these properties contributed 2,668 net Boe/d to our daily average for the period and consisted of 1,268 Bbls of oil, 555 Bbls of NGLs, and 5,075 Mcf of natural gas. We did not have production from these properties prior to the closing of the Anadarko Basin Acquisition on May 31, 2013.

Our current development drilling is targeting the Cleveland, Marmaton, Cottage Grove and Tonkawa formations. In the second quarter of 2013, we invested approximately $6 million and spud three horizontal wells; for the third quarter of 2013, we plan to invest approximately $45 million in the drilling of between 16 and 18 wells. Our plans are to continue to actively develop opportunities in this area. We currently have a total of four operated drilling rigs operating in the Anadarko Basin assets.

Capital Expenditures

During the three and six months ended June 30, 2013, we incurred capital expenditures of $149.4 million and $282.2 million, respectively, including capitalized interest, which consisted primarily of (in thousands):

	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2013
Drilling and completion activities	$ 130,067	$ 246,577
Acquisition of acreage and seismic data	8,133	16,369
Facilities and other	3,329	4,325
Capitalized interest	7,861	14,915
Total capital expenditures incurred	$ 149,390	$ 282,186

Excluding the Anadarko Basin Acquisition and capitalized interest, of the $141.5 million spent during the second quarter in 2013, $58.0 million was spent in the Gulf Coast region and $82.5 million was spent in the Mid-Continent region.

Revolving Credit Facility

In conjunction with the Anadarko Basin Acquisition and the 2021 Senior Notes, our revolving credit facility was amended to increase the borrowing base thereunder to $425 million and extend the maturity date to 2018, effective May 31, 2013. 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 38 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 June 30,				For the Six Months Ended June 30,			
	2013		2012		2013		2012	
	(in thousands)				(in thousands)			
REVENUES:								
Oil sales	$ 77,636	75%	$ 48,056	88%	$ 149,854	77%	$ 93,138	85%
Natural gas liquid sales	10,998	11%	3,901	7%	20,717	11%	10,173	10%
Natural gas sales	14,464	14%	2,379	5%	23,259	12%	5,829	5%
Total oil, natural gas liquids, and natural gas sales	103,098	100%	54,336	100%	193,830	100%	109,140	100%
Realized gains (losses) on commodity derivative contracts, net	(1,071)	-5%	(5,180)	-11%	(6,075)	-264%	(11,679)	-50%
Unrealized gains on commodity derivative contracts, net	23,492	105%	53,323	111%	8,372	364%	35,157	150%
Gains on commodity derivative contracts net	22,421	100%	48,143	100%	2,297	100%	23,478	100%
Other	489		103		903		207	
Total revenues	**$ 126,008**		**$ 102,582**		**$ 197,030**		**$ 132,825**	

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Production

	For the Three Months Ended June 30,			For the Six Months Ended June 30, 2013		
	2013	2012	% Change	2013	2012	% Change
PRODUCTION DATA:						
Oil (MBbls)	796	447	78%	1,510	852	77%
Natural gas liquids (MBbls)	311	98	218%	589	225	162%
Natural gas (MMcf)	4,078	1,047	289%	6,879	2,369	190%
Oil equivalents (MBoe)	1,787	719	149%	3,245	1,472	120%
Oil (Boe/day)	8,747	4,910	78%	8,345	4,682	78%
Natural gas liquids (Boe/day)	3,419	1,076	218%	3,251	1,238	163%
Natural gas (Mcf/day)	44,808	11,507	289%	38,005	13,015	192%
Average daily production (Boe/d)	19,634	7,904	148%	17,930	8,090	122%

Prices

	For the Three Months Ended June 30, 2013			For the Six Months Ended June 30, 2013		
	2013	2012	% Change	2013	2012	% Change
AVERAGE SALES PRICES:						
Oil, without realized derivatives (per Bbl)	$ 97.54	$ 107.56	-9%	$ 99.21	$ 109.30	-9%
Oil, with realized derivatives (per Bbl)	$ 94.86	$ 95.97	-1%	$ 94.13	$ 95.59	-2%
Natural gas liquids, without realized derivatives (per Bbl)	$ 35.34	$ 39.83	-11%	$ 35.20	$ 45.14	-22%
Natural gas liquids, with realized derivatives (per Bbl)	$ 37.41	(a)		$ 36.89	(a)	
Natural gas, without realized derivatives (per Mcf)	$ 3.55	$ 2.27	56%	$ 3.38	$ 2.46	37%
Natural gas, with realized derivatives (per Mcf)	$ 3.65	(a)		$ 3.47	(a)	

