Oasis Petroleum Inc.
Form 10-Q
November 07, 2013
Table of Contents

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2013
or
¨ 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: 1-34776

Oasis Petroleum Inc.
(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	80-0554627 (I.R.S. Employer Identification No.)
1001 Fannin Street, Suite 1500 Houston, Texas (Address of principal executive offices)	77002 (Zip Code)

(281) 404-9500
(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 ý No ¨

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

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

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

Number of shares of the registrant’s common stock outstanding at November 4, 2013: 93,701,254 shares.

Table of Contents

OASIS PETROLEUM INC.
FORM 10-Q
FOR THE QUARTER ENDED SEPTEMBER 30, 2013
TABLE OF CONTENTS

Table of Contents

PART I — FINANCIAL INFORMATION
Item 1. — Financial Statements (Unaudited)
Oasis Petroleum Inc.
Condensed Consolidated Balance Sheet
(Unaudited)

	September 30, 2013	December 31, 2012
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$125,440	$213,447
Restricted cash	986,210	—
Short-term investments	—	25,891
Accounts receivable — oil and gas revenues	155,068	110,341
Accounts receivable — joint interest partners	120,058	99,194
Inventory	18,358	20,707
Prepaid expenses	7,440	1,770
Advances to joint interest partners	1,170	1,985
Derivative instruments	374	19,016
Deferred income taxes	8,683	—
Other current assets	473	335
Total current assets	1,423,274	492,686
Property, plant and equipment		
Oil and gas properties (successful efforts method)	3,044,515	2,348,128
Other property and equipment	157,926	49,732
Less: accumulated depreciation, depletion, amortization and impairment	(589,173)	(391,260)
Total property, plant and equipment, net	2,613,268	2,006,600
Derivative instruments	3,405	4,981
Deferred costs and other assets	43,436	24,527
Total assets	$4,083,383	$2,528,794
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$39,468	$12,491
Advances from joint interest partners	13,211	21,176
Revenues and production taxes payable	133,083	71,553
Accrued liabilities	198,493	189,863
Accrued interest payable	22,873	30,096
Derivative instruments	17,060	1,048
Deferred income taxes	—	4,558
Total current liabilities	424,188	330,785
Long-term debt	2,360,000	1,200,000
Asset retirement obligations	26,999	22,956
Derivative instruments	852	380
Deferred income taxes	293,156	177,671
Other liabilities	2,310	1,997
Total liabilities	3,107,505	1,733,789
Commitments and contingencies (Note 13)		
Stockholders' equity		
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,854,867 issued and 93,690,494 outstanding at September 30, 2013; 93,432,712	926	925

issued and 93,303,298 outstanding at December 31, 2012		
Treasury stock, at cost; 164,373 and 129,414 shares at September 30, 2013 and December 31, 2012, respectively	(5,220)	(3,796)
Additional paid-in-capital	666,770	657,943
Retained earnings	313,402	139,933
Total stockholders' equity	975,878	795,005
Total liabilities and stockholders' equity	$4,083,383	$2,528,794

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

1

Table of Contents

Oasis Petroleum Inc.
Condensed Consolidated Statement of Operations
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$286,952	$178,748	$770,445	$461,857
Well services and midstream revenues	18,546	5,963	37,939	10,484
Total revenues	305,498	184,711	808,384	472,341
Expenses				
Lease operating expenses	21,831	16,134	59,586	37,979
Well services and midstream operating expenses	10,319	5,420	19,877	7,104
Marketing, transportation and gathering expenses	5,688	2,744	19,856	7,283
Production taxes	26,823	16,433	70,309	43,419
Depreciation, depletion and amortization	72,728	57,684	205,779	140,783
Exploration expenses	463	336	2,712	3,171
Impairment of oil and gas properties	56	36	762	2,607
General and administrative expenses	16,728	13,886	47,238	39,622
Total expenses	154,636	112,673	426,119	281,968
Operating income	150,862	72,038	382,265	190,373
Other income (expense)				
Net gain (loss) on derivative instruments	(39,817)	(22,441)	(41,838)	33,568
Interest expense, net of capitalized interest	(22,854)	(20,979)	(65,429)	(48,952)
Other income	23	1,147	1,097	2,521
Total other income (expense)	(62,648)	(42,273)	(106,170)	(12,863)
Income before income taxes	88,214	29,765	276,095	177,510
Income tax expense	33,715	11,451	102,626	66,712
Net income	$54,499	$18,314	$173,469	$110,798
Earnings per share:				
Basic (Note 11)	$0.59	$0.20	$1.88	$1.20
Diluted (Note 11)	0.59	0.20	1.87	1.20
Weighted average shares outstanding:				
Basic (Note 11)	92,449	92,186	92,408	92,164
Diluted (Note 11)	92,836	92,416	92,838	92,343

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

Table of Contents

Oasis Petroleum Inc.
Condensed Consolidated Statement of Changes in Stockholders’ Equity
(Unaudited)
(In thousands)

	Common Stock		Treasury Stock		Additional Paid-in-Capital	Retained Earnings	Total Stockholders’ Equity
	Shares	Amount	Shares	Amount			
Balance as of December 31, 2012	93,303	$925	129	$(3,796)	$ 657,943	$ 139,933	$795,005
Stock-based compensation	422	1	—	—	8,827	—	8,828
Treasury stock – tax withholdings	(35)	—	35	(1,424)	—	—	(1,424)
Net income	—	—	—	—	—	173,469	173,469
Balance as of September 30, 2013	93,690	$926	164	$(5,220)	$ 666,770	$ 313,402	$975,878

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

Table of Contents

Oasis Petroleum Inc.
Condensed Consolidated Statement of Cash Flows
(Unaudited)

	Nine Months Ended September 30,	
	2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income	$173,469	$110,798
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	205,779	140,783
Impairment of oil and gas properties	762	2,607
Deferred income taxes	102,244	66,648
Derivative instruments	41,838	(33,568)
Stock-based compensation expenses	8,411	6,627
Debt discount amortization and other	2,693	2,038
Working capital and other changes:		
Change in accounts receivable	(67,487)	(69,163)
Change in inventory	(8,820)	(26,790)
Change in prepaid expenses	(5,175)	(2,009)
Change in other current assets	(138)	413
Change in other assets	(63)	(119)
Change in accounts payable and accrued liabilities	82,246	79,079
Change in other current liabilities	—	4,784
Change in other liabilities	922	—
Net cash provided by operating activities	536,681	282,128
Cash flows from investing activities:		
Capital expenditures	(654,175)	(777,516)
Acquisition of oil and gas properties	(133,061)	—
Increase in restricted cash	(986,210)	—
Derivative settlements	(5,135)	2,784
Purchases of short-term investments	—	(126,213)
Redemptions of short-term investments	25,000	19,994
Advances from joint interest partners	(7,965)	17,508
Net cash used in investing activities	(1,761,546)	(863,443)
Cash flows from financing activities:		
Proceeds from credit facility	160,000	—
Proceeds from issuance of senior notes	1,000,000	400,000
Purchases of treasury stock	(1,424)	(1,299)
Debt issuance costs	(21,718)	(7,955)
Net cash provided by financing activities	1,136,858	390,746
Decrease in cash and cash equivalents	(88,007)	(190,569)
Cash and cash equivalents:		
Beginning of period	213,447	470,872
End of period	$125,440	$280,303
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$10,530	$71,572
Change in asset retirement obligations	4,173	7,774