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

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

Oil, natural gas liquids and natural gas sales revenues

Our oil, natural gas and NGLs sales revenues increased by $48.8 million, or 90%, to $103.1 million during the three months ended June 30, 2013, as compared to $54.3 million during the three months ended June 30, 2012.

Our oil sales revenues increased by $29.5 million, or 61%, to $77.6 million during the three months ended June 30, 2013, as compared to $48.1 million for the three months ended June 30, 2012. Oil volumes sold increased 3,837 Boe/day or 78% to 8,747 Boe/day for the three months ended June 30, 2013 from 4,910 Boe/day for the three months ended June 30, 2012. This increase in oil volumes sold was attributable to the addition of 4,672 Boe/day of production volumes from our Mid-Continent area, which consists 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 835 Boe/day primarily due to base production decline and reduced drilling activity during the 2013 period. During the three months ended June 30, 2012, all of our production was from our Gulf Coast region. Average oil sales prices, without realized derivatives, decreased by $10.02 per barrel, or 9%, to $97.54 per barrel during the three months ended June 30, 2013 as compared to $107.56 per barrel for the three months ended June 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 $7.1 million, or 182%, to $11.0 million during the three months ended June 30, 2013, as compared to $3.9 million for the three months ended June 30, 2012. NGL volumes sold increased 2,343 Boe/day, or 218%, to 3,419 Boe/day for the three months ended June 30, 2013 from 1,076 Boe/day for the three months ended June 30, 2012. This increase in NGL volumes sold was attributable to the addition of 2,330 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, combined with a 13 Boe/day increase in production from our Gulf Coast area. Average NGL sales prices, without realized derivatives, decreased by $4.49 per barrel, or 11%, to $35.34 per barrel during the three months ended June 30, 2013 as compared to $39.83 per barrel for the corresponding period in 2012.

Our natural gas sales revenues increased by $12.1 million, or 504%, to $14.5 million during the three months ended June 30, 2013, as compared to $2.4 million for the three months ended June 30, 2012. Natural gas volumes sold increased 33,301 Mcf/day or 289%, to 44,808 Mcf/day for the three months ended June 30, 2013 from 11,507 Mcf/day for the three months ended June 30, 2012. This increase in natural gas volumes sold was attributable to the addition of 36,551 Mcf/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 decrease in production of 3,250 Mcf/day from our Gulf Coast area. Average natural gas sales prices, without realized derivatives, increased by $1.28 per Mcf, or 56%, to $3.55 per Mcf during the three months ended June 30, 2013 as compared to $2.27 per Mcf for the three months ended June 30, 2012.

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Gains/losses on commodity derivative contracts - net

Our mark-to-market (MTM) derivative positions moved from an unrealized gain of $53.3 million for the three months ended June 30, 2012 to an unrealized gain of $23.5 million for the three months ended June 30, 2013. The MTM change resulted from higher average hedge volumes and favorable market price movements 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, natural gas and NGL hedging instruments associated with those acquired properties. The NYMEX WTI closing price on June 29, 2012 (the last day of trading for the period) was $84.96 per barrel compared to a closing price of $96.56 per barrel on June 28, 2013 (the last day of trading for the period).

The realized loss on derivatives for the three months ended June 30, 2013 was $1.1 million, compared to a realized loss of $5.2 million for the three months ended June 30, 2012. As discussed above, with the closing of the Eagle Property Acquisition, we assumed the related natural gas and NGL hedging instruments. Therefore, our realized gains/losses for the three months ended June 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 June 30, 2013	
	Realized Gain (Loss) (in thousands)	**Average Sales Price**
Oil commodity contracts	$ (2,130)	$ 94.86
Natural gas liquids commodity contracts	$ 643	$ 37.41
Natural gas commodity contracts	$ 416	$ 3.65
	$ (1,071)	

Six Months Ended June 30, 2013 as Compared to the Six Months Ended June 30, 2012

Oil, natural gas liquids and natural gas sales revenues

Our oil, natural gas and NGLs sales revenues increased by $84.7 million, or 78%, to $193.8 million during the six months ended June 30, 2013, as compared to $109.1 million during the six months ended June 30, 2012.