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

OASIS PETROLEUM INC.
Notes to Condensed Consolidated Financial Statements (Unaudited)
1. Organization and Operations of the Company
Organization
Oasis Petroleum Inc. (together with its subsidiaries, “Oasis” or the “Company”) was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a holding company for Oasis Petroleum LLC (“OP LLC”), the Company’s predecessor, which was formed as a Delaware limited liability company on February 26, 2007. In connection with its initial public offering in June 2010 and related corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company’s common stock. In 2007, Oasis Petroleum North America LLC (“OPNA”), a Delaware limited liability company, was formed to conduct domestic oil and natural gas exploration and production activities. In 2008, Oasis Petroleum International LLC (“OPI”), a Delaware limited liability company, was formed to conduct business development activities outside of the United States of America. As of September 30, 2013, OPI had no business activities or material assets. In 2011, the Company formed Oasis Well Services LLC (“OWS”), a Delaware limited liability company, to provide well services to OPNA, and Oasis Petroleum Marketing LLC (“OPM”), a Delaware limited liability company, to provide marketing services to OPNA. In 2013, the Company formed Oasis Midstream Services LLC (“OMS”), a Delaware limited liability company, to provide midstream services to OPNA. As part of the formation of OMS, the Company transferred substantially all of its salt water disposal and other midstream assets from OPNA to OMS.
Nature of Business
The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the Williston Basin. The Company’s proved and unproved oil and natural gas properties are located in the Montana and North Dakota areas of the Williston Basin and are owned by OPNA. The Company also operates a marketing business (OPM), a well services business (OWS) and a midstream services business (OMS), all of which are complementary to its primary development and production activities. Both OWS and OMS are separate reportable business segments.
2. Summary of Significant Accounting Policies
Basis of Presentation
The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly owned subsidiaries. The accompanying condensed consolidated financial statements of the Company have not been audited by the Company’s independent registered public accounting firm, except that the Condensed Consolidated Balance Sheet at December 31, 2012 is derived from audited financial statements. All significant intercompany transactions have been eliminated in consolidation. Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for the fair presentation, have been included. 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.
These interim financial statements 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 Company’s audited consolidated financial statements and notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2012 (“2012 Annual Report”).
Significant Accounting Policies
There have been no material changes to the Company’s critical accounting policies and estimates from those disclosed in the 2012 Annual Report other than those noted below.
Restricted Cash

Restricted cash represents aggregate net proceeds from the issuance of $1,000.0 million of 6.875% senior unsecured notes due 2022, which were held in escrow as of September 30, 2013 pending the closing of the acquisition of oil and gas properties in the Company’s West Williston project area (see Note 7 – Long-Term Debt and Note 15 – Subsequent Events). If

Table of Contents

the acquisition had not closed prior to December 12, 2013, the Company would have been required to use the restricted cash to redeem all of the notes due 2022 at a redemption price equal to 100% of the initial offering price, plus accrued and unpaid interest through the date of redemption.

3. Inventory

Equipment and materials consist primarily of tubular goods, well equipment to be used in future drilling or repair operations, well fracturing equipment, chemicals and proppant, all of which are stated at the lower of cost or market with cost determined on an average cost method. Crude oil inventories include oil in tank and line fill and are valued at the lower of average cost or market value. Inventory consists of the following:

	September 30, 2013	December 31, 2012
	(In thousands)	
Equipment and materials	$12,498	$16,438
Crude oil inventory	5,860	4,269
Total inventory	$18,358	$20,707

4. Property, Plant and Equipment

The following table sets forth the Company's property, plant and equipment:

	September 30, 2013	December 31, 2012
	(In thousands)	
Proved oil and gas properties (1)	$2,916,453	$2,271,711
Less: Accumulated depreciation, depletion, amortization and impairment	(568,567)	(383,564)
Proved oil and gas properties, net (2)	2,347,886	1,888,147
Unproved oil and gas properties	128,062	76,417
Total oil and gas properties, net	2,475,948	1,964,564
Other property and equipment	157,926	49,732
Less: Accumulated depreciation	(20,606)	(7,696)
Other property and equipment, net (2)	137,320	42,036
Total property, plant and equipment, net	$2,613,268	$2,006,600

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $24.0 million and $20.7 million at September 30, 2013 and December 31, 2012, respectively.

(2) The Company reclassed substantially all of its salt water disposal and other midstream assets from proved oil and gas properties to other property and equipment, effective January 1, 2013.

As a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and natural gas properties of $56,000 and $0.8 million for the three and nine months ended September 30, 2013, respectively, and $36,000 and $2.6 million for the three and nine months ended September 30, 2012, respectively. No impairment charges on proved oil and natural gas properties were recorded for the three and nine months ended September 30, 2013 or 2012.

Asset acquisitions. On September 26, 2013, the Company acquired certain oil and natural gas assets totaling approximately 25,000 net acres in its East Nesson project area for cash consideration of $54.8 million, subject to further customary post close adjustments (the "East Nesson Acquisitions"). As part of the East Nesson Acquisitions, the Company also agreed to invest, expend and/or incur expenses of $8.2 million in connection with drilling and completion activities for certain wells (see Note 13 - Commitments and Contingencies). Additionally, the Company paid a deposit of $72.5 million in September 2013 for the acquisition of assets in its West Williston project area (see Note 15 - Subsequent Events), which is included in oil and gas properties on the Company's Condensed Consolidated Balance Sheet at September 30, 2013.

5. Fair Value Measurements

In accordance with the Financial Accounting Standards Board's ("FASB") authoritative guidance on fair value measurements, the Company's financial assets and liabilities are measured at fair value on a recurring basis. The

Company

6

Table of Contents

recognizes its non-financial assets and liabilities, such as asset retirement obligations (“ARO”) and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

As defined in the authoritative guidance, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). To estimate fair value, the Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable.

The authoritative guidance establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (“Level 1” measurements) and the lowest priority to unobservable inputs (“Level 3” measurements). The three levels of the fair value hierarchy are as follows:

Level 1 — Unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs, other than unadjusted quoted prices in active markets included in Level 1, are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 — Pricing inputs are generally less observable from objective sources, requiring internally developed valuation methodologies that result in management’s best estimate of fair value.

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety 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 fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis:

	At fair value as of September 30, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$11,274	$—	$—	$11,274
Commodity derivative instruments (see Note 6)	—	3,779	—	3,779
Total assets	$11,274	$3,779	$—	$15,053
Liabilities:				
Commodity derivative instruments (see Note 6)	$—	$17,912	$—	$17,912
Total liabilities	$—	$17,912	$—	$17,912

	At fair value as of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$66,387	$—	$—	$66,387
Commodity derivative instruments (see Note 6)	—	23,997	—	23,997
Total assets	$66,387	$23,997	$—	$90,384
Liabilities:				

Commodity derivative instruments (see Note 6)	$—	$1,428	$—	$1,428
Total liabilities	$—	$1,428	$—	$1,428

7

Table of Contents

The Level 1 instruments presented in the tables above consist of money market funds included in cash and cash equivalents on the Company's Condensed Consolidated Balance Sheet at September 30, 2013 and December 31, 2012. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identified the money market funds as Level 1 instruments due to the fact that the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include oil collars, swaps and puts. The fair values of the Company's commodity derivative instruments are based upon a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The Company compares the third-party preparer's valuation to counterparty valuation statements, investigating any significant differences, and analyzes monthly valuation changes in relation to movements in crude oil forward price curves. The determination of the fair value for derivative instruments also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in a net asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a net liability position is based on the Company's market credit spread. Based on these calculations, the Company recorded a downward adjustment to the fair value of its net derivative liability of $0.4 million at September 30, 2013 and a downward adjustment to the fair value of its net derivative asset of $29,000 at December 31, 2012.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, restricted cash, short-term investments, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At September 30, 2013, the Company's cash equivalents were all Level 1 assets. The carrying amount of the Company's long-term debt reported in the Condensed Consolidated Balance Sheet at September 30, 2013 is $2,360.0 million, which includes $2,200.0 million of senior unsecured notes and $160.0 million of borrowings under the revolving credit facility (see Note 7 – Long-Term Debt). The fair value of the Company's senior unsecured notes, which are Level 1 liabilities, is $2,325.0 million at September 30, 2013.

Nonfinancial Assets and Liabilities

Asset retirement obligations. The carrying amount of the Company's ARO in the Condensed Consolidated Balance Sheet at September 30, 2013 is $27.4 million (see Note 8 – Asset Retirement Obligations). The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments, including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Impairment. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs. No impairment charges on proved oil and natural gas properties were recorded for the three and nine months ended September 30, 2013 or 2012.

6. Derivative Instruments

Table of Contents

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of September 30, 2013, the Company utilized two-way and three-way costless collar options, put spreads, swaps and swaps with sub-floors to reduce the volatility of oil prices on a significant portion of its future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX West Texas Intermediate ("WTI") crude oil index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A put spread is a combination of a purchased put and a sold put, and in this case does not include a sold call, allowing the volumes under this contract to have no established maximum price (ceiling). A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A swap with a sub-floor is a swap coupled with a sold put (sub-floor) at which point the minimum price would be WTI crude oil index price plus the difference between the swap and the sold put strike price.