Our oil sales revenues increased by $56.8 million, or 61%, to $149.9 million during the six months ended June 30, 2013, as compared to $93.1 million for the six months ended June 30, 2012. Oil volumes sold increased 3,663 Boe/day or 78% to 8,345 Boe/day for the six months ended June 30, 2013 from 4,682 Boe/day for the six months ended June 30, 2012. This increase in oil volumes sold was attributable to the addition of 4,050 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 388 Boe/day from our Gulf Coast area. During the six months ended June 30, 2012, all of our production was from our Gulf Coast region. Average oil sales prices, without realized derivatives, decreased by $10.09 per barrel, or 9%, to $99.21 per barrel during the six months ended June 30, 2013 as compared to $109.30 per barrel for the six months ended June 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 $10.5 million, or 103%, to $20.7 million during the six months ended June 30, 2013, as compared to $10.2 million for the six months ended June 30, 2012. NGL volumes sold increased 2,013 Boe/day, or 163%, to 3,251 Boe/day for the six months ended June 30, 2013 from 1,238 Boe/day for the six months ended June 30, 2012. This increase in NGL volumes sold was attributable to the addition of 2,218 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 205 Boe/day decrease in production from our Gulf Coast area. Average NGL sales prices, without realized derivatives, decreased by $9.94 per barrel, or 22%, to $35.20 per barrel during the six months ended June 30, 2013 as compared to $45.14 per barrel for the corresponding period in 2012.

Our natural gas sales revenues increased by $17.5 million, or 302%, to $23.3 million during the six months ended June 30, 2013, as compared to $5.8 million for the six months ended June 30, 2012. Natural gas volumes sold increased 24,990 Mcf/day or 192%, to 38,005 Mcf/day for the six months ended June 30, 2013 from 13,015 Mcf/day for the six months ended June 30, 2012. This increase in natural gas volumes sold was attributable to the addition of 30,134 Mcf/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 decrease in production of 5,144 Mcf/day from our Gulf Coast area. Average natural gas sales prices, without realized derivatives, increased by $0.92 per Mcf, or 37%, to $3.38 per Mcf during the six months ended June 30, 2013 as compared to $2.46 per Mcf for the six months ended June 30, 2012.

Gains/losses on commodity derivative contracts - net

Our mark-to-market (MTM) derivative positions moved from an unrealized gain of $35.2 million for the six months ended June 30, 2012 to an unrealized gain of $8.4 million for the six months ended June 30, 2013. The MTM change resulted from higher average

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hedge volumes and favorable market price movements 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, natural gas and NGL hedging instruments associated with those acquired properties. The NYMEX WTI closing price on June 29, 2012 (the last day of trading for the period) was $84.96 per barrel compared to a closing price of $96.56 per barrel on June 28, 2013 (the last day of trading for the period).

The realized loss on derivatives for the six months ended June 30, 2013 was $6.1 million, compared to a realized loss of $11.7 million for the six months ended June 30, 2012. As discussed above, with the closing of the Eagle Property Acquisition, we assumed the related natural gas and NGL hedging instruments. Therefore, our realized gains/losses for the six months ended June 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:

	Six Months Ended June 30, 2013			
	Realized Gain (Loss)		Average Sales Price	
	(in thousands)			
Oil commodity contracts	$	(7,683)	$	94.13
Natural gas liquids commodity contracts	$	995	$	36.89
Natural gas commodity contracts	$	613	$	3.47
	$	(6,075)		