All derivative instruments are recorded on the balance sheet as either assets or liabilities measured at fair value (see Note 5 – Fair Value Measurements). Derivative assets and liabilities arising from the Company's derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both cash settlements and non-cash changes in fair value, are recognized in the other income (expense) section of the Condensed Consolidated Statement of Operations as a net gain or loss on derivative instruments. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making a payment to or receiving a payment from the counterparty. These cash settlements are reflected as investing activities in the Company's Condensed Consolidated Statement of Cash Flows.

As of September 30, 2013, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the average WTI crude oil index price:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices				Fair Value Asset (Liability)
			Swap	Sub-Floor	Floor	Ceiling	
		(Barrels)	($/Barrel)				(In thousands)
2013	Two-way collars	836,000			$92.11	$103.45	$(2,636)
2013	Three-way collars	832,330		$67.63	92.01	110.97	(118)
2013	Put spreads	168,670		70.89	90.89		4
2013	Swaps	880,500	$97.29				(5,118)
2014	Two-way collars	1,510,000			90.77	102.06	(159)
2014	Three-way collars	3,530,530		70.30	90.65	105.64	2,497
2014	Put spreads	11,470		70.00	90.00		10
2014	Swaps	2,218,500	95.87				(2,486)
2014	Swaps with sub-floors	2,004,000	92.60	70.00			(7,202)
2015	Two-way collars	108,500			90.00	99.86	284
2015	Three-way collars	263,500		70.59	90.59	105.25	723
2015	Swaps	108,500	93.07				148
2015	Swaps with sub-floors	186,000	92.60	70.00			(80)
							$(14,133)

The following table summarizes the location and fair value of all outstanding commodity derivative instruments recorded in the balance sheet for the periods presented:

9

Table of Contents

Fair Value of Derivative Instrument Assets (Liabilities)

Commodity	Balance Sheet Location	Fair Value September 30, 2013	December 31, 2012
		(In thousands)	
Crude oil	Derivative instruments — current assets	$374	$19,016
Crude oil	Derivative instruments — non-current assets	3,405	4,981
Crude oil	Derivative instruments — current liabilities	(17,060)	(1,048)
Crude oil	Derivative instruments — non-current liabilities	(852)	(380)
Total derivative instruments		$(14,133)	$22,569

The following table summarizes the location and amounts of gains and losses from the Company's commodity derivative instruments for the periods presented:

	Income Statement Location	Three Months Ended September 30, 2013	2012	Nine Months Ended September 30, 2013	2012
		(In thousands)			
Change in fair value of derivative instruments	Net gain (loss) on derivative instruments	$(31,750)	$(27,690)	$(36,703)	$30,784
Derivative settlements	Net gain (loss) on derivative instruments	(8,067)	5,249	(5,135)	2,784
Total net gain (loss) on derivative instruments		$(39,817)	$(22,441)	$(41,838)	$33,568

The Company has adopted the FASB's authoritative guidance on disclosures about offsetting assets and liabilities, which requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the statement of financial position as well as instruments and transactions subject to an agreement similar to a master netting agreement. The Company's derivative instruments are presented as assets and liabilities on a net basis by counterparty, as all counterparty contracts provide for net settlement. No margin or collateral balances are deposited with counterparties, and as such, gross amounts are offset to determine the net amounts presented in the Company's Condensed Consolidated Balance Sheet.

The following tables summarize gross and net information about the Company's commodity derivative instruments for the periods presented:

Offsetting of Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
	(In thousands)		
As of September 30, 2013	$32,895	$ (29,116)	$ 3,779
As of December 31, 2012	68,970	(44,973)	23,997

Offsetting of Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet
	(In thousands)		
As of September 30, 2013	$47,028	$ (29,116)	$ 17,912
As of December 31, 2012	46,401	(44,973)	1,428

7. Long-Term Debt

Senior unsecured notes. On September 24, 2013, the Company issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the "2022 Notes"). The issuance of the 2022 Notes resulted in aggregate net proceeds to the

Company of approximately $983.0 million. The Company used the proceeds from the 2022 Notes to fund the acquisition of oil and gas properties in its West Williston project area (see Note 15 – Subsequent Events). The proceeds of the 2022 Notes were held in escrow as of September 30, 2013, pending the closing of the acquisition. The acquisition subsequently closed on October 1, 2013, at which time the funds were released from escrow.

Table of Contents

In connection with the issuance of the 2022 Notes, the Company and Guarantors (as defined below) entered into a Registration Rights Agreement pursuant to which the Company and Guarantors agreed to file a registration statement with the SEC to allow the holders of the 2022 Notes to exchange the 2022 Notes for the same principal amount of a new issue of notes with substantially identical terms, except the new notes will be freely transferable under the Securities Act. The Company and the Guarantors will use commercially reasonable efforts to cause the exchange to be completed within 360 days after the 2022 Notes issuance date. Under certain circumstances, in lieu of a registered exchange offer, the Company must use commercially reasonable efforts to file a shelf registration statement for the resale of the 2022 Notes. If the Company fails to satisfy these obligations on a timely basis, the annual interest borne by the 2022 Notes will be increased by 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective. The Company estimates the value of this contingent interest is immaterial at September 30, 2013.

During 2011 and 2012, the Company issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”), $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the “2021 Notes”) and $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes”, and together with the 2022 Notes, 2019 Notes and 2021 Notes, the “Notes”). The issuance of the 2019 Notes, 2021 Notes and the 2023 Notes resulted in aggregate net proceeds to the Company of approximately $1,175.8 million. The Company used the proceeds from the 2019 Notes, 2021 Notes and the 2023 Notes to fund its exploration, development and acquisition program and for general corporate purposes.

Interest on the Notes is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by the Company’s material subsidiaries (the “Guarantors”). These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions, as follows:

- in connection with any sale or other disposition of all or substantially all of the assets of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a restricted subsidiary of the Company;
- in connection with any sale or other disposition of the capital stock of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a restricted subsidiary of the Company, such that, immediately after giving effect to such transaction, such Guarantor would no longer constitute a subsidiary of the Company;
- if the Company designates any restricted subsidiary that is a Guarantor to be an unrestricted subsidiary in accordance with the indenture;
- upon legal defeasance or satisfaction and discharge of the indenture; or
- upon the liquidation or dissolution of a Guarantor, provided no event of default occurs under the indentures as a result thereof.

The Notes were issued under indentures containing provisions that are substantially the same, as amended and supplemented by supplemental indentures (collectively the “Indentures”), among the Company, the Guarantors and U.S. Bank National Association, as trustee (the “Trustee”). The Company has certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The Company estimates that the fair value of these redemption options is immaterial at September 30, 2013.

The Indentures restrict the Company’s ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to certain exceptions and qualifications. If at any time when the Notes are rated investment grade by both Moody’s Investors Service, Inc. and Standard & Poor’s Ratings Services and no Default (as defined in the Indentures) has occurred and is continuing, many of such covenants

will terminate and the Company and its subsidiaries will cease to be subject to such covenants.
The Indentures contain customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal or premium, if any, on any Note when due;

Table of Contents

- failure by the Company to comply with its other obligations under the Indentures, in certain cases subject to notice and grace periods;
- payment defaults and accelerations with respect to other indebtedness of the Company and its Restricted Subsidiaries (as defined in the Indentures) in the aggregate principal amount of $10.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indentures) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;
- failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $10.0 million within 60 days; and
- any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Senior secured revolving line of credit. On April 5, 2013, the Company, as parent, and OPNA, as borrower, entered into a second amended and restated credit agreement (the "Second Amended Credit Facility"), which has a maturity date of April 5, 2018. In connection with entry into the Second Amended Credit Facility, the semi-annual redetermination of the Company's borrowing base was also completed on April 5, 2013, which increased the borrowing base of the Second Amended Credit Facility from $750.0 million to $1,250.0 million. However, the Company elected to limit the aggregate commitment of the lenders under the Second Amended Credit Facility (the "Lenders") to $900.0 million. The Company could have increased its aggregate commitment to the full $1,250.0 million borrowing base by increasing the commitment of one or more lenders. In addition, under the Second Amended Credit Facility, the overall credit facility increased from $1,000.0 million to $2,500.0 million. On September 3, 2013, the Company entered into an amendment to its Second Amended Credit Facility (the "Amendment"). In connection with the Amendment, the lenders under the Company's revolving credit facility completed their regular semi-annual redetermination of the borrowing base scheduled for October 1, 2013. Following the redetermination, the Company's borrowing base increased from $1,250.0 million to $1,500.0 million and elected commitments also totaled $1,500.0 million.

The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. Borrowings under the Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.
Borrowings under the Second Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate ("LIBOR") loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or "ABR" loan). As of September 30, 2013, any outstanding LIBOR and ABR loans bore their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for LIBOR Loans	Applicable Margin for ABR Loans
Less than .25 to 1	1.50 %	0.00 %
Greater than or equal to .25 to 1 but less than .50 to 1	1.75 %	0.25 %
Greater than or equal to .50 to 1 but less than .75 to 1	2.00 %	0.50 %
Greater than or equal to .75 to 1 but less than .90 to 1	2.25 %	0.75 %
Greater than .90 to 1 but less than or equal 1	2.50 %	1.00 %

An ABR loan may be repaid at any time before the scheduled maturity of the Second Amended Credit Facility upon the Company providing advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the

Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms greater than three months in duration. At the end of a LIBOR loan term, the Second Amended Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company pays a 0.375% (as of September 30, 2013) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

As of September 30, 2013, the Second Amended Credit Facility contained covenants that included, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on the assets of the Company and its subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;
- a requirement that the Company maintain a ratio of consolidated EBITDAX (as defined in the Second Amended Credit Facility) to consolidated Interest Expense (as defined in the Second Amended Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that the Company maintain a Current Ratio (as defined in the Second Amended Credit Facility) of consolidated current assets (with exclusions as described in the Second Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Second Amended Credit Facility) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Second Amended Credit Facility contains customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under the Second Amended Credit Facility to be immediately due and payable.

As of September 30, 2013, the Company had $160.0 million of LIBOR loans and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base capacity of $1,334.8 million. The weighted average interest rate incurred on the outstanding Second Amended Credit Facility borrowings for both the three and nine months ended September 30, 2013 was 2.8%. The Company was in compliance with the financial covenants of the Second Amended Credit Facility as of September 30, 2013.

Deferred financing costs. As of September 30, 2013, the Company had $42.3 million of deferred financing costs related to the Notes and the Second Amended Credit Facility. The deferred financing costs are included in deferred costs and other assets on the Company's Condensed Consolidated Balance Sheet at September 30, 2013 and are being amortized over the respective terms of the Notes and the Second Amended Credit Facility. Amortization of deferred financing costs recorded for the three and nine months ended September 30, 2013 was $1.0 million and $2.9 million, respectively, and $0.8 million and $2.1 million for the three and nine months ended September 30, 2012, respectively. These costs are included in interest expense on the Company's Condensed Consolidated Statement of Operations.

8. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the nine months ended September 30, 2013:

	(In thousands)
Balance at December 31, 2012	$23,234
Liabilities incurred during period	3,066
Liabilities settled during period	23
Accretion expense during period (1)	895
Revisions to estimates	213
Balance at September 30, 2013	$27,431

(1) Included in depreciation, depletion and amortization on the Company's Condensed Consolidated Statement of Operations.

13

Table of Contents

At September 30, 2013, the current portion of the total ARO balance was approximately $0.4 million and is included in accrued liabilities on the Company's Condensed Consolidated Balance Sheet.

9. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its 2010 Long-Term Incentive Plan, the majority of which vest over a three-year period. 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. Beginning January 1, 2013, the Company assumed annual forfeiture rates by employee group ranging from 0% to 11% based on the Company's forfeiture history for this type of award as adjusted for management's expectations of forfeitures.

Stock-based compensation expense recorded for restricted stock awards for the three and nine months ended September 30, 2013 was $2.6 million and $7.1 million, respectively. For the three and nine months ended September 30, 2012, stock-based compensation expense recorded for restricted stock awards was $2.6 million and $6.5 million, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

Performance share units. The Company has granted performance share units ("PSUs") to officers of the Company under its 2010 Long-Term Incentive Plan. The PSUs are awards of restricted stock units, and each PSU that is earned represents the right to receive one share of the Company's common stock.

Each grant of PSUs is subject to a designated three-year initial performance period. The number of PSUs to be earned is subject to a market condition, which is based on a comparison of the total shareholder return ("TSR") achieved with respect to shares of the Company's common stock against the TSR achieved by a defined peer group at the end of the performance period. Depending on the Company's performance relative to the defined peer group, an award recipient will earn between 0% and 200% of the initial PSUs granted. If less than 200% of the initial PSUs granted are earned at the end of the initial performance period, then the performance period will be extended an additional year to give the recipient the opportunity to earn up to an aggregate of 200% of the initial PSUs granted.

The following table summarizes PSUs held by the Company's officers at September 30, 2013:

	PSUs		Weighted Average Grant Date Fair Value per Unit
Non-vested PSUs at December 31, 2012	155,220		$ 26.22
Granted	135,620		42.01
Vested	—		—
Forfeited	(21,540	)	32.89
Non-vested PSUs at September 30, 2013	269,300		$ 33.64

The Company accounted for these PSUs as equity awards pursuant to the FASB's authoritative guidance for share-based payments. The aggregate grant date fair value of the market-based awards was determined using a Monte Carlo simulation model, which results in an expected percentage of PSUs earned. The fair value of these PSUs is recognized on a straight-line basis over the performance period. As it is probable that a portion of the awards will be earned during the extended performance period, the grant date fair value will be amortized over four years. However, if 200% of the initial PSUs granted are earned at the end of the initial performance period, then the remaining compensation expense will be accelerated in order to be fully recognized over three years. All compensation expense related to the PSUs will be recognized if the requisite performance period is fulfilled, even if the market condition is not achieved.

The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions for the Monte Carlo model are the forecast period, initial value, risk-free rate, volatility and correlation coefficients. The risk-free rate is the U.S. treasury rate on the date of grant. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage in stock price over a historical two-year period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data. Beginning January 1, 2013, the Company assumed an annual forfeiture rate of 2.7% based on management's expectations of forfeitures for all PSUs granted.

Table of Contents

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the PSUs granted:

	2013 Grants	2012 Grants
Forecast period (years)	4.00	4.01
Risk-free rate	0.65%	0.46%
Oasis volatility	47.48%	51.00%

Based on these assumptions, the Monte Carlo simulation model resulted in an expected percentage of PSUs earned of 112% and 98% for the 2013 and 2012 grants, respectively. Stock-based compensation expense recorded for PSUs for the three and nine months ended September 30, 2013 was $0.5 million and $1.3 million, respectively, and is included in general and administrative expenses on the Condensed Consolidated Statement of Operations. Stock-based compensation expense recorded for PSUs for both the three and nine months ended September 30, 2012 was $0.2 million.

10. Income Taxes

The Company's effective tax rate for the three and nine months ended September 30, 2013 was 38.2% and 37.2%, respectively. The Company's effective tax rate for the three and nine months ended September 30, 2012 was 38.5% and 37.6%, respectively. These rates were consistent with the statutory tax rate applicable to the U.S. and the blended state rate for the states in which the Company conducts business. As of September 30, 2013, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

The Company had deferred tax assets for its federal and state tax loss carryforwards at September 30, 2013 recorded in current deferred taxes. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of September 30, 2013, management determined that a valuation allowance was not required for the tax loss carryforwards as they are expected to be fully utilized before expiration.

11. Earnings Per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings per share includes the impact of potentially dilutive non-vested restricted shares outstanding during the periods presented, unless their effect is anti-dilutive. There are no adjustments made to income available to common stockholders in the calculation of diluted earnings per share.