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 June 30,								Six Months Ended June 30,							
	2013		2012		2013		2012		2013		2012		2013		2012	
	(in thousands)				(per Boe)				(in thousands)				(per Boe)			
EXPENSES:																
Lease operating and workover	$	17,575	$	5,921	$	9.83	$	8.24	$	31,446	$	12,388	$	9.69	$	8.42
Severance and other taxes		6,579		6,272	$	3.68	$	8.72		12,534		11,648	$	3.86	$	7.91
Asset retirement accretion		313		164	$	0.18	$	0.23		567		298	$	0.17	$	0.20
Depreciation, depletion, and amortization		52,830		27,882	$	29.56	$	38.78		94,806		55,909	$	29.21	$	37.98
General and administrative		15,272		4,956	$	8.55	$	6.89		26,298		11,019	$	8.10	$	7.49
Acquisition and transaction costs		11,492			$	6.43	$			11,492			$	3.54	$	
Total expenses	**$**	**104,061**	**$**	**45,195**	**$**	**58.23**	**$**	**62.86**	**$**	**177,143**	**$**	**91,262**	**$**	**54.57**	**$**	**62.00**

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

Lease operating and workover expenses

Lease operating and workover expenses increased $11.7 million, or 198%, to $17.6 million for the three months ended June 30, 2013 compared to $5.9 million for the three months ended June 30, 2012. Lease operating expenses increased $10.0 million, or 191%, to $15.2 million, for the three months ended June 30, 2013 as compared to $5.2 million for the related period in 2012. Of this increase, approximately $7.8 million relates to the Mid-Continent area, which was acquired on October 1, 2012 and May 31, 2013, as described above. During the period, we experienced higher costs on our Mississippian Lime assets attributable to surface maintenance and repairs following adverse weather. The remaining $2.2 million increase is related to costs associated with an increase in Gulf Coast producing well count, which increased by 49 wells period-over-period, and higher salt water disposal costs. We have undertaken a number of actions which we believe will reduce future salt water disposal costs in the Gulf Coast Region. We also continue to take steps in the Mississippian Lime area to increase the reliability of the power grid by, among other things, upgrading electrical lines. Additionally, we have programs in place to replace diesel powered generators with natural gas generators which should favorably impact future operating costs. Workover expenses increased $1.7 million, or 263%, to $2.4 million for the three months ended June 30, 2013 compared to $0.7 million for the three months ended June 30, 2012. Of this increase, approximately $2.2 million relates to the Mid-Continent area, which consists of properties acquired on October 1, 2012 and May 31, 2013, partially offset by a decrease in Gulf Coast workover costs of $0.5 million. Across both regions, we completed 11 workovers during the three months ended June 30, 2013, as compared to 10 workovers in the 2012 period. Lease operating and workover expenses increased to $9.83 per Boe for the three months ended June 30, 2013, an increase of $1.59, or 19%, over the corresponding period in 2012. This increase was primarily attributable to the factors discussed above.

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Severance and other taxes

	Three Months Ended June 30, 2013	2012
Total oil, natural gas, and natural gas liquids sales	$ 103,098	$ 54,336
Severance taxes	5,362	5,469
Ad valorem	1,217	803
Severance and other taxes	6,579	6,272
Severance taxes as a percentage of sales	5.2%	10.1%
Severance and other taxes as a percentage of sales	6.4%	11.5%

Severance and other taxes increased $0.3 million, or 5%, to $6.6 million for the three months ended June 30, 2013 compared to $6.3 million for the three months ended June 30, 2012. Severance taxes decreased $0.1 million, or 2%, to $5.4 million for the three months ended June 30, 2013, as compared to $5.5 million for the three months ended June 30, 2012. This decrease was attributable to the lower effective severance tax rate in Oklahoma applicable to production from the Mid-Continent region. Ad valorem taxes increased $0.4 million, or 50%, to $1.2 million for the three months ended June 30, 2013 as compared to $0.8 million for the three months ended June 30, 2012, corresponding to a related increase in producing wells.

Depreciation, depletion and amortization (DD&A)

DD&A expense increased $24.9 million, or 89%, to $52.8 million for the three months ended June 30, 2013 compared to $27.9 million for the three months ended June 30, 2012. The DD&A rate for the 2013 period was $29.56 per Boe compared to $38.78 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 relating to the Eagle Property Acquisition and on May 31, 2013 as a result of the Anadarko Basin Acquisition.