The following is a calculation of the basic and diluted weighted-average shares outstanding for the three and nine months ended September 30, 2013 and 2012:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(In thousands)			
Basic weighted average common shares outstanding	92,449	92,186	92,408	92,164
Dilution effect of stock awards at end of period	387	230	430	179
Diluted weighted average common shares outstanding	92,836	92,416	92,838	92,343
Anti-dilutive stock-based compensation awards	789	748	719	541

12. Business Segment Information

Table of Contents

In the first quarter of 2012, the Company began its well services business segment (OWS) to perform completion services for the Company's oil and natural gas wells operated by OPNA. Revenues for the well services segment are derived from providing well completion services and related product sales. In the first quarter of 2013, the Company formed its midstream services business segment (OMS) to perform salt water disposal and other midstream services for the Company's oil and natural gas wells operated by OPNA. Revenues for the midstream segment are primarily derived from providing salt water disposal services. Prior to 2013, the salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. The revenues and expenses related to work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation, and only the revenues and expenses related to non-affiliated working interest owners are included in the Company's Condensed Consolidated Statement of Operations. Prior to 2012, the Company only operated its exploration and production segment. The exploration and production segment is engaged in the acquisition and development of oil and natural gas properties and includes the complementary marketing services provided by OPM. Revenues for the exploration and production segment are primarily derived from the sale of oil and natural gas production. These segments represent the Company's three current operating units, each offering different products and services. The Company's corporate activities have been allocated to the supported business segments accordingly.
Management evaluates the performance of the Company's business segments based on operating income, which is defined as segment operating revenues less expenses. Summarized financial information for the Company's segments is shown in the following table:

	Exploration and Production (In thousands)	Well Services	Midstream Services	Consolidated
Three Months Ended September 30, 2013:				
Revenues	$286,952	$57,116	$7,597	$351,665
Inter-segment revenues	—	(40,026)	(6,141)	(46,167)
Total revenues	286,952	17,090	1,456	305,498
Operating income	140,765	5,870	4,227	150,862
Other income (expense)	(62,628)	(20)	—	(62,648)
Income before income taxes	78,137	5,850	4,227	88,214
Three Months Ended September 30, 2012:				
Revenues	$178,748	$37,160	$—	$215,908
Inter-segment revenues	—	(31,197)	—	(31,197)
Total revenues	178,748	5,963	—	184,711
Operating income (loss)	89,279	(17,241)	—	72,038
Other income (expense)	(42,273)	—	—	(42,273)
Income (loss) before income taxes	47,006	(17,241)	—	29,765
Nine Months Ended September 30, 2013:				
Revenues	$770,445	$124,266	$19,451	$914,162
Inter-segment revenues	—	(90,000)	(15,778)	(105,778)
Total revenues	770,445	34,266	3,673	808,384
Operating income	359,121	11,744	11,400	382,265
Other income (expense)	(106,159)	(11)	—	(106,170)
Income before income taxes	252,962	11,733	11,400	276,095
Nine Months Ended September 30, 2012:				
Revenues	$461,857	$54,909	$—	$516,766
Inter-segment revenues	—	(44,425)	—	(44,425)
Total revenues	461,857	10,484	—	472,341
Operating income	190,257	116	—	190,373
Other income (expense)	(12,863)	—	—	(12,863)

Income before income taxes	177,394	116	—	177,510
Total Assets:				
As of September 30, 2013	$3,916,554	$68,869	$97,960	$4,083,383
As of December 31, 2012	2,475,820	52,974	—	2,528,794

13. Commitments and Contingencies

Table of Contents

Lease obligations. The Company's total rental commitments under leases for office space and other property and equipment at September 30, 2013 were $11.5 million.

Drilling contracts. As of September 30, 2013, the Company had certain drilling rig contracts with initial terms greater than one year. In the event of early contract termination under these contracts, the Company would be obligated to pay approximately $24.9 million as of September 30, 2013 for the days remaining through the end of the primary terms of the contracts.

Volume commitment agreements. As of September 30, 2013, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 14.3 MMBbl and 12.8 Bcf from its Williston Basin project areas within specified timeframes, all of which are less than six years. Future obligations under these agreements were approximately $55.5 million as of September 30, 2013.

Investment commitment. As of September 30, 2013, the Company had a remaining capital commitment to invest, expend and/or incur expenses of $7.2 million in connection with drilling and completion activities for certain wells located in the Company's East Nesson project area, in exchange for the transfer of assets in connection with the East Nesson Acquisitions.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. The Company believes all such matters are without merit and involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows.

14. Condensed Consolidating Financial Information

The Notes (see Note 7) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company's immaterial wholly owned subsidiaries do not guarantee the Notes ("Non-Guarantor Subsidiaries").

The following financial information reflects consolidating financial information of the Company ("Issuer") and its Guarantors on a combined basis, prepared on the equity basis of accounting. The Non-Guarantor Subsidiaries are immaterial and, therefore, not presented separately. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantors operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantors because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantors.

Condensed Consolidating Balance Sheet
(In thousands, except share data)

	September 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$32,955	$92,485	$—	$125,440
Restricted cash	986,210	—	—	986,210
Accounts receivable – oil and gas revenues	—	155,068	—	155,068
Accounts receivable – joint interest partners	—	120,058	—	120,058
Accounts receivable – from affiliates	770	8,432	(9,202)	—
Inventory	—	18,358	—	18,358
Prepaid expenses	477	6,963	—	7,440
Advances to joint interest partners	—	1,170	—	1,170

Derivative instruments	—	374	—	374
Deferred income taxes	—	8,683	—	8,683
Other current assets	2	471	—	473
Total current assets	1,020,414	412,062	(9,202)	1,423,274
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	3,044,515	—	3,044,515
Other property and equipment	—	157,926	—	157,926
Less: accumulated depreciation, depletion, amortization and impairment	—	(589,173)	—	(589,173)
Total property, plant and equipment, net	—	2,613,268	—	2,613,268
Investments in and advances to subsidiaries	2,082,828	—	(2,082,828)	—
Derivative instruments	—	3,405	—	3,405
Deferred income taxes	69,795	—	(69,795)	—
Deferred costs and other assets	34,128	9,308	—	43,436
Total assets	$3,207,165	$3,038,043	$(2,161,825)	$4,083,383
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable	$—	$39,468	$—	$39,468
Accounts payable – from affiliates	8,432	770	(9,202)	—
Advances from joint interest partners	—	13,211	—	13,211
Revenues and production taxes payable	—	133,083	—	133,083
Accrued liabilities	46	198,447	—	198,493
Accrued interest payable	22,809	64	—	22,873
Derivative instruments	—	17,060	—	17,060
Total current liabilities	31,287	402,103	(9,202)	424,188
Long-term debt	2,200,000	160,000	—	2,360,000
Asset retirement obligations	—	26,999	—	26,999
Derivative instruments	—	852	—	852
Deferred income taxes	—	362,951	(69,795)	293,156
Other liabilities	—	2,310	—	2,310
Total liabilities	2,231,287	955,215	(78,997)	3,107,505
Stockholders' equity				
Capital contributions from affiliates	—	1,643,729	(1,643,729)	—
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,854,867 issued and 93,690,494 outstanding	926	—	—	926
Treasury stock, at cost; 164,373 shares	(5,220)	—	—	(5,220)
Additional paid-in-capital	666,770	8,743	(8,743)	666,770
Retained earnings	313,402	430,356	(430,356)	313,402
Total stockholders' equity	975,878	2,082,828	(2,082,828)	975,878
Total liabilities and stockholders' equity	$3,207,165	$3,038,043	$(2,161,825)	$4,083,383

Table of Contents

Condensed Consolidating Balance Sheet
(In thousands, except share data)

	December 31, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$133,797	$79,650	$—	$213,447
Short-term investments	25,891	—	—	25,891
Accounts receivable – oil and gas revenues	—	110,341	—	110,341
Accounts receivable – joint interest partners	—	99,194	—	99,194
Accounts receivable – from affiliates	310	5,845	(6,155)	—
Inventory	—	20,707	—	20,707
Prepaid expenses	313	1,457	—	1,770
Advances to joint interest partners	—	1,985	—	1,985
Derivative instruments	—	19,016	—	19,016
Other current assets	235	100	—	335
Total current assets	160,546	338,295	(6,155)	492,686
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	2,348,128	—	2,348,128
Other property and equipment	—	49,732	—	49,732
Less: accumulated depreciation, depletion, amortization and impairment	—	(391,260)	—	(391,260)
Total property, plant and equipment, net	—	2,006,600	—	2,006,600
Investments in and advances to subsidiaries	1,807,010	—	(1,807,010)	—
Derivative instruments	—	4,981	—	4,981
Deferred income taxes	42,746	—	(42,746)	—
Deferred costs and other assets	20,748	3,779	—	24,527
Total assets	$2,031,050	$2,353,655	$(1,855,911)	$2,528,794
LIABILITIES AND STOCKHOLDERS’ EQUITY				
Current liabilities				
Accounts payable	$9	$12,482	$—	$12,491
Accounts payable – from affiliates	5,845	310	(6,155)	—
Advances from joint interest partners	—	21,176	—	21,176
Revenues and production taxes payable	—	71,553	—	71,553
Accrued liabilities	100	189,763	—	189,863
Accrued interest payable	30,091	5	—	30,096
Derivative instruments	—	1,048	—	1,048
Deferred income taxes	—	4,558	—	4,558
Total current liabilities	36,045	300,895	(6,155)	330,785
Long-term debt	1,200,000	—	—	1,200,000
Asset retirement obligations	—	22,956	—	22,956
Derivative instruments	—	380	—	380
Deferred income taxes	—	220,417	(42,746)	177,671
Other liabilities	—	1,997	—	1,997
Total liabilities	1,236,045	546,645	(48,901)	1,733,789
Stockholders’ equity				

Capital contributions from affiliates	—	1,586,780	(1,586,780)	—
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,432,712 issued and 93,303,298 outstanding	925	—	—	925
Treasury stock, at cost; 129,414 shares	(3,796)	—	—	(3,796)
Additional paid-in-capital	657,943	8,743	(8,743)	657,943
Retained earnings	139,933	211,487	(211,487)	139,933
Total stockholders' equity	795,005	1,807,010	(1,807,010)	795,005
Total liabilities and stockholders' equity	$2,031,050	$2,353,655	$(1,855,911)	$2,528,794

Condensed Consolidating Statement of Operations
(In thousands)

	Three Months Ended September 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$286,952	$—	$286,952
Well services and midstream revenues	—	18,546	—	18,546
Total revenues	—	305,498	—	305,498
Expenses				
Lease operating expenses	—	21,831	—	21,831
Well services and midstream operating expenses	—	10,319	—	10,319
Marketing, transportation and gathering expenses	—	5,688	—	5,688
Production taxes	—	26,823	—	26,823
Depreciation, depletion and amortization	—	72,728	—	72,728
Exploration expenses	—	463	—	463
Impairment of oil and gas properties	—	56	—	56
General and administrative expenses	3,746	12,982	—	16,728
Total expenses	3,746	150,890	—	154,636
Operating income (loss)	(3,746)	154,608	—	150,862
Other income (expense)				
Equity in earnings in subsidiaries	70,118	—	(70,118)	—
Net loss on derivative instruments	—	(39,817)	—	(39,817)
Interest expense, net of capitalized interest	(21,277)	(1,577)	—	(22,854)
Other income	15	8	—	23
Total other income (expense)	48,856	(41,386)	(70,118)	(62,648)
Income before income taxes	45,110	113,222	(70,118)	88,214
Income tax benefit (expense)	9,389	(43,104)	—	(33,715)
Net income	$54,499	$70,118	$(70,118)	$54,499

Condensed Consolidating Statement of Operations
(In thousands)

	Three Months Ended September 30, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$178,748	$—	$178,748
Well services revenues	—	5,963	—	5,963
Total revenues	—	184,711	—	184,711
Expenses				
Lease operating expenses	—	16,134	—	16,134
Well services operating expenses	—	5,420	—	5,420
Marketing, transportation and gathering expenses	—	2,744	—	2,744
Production taxes	—	16,433	—	16,433
Depreciation, depletion and amortization	—	57,684	—	57,684

Exploration expenses	—	336	—	336
Impairment of oil and gas properties	—	36	—	36
General and administrative expenses	2,988	10,898	—	13,886
Total expenses	2,988	109,685	—	112,673
Operating income (loss)	(2,988)	75,026	—	72,038
Other income (expense)				
Equity in earnings in subsidiaries	32,735	—	(32,735)	—
Net loss on derivative instruments	—	(22,441)	—	(22,441)
Interest expense, net of capitalized interest	(20,307)	(672)	—	(20,979)
Other income	238	909	—	1,147
Total other income (expense)	12,666	(22,204)	(32,735)	(42,273)
Income before income taxes	9,678	52,822	(32,735)	29,765
Income tax benefit (expense)	8,636	(20,087)	—	(11,451)
Net income	$18,314	$32,735	$(32,735)	$18,314

Condensed Consolidating Statement of Operations
(In thousands)

	Nine Months Ended September 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$770,445	$—	$770,445
Well services and midstream revenues	—	37,939	—	37,939
Total revenues	—	808,384	—	808,384
Expenses				
Lease operating expenses	—	59,586	—	59,586
Well services and midstream operating expenses	—	19,877	—	19,877
Marketing, transportation and gathering expenses	—	19,856	—	19,856
Production taxes	—	70,309	—	70,309
Depreciation, depletion and amortization	—	205,779	—	205,779
Exploration expenses	—	2,712	—	2,712
Impairment of oil and gas properties	—	762	—	762
General and administrative expenses	10,146	37,092	—	47,238
Total expenses	10,146	415,973	—	426,119
Operating income (loss)	(10,146)	392,411	—	382,265
Other income (expense)				
Equity in earnings in subsidiaries	218,869	—	(218,869)	—
Net loss on derivative instruments	—	(41,838)	—	(41,838)
Interest expense, net of capitalized interest	(61,955)	(3,474)	—	(65,429)
Other income	(348)	1,445	—	1,097
Total other income (expense)	156,566	(43,867)	(218,869)	(106,170)
Income before income taxes	146,420	348,544	(218,869)	276,095
Income tax benefit (expense)	27,049	(129,675)	—	(102,626)
Net income	$173,469	$218,869	$(218,869)	$173,469

Condensed Consolidating Statement of Operations
(In thousands)

Nine Months Ended September 30, 2012

	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$461,857	$—	$461,857
Well services and midstream revenues	—	10,484	—	10,484
Total revenues	—	472,341	—	472,341
Expenses				
Lease operating expenses	—	37,979	—	37,979
Well services and midstream operating expenses	—	7,104	—	7,104
Marketing, transportation and gathering expenses	—	7,283	—	7,283
Production taxes	—	43,419	—	43,419
Depreciation, depletion and amortization	—	140,783	—	140,783
Exploration expenses	—	3,171	—	3,171
Impairment of oil and gas properties	—	2,607	—	2,607
General and administrative expenses	8,078	31,544	—	39,622
Total expenses	8,078	273,890	—	281,968
Operating income (loss)	(8,078)	198,451	—	190,373
Other income (expense)				
Equity in earnings in subsidiaries	145,021	—	(145,021)	—
Net gain on derivative instruments	—	33,568	—	33,568
Interest expense, net of capitalized interest	(47,136)	(1,816)	—	(48,952)
Other income	533	1,988	—	2,521
Total other income (expense)	98,418	33,740	(145,021)	(12,863)
Income before income taxes	90,340	232,191	(145,021)	177,510
Income tax benefit (expense)	20,458	(87,170)	—	(66,712)
Net income	$110,798	$145,021	$(145,021)	$110,798

19

Table of Contents

Condensed Consolidating Statement of Cash Flows
(In thousands)

	Nine Months Ended September 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$173,469	$218,869	$(218,869)	$173,469
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(218,869)	—	218,869	—
Depreciation, depletion and amortization	—	205,779	—	205,779
Impairment of oil and gas properties	—	762	—	762
Deferred income taxes	(27,049)	129,293	—	102,244
Derivative instruments	—	41,838	—	41,838
Stock-based compensation expenses	8,196	215	—	8,411
Debt discount amortization and other	2,850	(157)	—	2,693
Working capital and other changes:				
Change in accounts receivable	(460)	(69,614)	2,587	(67,487)
Change in inventory	—	(8,820)	—	(8,820)
Change in prepaid expenses	(164)	(5,011)	—	(5,175)
Change in other current assets	233	(371)	—	(138)
Change in other assets	—	(63)	—	(63)
Change in accounts payable and accrued liabilities	(4,758)	89,591	(2,587)	82,246
Change in other current liabilities	—	—	—	—
Change in other liabilities	—	922	—	922
Net cash provided by (used in) operating activities	(66,552)	603,233	—	536,681
Cash flows from investing activities:				
Capital expenditures	—	(654,175)	—	(654,175)
Acquisitions of oil and gas properties	—	(133,061)	—	(133,061)
Increase in restricted cash	(986,210)	—	—	(986,210)
Derivative settlements	—	(5,135)	—	(5,135)
Redemptions of short-term investments	25,000	—	—	25,000
Advances from joint interest partners	—	(7,965)	—	(7,965)
Net cash used in investing activities	(961,210)	(800,336)	—	(1,761,546)
Cash flows from financing activities:				
Proceeds from credit facility	—	160,000	—	160,000
Proceeds from issuance of senior notes	1,000,000	—	—	1,000,000
Purchases of treasury stock	(1,424)	—	—	(1,424)
Debt issuance costs	(15,340)	(6,378)	—	(21,718)
Investment in / capital contributions from affiliates	(56,316)	56,316	—	—
Net cash provided by financing activities	926,920	209,938	—	1,136,858
Increase (decrease) in cash and cash equivalents	(100,842)	12,835	—	(88,007)
Cash and cash equivalents at beginning of period	133,797	79,650	—	213,447
Cash and cash equivalents at end of period	$32,955	$92,485	$—	$125,440