General and administrative (G&A)

Our G&A expenses increased by $10.3 million, or 206%, to $15.3 million for the three months ended June 30, 2013, compared to $5.0 million for the three months ended June 30, 2012. The increase is attributable to $2.3 million in payments to Eagle Energy Production, LLC and Panther Energy Company, LLC under the respective Transition Services Agreements, $1.3 million in professional fees and approximately $5.9 million in additional employee related expenses (including salary, share-based compensation expense and bonus) resulting from an increase in headcount from 86 full time employees at June 30, 2012 to 158 full time employees at June 30, 2013.

Acquisition and transaction costs

Our acquisition and transaction costs were $11.5 million for the three months ended June 30, 2013, compared to no acquisition and transaction costs for the three months ended June 30, 2012. These costs represent our expenses through June 30, 2013 related to the Anadarko Basin Acquisition and are primarily attributable to bridge financing fees, due diligence costs and legal fees that are required to be expensed under US GAAP.

Six Months Ended June 30, 2013 as Compared to the Six Months Ended June 30, 2012

Lease operating and workover expenses

Lease operating and workover expenses increased $19.0 million, or 153%, to $31.4 million for the six months ended June 30, 2013 compared to $12.4 million for the six months ended June 30, 2012. Lease operating expenses increased $15.5 million, or 143%, to $26.3 million, for the six months ended June 30, 2013 as compared to $10.8 million for the related period in 2012. Of this increase, approximately $12.2 million relates to the Mid-Continent area, which was acquired on October 1, 2012 and May 31, 2013, as described above. During the period, due to extreme winter weather, we experienced power failures and the temporary shut-in of our production in the Mississippian Lime region of our Mid-Continent area. As a result, we incurred additional lease operating expense during the period related to restoring power and production in our Mid-Continent area. The remaining $3.3 million increase is related to costs associated with the increase in Gulf Coast producing well count, which increased by 49 wells period-over-period, as well as higher salt water disposal costs. The Company has undertaken a number of actions which it believes will reduce future salt water disposal costs in the Gulf Coast Region. Workover expenses increased $3.5 million, or 218%, to $5.1 million for the six months ended June 30, 2013 compared to $1.6 million for the six months ended June 30, 2012. Of this increase, approximately $3.9 million relates to the Mid-Continent area, which was acquired on October 1, 2012 and May 31, 2013, as described above. Partially offsetting this increase period-to-period, is a decrease in the Gulf Coast area, driven by fewer workovers completed on Gulf Coast wells. Across both regions, we completed 27 workovers during the six months ended June 30, 2013, as compared to 19 workovers in the 2012 period. Lease operating and workover expenses increased to $9.69 per Boe for the six months ended June 30, 2013, an increase of $1.27, or 15%, over the corresponding period in 2012. This increase was primarily attributable to the factors discussed above.

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Severance and other taxes

	Six Months Ended June 30, 2013		2012	
Total oil, natural gas, and natural gas liquids sales	$	193,830	$	109,140
Severance taxes		10,215		9,952
Ad valorem		2,319		1,696
Severance and other taxes		12,534		11,648
Severance taxes as a percentage of sales		5.3%		9.1%
Severance and other taxes as a percentage of sales		6.5%		10.7%

Severance and other taxes increased $0.9 million, or 8%, to $12.5 million for the six months ended June 30, 2013 compared to $11.6 million for the six months ended June 30, 2012. Severance taxes increased $0.2 million, or 2%, to $10.2 million for the six months ended June 30, 2013, as compared to $10.0 million for the six months ended June 30, 2012. This increase was attributable to higher oil, natural gas and NGL sales, partially offset by the lower effective severance tax rate in Oklahoma applicable to production from the Mid-Continent region. Ad valorem taxes increased $0.7 million, or 44%, to $2.3 million for the six months ended June 30, 2013 as compared to $1.6 million for the six months ended June 30, 2012, corresponding to a related increase in producing wells.

Depreciation, depletion and amortization (DD&A)

DD&A expense increased $38.9 million, or 70%, to $94.8 million for the six months ended June 30, 2013 compared to $55.9 million for the six months ended June 30, 2012. The DD&A rate for the 2013 period was $29.21 per Boe compared to $37.98 per Boe for the 2012 period. The decrease in DD&A rate was due to the addition of reserves in the Mid-Continent region on October 1, 2012 relating to the Eagle Property Acquisition and on May 31, 2013 as a result of the Anadarko Basin Acquisition.