Condensed Consolidating Statement of Cash Flows

(In thousands)

	Nine Months Ended September 30, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$110,798	$145,021	$(145,021)	$110,798
Adjustments to reconcile net income to net cash provided by operating activities:				
Equity in earnings of subsidiaries	(145,021)	—	145,021	—
Depreciation, depletion and amortization	—	140,783	—	140,783
Impairment of oil and gas properties	—	2,607	—	2,607
Deferred income taxes	(20,458)	87,106	—	66,648
Derivative instruments	—	(33,568)	—	(33,568)
Stock-based compensation expenses	6,397	230	—	6,627
Debt discount amortization and other	1,616	422	—	2,038
Working capital and other changes:				
Change in accounts receivable	(203)	(70,899)	1,939	(69,163)
Change in inventory	—	(26,790)	—	(26,790)
Change in prepaid expenses	(192)	(1,817)	—	(2,009)
Change in other current assets	(60)	473	—	413
Change in other assets	(24)	(95)	—	(119)
Change in accounts payable and accrued liabilities	8,620	72,398	(1,939)	79,079
Change in other current liabilities	—	4,784	—	4,784
Net cash provided by operating activities	(38,527)	320,655	—	282,128
Cash flows from investing activities:				
Capital expenditures	—	(777,516)	—	(777,516)
Derivative settlements	—	2,784	—	2,784
Purchases of short-term investments	(126,213)	—	—	(126,213)
Redemptions of short-term investments	19,994	—	—	19,994
Advances from joint interest partners	—	17,508	—	17,508
Net cash used in investing activities	(106,219)	(757,224)	—	(863,443)
Cash flows from financing activities:				
Proceeds from issuance of senior notes	400,000	—		400,000
Purchases of treasury stock	(1,299)	—	—	(1,299)
Debt issuance costs	(7,255)	(700)	—	(7,955)
Investment in / capital contributions from affiliates	(459,012)	459,012	—	—
Net cash provided by (used in) financing activities	(67,566)	458,312	—	390,746
Increase (decrease) in cash and cash equivalents	(212,312)	21,743	—	(190,569)
Cash and cash equivalents at beginning of period	443,482	27,390	—	470,872
Cash and cash equivalents at end of period	$231,170	$49,133	$—	$280,303

15. Subsequent Events

The Company has evaluated the period after the balance sheet date, noting no subsequent events or transactions that required recognition or disclosure in the financial statements, other than as noted below.

West Williston acquisition. On October 1, 2013, the Company acquired approximately 136,000 net acres in and around its position in North Dakota in its West Williston project area (the “West Williston Acquisition”) for $1,478.6 million, which included a $72.5 million deposit made in September 2013, and is subject to further customary post close adjustments. The Company funded the West Williston Acquisition with proceeds from its issuance of the 2022 Notes and borrowings under its

20

Table of Contents

revolving credit facility (see below and Note 7 – Long-Term Debt). The West Williston Acquisition will be accounted for as a business combination.

Senior secured revolving line of credit. On October 1, 2013, the Company borrowed an additional $440.0 million under its Second Amended Credit Facility, resulting in total outstanding indebtedness under the Second Amended Credit Facility of $605.2 million and an unused borrowing base capacity of $894.8 million. After the closing of the 2022 Notes and the West Williston Acquisition, the Lenders kept the borrowing base of the Second Amended Credit Facility at $1,500.0 million.

Drilling contracts. In October 2013, the Company assumed an additional long-term drilling rig contract as part of the West Williston Acquisition. In the event of early termination under this contract, the Company would be obligated to pay an additional maximum amount of approximately $9.7 million if terminated immediately after execution.

Purchase agreements. In October 2013, the Company entered into an agreement to purchase well fracturing equipment. The future obligation under this agreement is $3.6 million.

Table of Contents

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10-K for the year ended December 31, 2012 ("2012 Annual Report"), as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. 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 included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report on Form 10-Q, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed under Item 1A. "Risk Factors" in our 2012 Annual Report 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;
- our financial strategy, budget, projections, execution of business plan and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating well services and midstream companies;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- integration and benefits of property acquisitions, including our recent acquisitions of oil and gas properties in our West Williston and East Nesson project areas, or the effects of such acquisitions on our cash position and levels of indebtedness;
- property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- drilling and completion of wells;
- estimated inventory of wells remaining to be drilled and completed;
- infrastructure for salt water disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- general economic conditions;
- operating environment, including inclement weather conditions;
- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;

- uncertainty regarding future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report on Form 10-Q are reasonable, we can give no assurance that

Table of Contents

these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Quarterly Report on Form 10-Q, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Overview

We are an independent exploration and production ("E&P") company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the Montana and North Dakota regions of the Williston Basin. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity is primarily directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. Oasis Petroleum North America LLC ("OPNA") conducts our domestic oil and natural gas E&P activities. We also operate a marketing business, Oasis Petroleum Marketing LLC ("OPM"), a well services business, Oasis Well Services LLC ("OWS"), and a midstream services business, Oasis Midstream Services LLC ("OMS"), which are all complementary to our primary development and production activities. OWS and OMS are separate reportable business segments. The revenues and expenses related to work performed by OPM, OWS and OMS for OPNA's working interests are eliminated in consolidation and, therefore, do not directly contribute to our consolidated results of operations.

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, the acquisition of non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

Due to the geographic concentration of our oil and natural gas properties in the Williston Basin, we believe the primary sources of opportunities, challenges and risks related to our business for both the short and long-term are:

- Commodity prices for oil and natural gas;
- Transportation capacity;
- Availability and cost of services; and
- Availability of qualified personnel.

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, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk, and enter into physical delivery contracts to manage our price differentials. In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, we sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of September 30, 2013, we were flowing approximately 85% of our gross operated oil production through these gathering systems.

Table of Contents

Changes in commodity prices may also significantly affect the economic viability of drilling projects and economic recovery of oil and gas reserves. As a result of higher commodity prices and continued successes in the application of completion technologies in the Bakken formation, there were approximately 188 active drilling rigs in the Williston Basin at September 30, 2013. Both production and takeaway capacity have grown rapidly in the Williston Basin throughout 2012 and 2013. In the first half of 2012, price differentials were at or above the historical average discount range of 10% to 15% to the price quoted for NYMEX West Texas Intermediate ("WTI") crude oil due to production growth in the Williston Basin combined with refinery and transportation constraints. In the third quarter of 2012, our price differentials relative to WTI began to narrow, primarily due to transportation capacity additions, including expanded rail infrastructure and pipeline expansions, outpacing production growth. In the fourth quarter of 2012 and into the first quarter of 2013, average price differentials continued to narrow, primarily due to our ability to access premium coastal markets by rail. As the premium at coastal markets contracted during the second and third quarters of 2013, our price differentials relative to WTI increased. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations.

Third Quarter 2013 Highlights:

- We completed and placed on production 38 gross (27.7 net) operated wells in the Williston Basin during the three months ended September 30, 2013;
- We had 37 gross operated wells awaiting completion and 9 gross operated wells in the process of being drilled in the Bakken and Three Forks formations at September 30, 2013;
- Average daily production was 33,064 Boe per day during the three months ended September 30, 2013;
- E&P capital expenditures were $370.9 million, consisting primarily of $224.2 million in drilling and completion expenditures and $127.7 million for the acquisition of oil and gas properties during the three months ended September 30, 2013; and
- At September 30, 2013, we had $125.4 million of cash and cash equivalents, and $160.0 million of outstanding borrowings and $5.2 million of outstanding letters of credit under our revolving credit facility.
- Executed four separate purchase and sale agreements to acquire approximately 161,000 net acres in the Williston Basin, all of which have closed as of October 1, 2013.
- Issued $1,000.0 million in senior notes due in 2022 and increased borrowing base to $1,500.0 million.