General and administrative (G&A)

Our G&A expenses increased by $15.3 million, or 139%, to $26.3 million for the six months ended June 30, 2013, compared to $11.0 million for the six months ended June 30, 2012. The increase is attributable to approximately $8.6 million in additional employee related costs (including salary, share-based compensation, and bonus) related to an increase in headcount from 86 full time employees at June 30, 2012 to 158 employees at June 30, 2013, $2.1 million in professional fees, $3.0 million in payments to Eagle Energy Production, LLC and Panther Energy Company, LLC under the respective Transition Services Agreements and $1.1 million in other taxes.

Acquisition and transaction costs

Our acquisition and transaction costs were $11.5 million for the six months ended June 30, 2013, compared to no acquisition and transaction costs for the six months ended June 30, 2012. These costs represent our expenses through June 30, 2013 related to the Anadarko Basin Acquisition and are primarily attributable to bridge financing fees due diligence costs and legal fees that are required to be expensed under US GAAP.

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Other Income (Expenses)

	For the Three Months Ended June 30, 2013	2012	For the Six Months Ended June 30, 2013	2012
	(in thousands)		(in thousands)	
OTHER INCOME (EXPENSE)				
Interest income	$ 5	$ 143	$ 10	$ 150
Interest expense	(24,482)	(2,701)	(42,403)	(5,064)
Capitalized Interest	7,861	1,711	14,915	2,384
Interest expense net of amounts capitalized	$ (16,621)	$ (990)	$ (27,488)	$ (2,680)
Total other income (expense)	**$ (16,616)**	**$ (847)**	**$ (27,478)**	**$ (2,530)**

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

Interest expense

Interest expense for the three months ended June 30, 2013 and 2012 was $24.5 million and $2.7 million, respectively. The increase in interest expense was primarily due to the issuance of $700 million of 9.25% senior unsecured notes in May 2013 (2021 Senior Notes) and $600 million of 10.75% senior unsecured notes in October 2012 (2020 Senior Notes). Our average outstanding balance under the revolver was $221.0 million during the three months ended June 30, 2013, compared to $163.7 million for the three months ended June 30, 2012, and related to $1.4 million of the total interest expense of $24.5 million for 2013. Of the remainder of the interest expense, $16.1 million was interest incurred under the 2020 Senior Notes, $5.7 million was interest incurred under the 2021 Senior Notes and $1.3 million represented amortization of deferred financing costs. Of the total interest expense, $7.9 million and $1.7 million was capitalized, resulting in $16.6 million and $1.0 million in interest expense, net of capitalized interest, for the three months ended June 30, 2013 and 2012, respectively.

Six Months Ended June 30, 2013 as Compared to the Six Months Ended June 30, 2012

Interest expense

Interest expense for the six months ended June 30, 2013 and 2012 was $42.4 million and $5.1 million, respectively. The increase in interest expense was primarily due to the issuance of $700 million in 2021 Senior Notes and $600 million in 2020 Senior Notes. Our average outstanding balance under the revolver was $179.6 million during the six months ended June 30, 2013, compared to $199.2 million for the six months ended June 30, 2012, and related to $2.2 million of the total interest expense of $42.4 million for 2013. Of the remainder of the interest expense, $32.2 million was interest incurred under the 2020 Senior Notes, $5.7 million was interest incurred under the 2021 Senior Notes and $2.3 million represented amortization of deferred financing costs. Of the total interest expense, $14.9 million and $2.4 million was capitalized, resulting in $27.5 million and $2.7 million in interest expense, net of capitalized interest, for the six months ended June 30, 2013 and 2012, respectively.

Provision for Income Taxes

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

Our income tax expense was $2.0 million and $168.9 million for the three months ended June 30, 2013 and 2012, respectively. The resulting income tax expense for the three months ended June 30, 2013 represents an effective tax rate (including state income taxes) of approximately 37.4%. 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.

Six Months Ended June 30, 2013 as Compared to the Six Months Ended June 30, 2012

For the six months ended June 30, 2013, we had an income tax benefit of $3.0 million and for the six months ended June 30, 2012, we had income tax expense of $168.9 million. The resulting income tax benefit for the six months ended June 30, 2013 represents an effective tax benefit rate (including state income taxes) of approximately 39.3%. 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 June 30, 2013, our liquidity was $216 million, consisting of $204 million of available borrowing capacity under our revolving credit facility (which at that date, consisted of a borrowing base of $425 million) and $12 million of cash and cash equivalents.

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We plan to finance our capital expenditures for the remainder of 2013 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 secure 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 second quarter of 2014.

Significant Sources of Capital

Reserve-based Credit Facility

As of June 30, 2013, our credit facility consisted of a $750 million senior revolving credit facility (the Credit Facility) with a borrowing base of $425 million, as recently redetermined in May 2013 in connection with the Anadarko Basin Acquisition.

On May 20, 2013, we entered into the Assignment and Third 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 Third Amendment).

The Third Amendment provided that, upon the consummation of the Anadarko Basin Acquisition and the satisfaction of other customary conditions, the Credit Facility would be automatically amended to accommodate the issuance, incurrence and/or compliance with the terms of the debt instruments that were to be issued or incurred in connection with the Anadarko Basin Acquisition. In addition, among other things, the Credit Agreement was amended to (a) permit the incurrence of $700 million of 2021 Senior Notes (discussed further below) in furtherance of the Anadarko Basin Acquisition without a corresponding reduction in borrowing base, (b) provide for a borrowing base of $425 million, and (c) extend the maturity of the Credit Facility to May 31, 2018.

The Third Amendment also 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) 4.00:1.0, for the fiscal quarter ending March 31, 2013, (ii) 4.50:1.0, for the fiscal quarters ending June 30, 2013, September 30, 2013, December 31, 2013, March 31, 2014, and 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 Third Amendment became effective with the closing of the Anadarko Basin Acquisition on May 31, 2013.

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 October 1, 2013.

Under the terms of the Credit Facility, we are required to repay the amount by which the principal balance of our outstanding loans and our 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.

The Credit Facility contains financial covenants, in addition to the maximum ratio of debt to EBITDA, 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 our ability to make any dividends, distributions or redemptions.

As of June 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 June 30, 2013 was 1.9 to 1.0 and our ratio of debt to EBITDA was 4.4.

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 Senior Notes) in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. 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 the 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 obligating us 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 offering for registered notes having substantially the same terms as the 2020 Senior Notes and evidencing the same indebtedness as the 2020 Senior Notes. Under certain circumstances, in lieu of a registered exchange offer, we must use reasonable best efforts to file a shelf registration statement for the resale of the 2020 Senior Notes. If the Issuers fail to satisfy these obligations on a timely basis, the annual interest borne by the 2020 Senior Notes will be increased by up to 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective.

2021 Senior Notes Offering

On May 31, 2013, we issued $700 million in aggregate principal amount of 9.25% senior notes due 2021 in a private placement conducted pursuant to Rule 144A and Regulation S under the Securities Act. 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 the Third Amendment to the revolving credit facility, to repay $34.3 million in outstanding borrowings under the 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. 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 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 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 with provisions substantially identical to that of the registration rights agreement entered into for the 2020 Senior Notes.

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 38.

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

	For the Six Months Ended June 30, 2013	For the Six Months Ended June 30, 2012
Net cash provided by operating activities	$ 72,840	$ 59,963
Net cash used in investing activities	(881,332)	(184,245)
Net cash provided by financing activities	801,899	128,627
Net change in cash	$ (6,593)	$ 4,345

Cash flows provided by operating activities

Net cash provided by operating activities was $72.8 million and $60.0 million for the six months ended June 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 higher production and partially offset by lower realized oil and NGL prices, offset by unfavorable working capital changes.

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Cash flows used in investing activities

Net cash used in investing activities was $881.3 million and $184.2 million during the six months ended June 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.

Cash flows provided by financing activities

Net cash provided by financing activities was $801.9 million and $128.6 million for the six months ended June 30, 2013 and 2012, respectively. During the six months ended June 30 2013, cash was sourced through the revolving credit facility, with draws of $161.5 million during the period and repayments of $34.3 million, and $700 million from the 2021 Senior Notes placed in May 2013. During the six months ended June 30, 2012, cash sourced from financing activities was primarily from our initial public offering of $213.8 million, net with repayments to the revolving credit facility $103.2 million.

Critical Accounting Policies and Estimates

A discussion of our critical accounting policies and estimates is included in Midstates Petroleum Company, Inc. s Annual Report on Form 10-K. 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 June 30, 2013 (in thousands):

Payments due by Period

	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Revolving credit facility (1)	$ 221,150			221,150	
2020 Senior Notes (2)	$ 1,067,625	64,500	193,500	129,000	680,625
2021 Senior Notes (2)	$ 1,218,000	64,750	194,250	129,500	829,500
Drilling contracts (3)	$ 21,361	21,361			
Operating leases (3)	$ 8,500	1,428	4,441	2,087	544
Seismic contracts (3)	$ 5,770	5,770			
Asset retirement obligations (4)	$ 22,617				22,617
Total contractual obligations	**$ 2,565,023**	**$ 157,809**	**$ 392,191**	**$ 481,737**	**$ 1,533,286**

(1) Amount excludes interest on our revolving credit facility as both the amount borrowed and applicable interest rate are variable. As of June 30, 2013, we had $221.2 million of indebtedness outstanding under our revolving credit facility. See Note 7 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 7 to our unaudited condensed consolidated financial statements.

(3) See Note 11 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 6 to our unaudited condensed consolidated financial statements.

Off-Balance Sheet Arrangements

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

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Recent Accounting Pronouncements

The Company reviewed recently issued accounting pronouncements that became effective during the six months ended June 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 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 June 30, 2013, we utilized fixed price swaps, collars, deferred-premium puts 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 June 30, 2013:

	Hedged Volume	Weighted-Average Fixed Price
Oil (Bbls):		

WTI Swaps - 2013	2,172,214				$	94.12
WTI Swaps - 2014	4,344,450				$	88.76
WTI Swaps - 2015	1,820,000				$	86.55
WTI Collars - 2013	101,502	$	85.27	-	$	100.70
WTI Collars -2014	164,400	$	88.49	-	$	97.94
WTI to LLS Basis Differential Swaps - 2013 (1)	743,794				$	5.78
WTI to LLS Basis Differential Swaps -2014 (1)	501,000				$	5.35
Natural Gas (Mmbtu):						
Swaps - 2013 (2)	7,360,000				$	4.09
Swaps - 2014	9,125,000				$	4.23
Collars - 2013	1,116,498	$	3.68	-	$	4.91
Collars - 2014	1,685,004	$	3.99	-	$	5.09
NGL (Bbls):						
NGL Swaps - 2013	129,000				$	63.42
NGL Swaps - 2014	151,500				$	62.16

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(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 second quarter of 2013, but have yet to be cash settled.

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		Six Months Ended June 30, 2013 (in thousands)
Derivative fair value at period end - asset (included in balance sheet)	$	4,259
Realized net loss (included in the statement of operations)	$	(6,075)
Unrealized net gain (included in the statement of operations)	$	8,372

At June 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 June 30, 2013, we had indebtedness outstanding under our credit facility of $221.2 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 this combined indebtedness for the three months ended June 30, 2013 and 2012 was 8.8% and 2.5%, respectively. The average annual interest rate incurred on this combined indebtedness for the six months ended June 30, 2013 and 2012 was 9.0% and 2.9%, respectively. A 1.0% increase in each of the average LIBOR and federal funds rate for the three months ended June 30, 2013 and 2012 would have resulted in an estimated $2.6 million and $0.4 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 six months ended June 30, 2013 and 2012 would have resulted in an estimated $4.5 million and $1.0 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 June 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 June 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 June 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 June 30, 2013, we began 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 11 to our unaudited condensed consolidated financial statements entitled Commitments and Contingencies, which is incorporated in this item by reference.

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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 fiscal 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 June 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.

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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: August 8, 2013	/s/ John A. Crum John A. Crum Chief Executive Officer and President (Principal Executive Officer)
Dated: August 8, 2013	/s/ Thomas L. Mitchell Thomas L. Mitchell Executive Vice President and Chief Financial Officer (Principal Financial Officer)
Dated: August 8, 2013	/s/ Nelson M. Haight Nelson M. Haight Vice President and Controller (Principal Accounting Officer)

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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 Third 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 May 22, 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

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* Filed herewith

** Furnished herewith