Results of Operations

Revenues

Our oil and gas revenues are derived from the sale of oil and natural gas production. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Our well services and midstream revenues are primarily derived from well completion activity and salt water disposal for third-party working interest owners in OPNA's operated wells.

The following table summarizes our revenues and production data for the periods presented:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	Change	2013	2012	Change
Operating results (in thousands):						
Revenues						
Oil	$273,663	$173,752	$99,911	$737,963	$443,686	$294,277
Natural gas	13,289	4,996	8,293	32,482	18,171	14,311
Well services and midstream	18,546	5,963	12,583	37,939	10,484	27,455
Total revenues	305,498	184,711	120,787	808,384	472,341	336,043
Production data:						
Oil (MBbls)	2,716	2,076	640	7,687	5,232	2,455
Natural gas (MMcf)	1,954	937	1,017	4,883	2,740	2,143
Oil equivalents (MBoe)	3,042	2,232	810	8,501	5,688	2,813
Average daily production (Boe/d)	33,064	24,257	8,807	31,140	20,761	10,379
Average sales prices:						
Oil, without derivative settlements (per Bbl) (1)	$100.75	$83.71	$17.04	$95.24	$84.52	$10.72
Oil, with derivative settlements (per Bbl) (1) (2)	97.78	86.24	11.54	94.58	85.05	9.53
Natural gas (per Mcf) (3)	6.80	5.33	1.47	6.65	6.63	0.02

(1) Average sales prices for oil are calculated using total oil revenues, excluding bulk oil sales, divided by oil production. Bulk oil sales totaled $5.8 million for the nine months ended September 30, 2013 and $1.5 million for the nine months ended September 30, 2012.

(2) Realized prices include gains or losses on cash settlements for commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes.

(3) Natural gas prices include the value for natural gas and natural gas liquids.

Three months ended September 30, 2013 as compared to three months ended September 30, 2012

Total revenues. Our total revenues increased $120.8 million, or 65%, to $305.5 million during the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 8,807 Boe per day, or 36%, to 33,064 Boe per day during the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. The increase in average daily production sold was primarily a result of our well completions during the twelve months ended September 30, 2013, offsetting the decline in production in wells that were producing as of September 30, 2012. Average daily production in our East Nesson, West Williston and Sanish project areas increased by approximately 5,707 Boe per day, 2,654 Boe per day and 446 Boe per day, respectively, during the third quarter of 2013 as compared to the third quarter of 2012. Average oil sales prices, without derivative settlements, increased by $17.04/Bbl to an average of $100.75/Bbl for the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. The higher production amounts sold increased revenues by $71.5 million, while higher oil and natural gas prices increased revenues by $36.7 million during the three months ended September 30, 2013 compared to the three months ended September 30, 2012.

Well services revenues increased $11.1 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012 due to an increase in well completion activity and related product sales. Midstream revenues totaled $1.5 million for the three months ended September 30, 2013. There were no midstream revenues during the third quarter of 2012 because OMS did not commence activity until the first quarter of 2013. Prior to 2013, the salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA’s operated wells only, as work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation.

Nine months ended September 30, 2013 as compared to nine months ended September 30, 2012

Total revenues. Our total revenues increased $336.0 million, or 71%, to $808.4 million during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 10,379 Boe per day, or 50%, to 31,140 Boe per day during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. The increase in average daily production sold was primarily a result of our well completions during the twelve months ended September 30, 2013, offsetting the decline in production in wells that

Table of Contents

were producing as of September 30, 2012. Average daily production in our East Nesson, West Williston and Sanish project areas increased by approximately 5,154 Boe per day, 4,668 Boe per day and 557 Boe per day, respectively, during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. Average oil sales prices, without derivative settlements, increased by $10.72/Bbl to an average of $95.24/Bbl for the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. The higher production amounts sold increased revenues by $248.1 million, while higher oil and natural gas prices increased revenues by $56.2 million during the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. In addition, bulk oil sales related to marketing activities included in oil revenues increased $4.3 million during the nine months ended September 30, 2013 as compared to the nine months ended September 30, 2012. Well services revenues increased $23.8 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 due to an increase in well completion activity and related product sales. Midstream revenues totaled $3.7 million for the nine months ended September 30, 2013. There were no midstream revenues during 2012 because OMS did not commence activity until the first quarter of 2013. Prior to 2013, the salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA's operated wells only, as work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation.

Expenses

The following table summarizes our operating expenses for the periods presented:

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2013	2012	$ Change	2013	2012	$ Change
Expenses:						
Lease operating expenses (1)	$21,831	$16,134	$5,697	$59,586	$37,979	$21,607
Well services and midstream operating expenses	10,319	5,420	4,899	19,877	7,104	12,773
Marketing, transportation and gathering expenses	5,688	2,744	2,944	19,856	7,283	12,573
Production taxes	26,823	16,433	10,390	70,309	43,419	26,890
Depreciation, depletion and amortization	72,728	57,684	15,044	205,779	140,783	64,996
Exploration expenses	463	336	127	2,712	3,171	(459)
Impairment of oil and gas properties	56	36	20	762	2,607	(1,845)
General and administrative expenses	16,728	13,886	2,842	47,238	39,622	7,616
Total expenses	154,636	112,673	41,963	426,119	281,968	144,151
Operating income	150,862	72,038	78,824	382,265	190,373	191,892
Other income (expense):						
Net gain (loss) on derivative instruments	(39,817)	(22,441)	(17,376)	(41,838)	33,568	(75,406)
Interest expense, net of capitalized interest	(22,854)	(20,979)	(1,875)	(65,429)	(48,952)	(16,477)
Other income	23	1,147	(1,124)	1,097	2,521	(1,424)
Total other income (expense)	(62,648)	(42,273)	(20,375)	(106,170)	(12,863)	(93,307)
Income before income taxes	88,214	29,765	58,449	276,095	177,510	98,585
Income tax expense	33,715	11,451	22,264	102,626	66,712	35,914
Net income	$54,499	$18,314	$36,185	$173,469	$110,798	$62,671
Cost and expense (per Boe of production):						
Lease operating expenses (1)	$7.18	$7.23	$(0.05)	$7.01	$6.68	$0.33
Marketing, transportation and gathering expenses	1.87	1.23	0.64	2.34	1.28	1.06
Production taxes	8.82	7.36	1.46	8.27	7.63	0.64

Depreciation, depletion and amortization	23.91	25.85	(1.94)	24.21	24.75	(0.54)
General and administrative expenses	5.50	6.22	(0.72)	5.56	6.97	(1.41)

(1) For the three and nine months ended September 30, 2012, lease operating expenses include midstream income and operating expenses, which are included in well services and midstream revenues and well services and midstream operating expenses, respectively, for the three and nine months ended September 30, 2013.

Three months ended September 30, 2013 compared to three months ended September 30, 2012

Table of Contents

Lease operating expenses. Lease operating expenses increased $5.7 million to $21.8 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our well completions, partially offset by lower costs for equipment rentals, hot oil treatments, chemical treatments and repairs during the three months ended September 30, 2013 as compared to the three months ended September 30, 2012. The formation of OMS in the first quarter of 2013 resulted in income related to midstream activity being included in well services and midstream revenues, rather than as a reduction to lease operating expenses. Lease operating expenses decreased from $7.23 per Boe for the three months ended September 30, 2012 to $7.18 per Boe for the three months ended September 30, 2013. Excluding the formation of OMS, lease operating expenses would have been $6.50 per Boe for the three months ended September 30, 2013.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and midstream operating expenses incurred by OMS. The $4.9 million increase for the three months ended September 30, 2013 compared to the three months ended September 30, 2012 was attributable to a $4.5 million increase from OWS' well completion activity and related product sales, and a $0.4 million increase related to midstream services operating expenses. There were no midstream services operating expenses during the third quarter of 2012 because OMS did not commence activity until the first quarter of 2013.

Marketing, transportation and gathering expenses. The $2.9 million increase for the three months ended September 30, 2013 compared to the three months ended September 30, 2012 was primarily attributable to higher operated volumes flowing through third-party gathering pipelines during the three months ended September 30, 2013. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the three months ended September 30, 2013 and 2012 were 9.4% and 9.2% respectively, as a percentage of oil and natural gas sales. The third quarter 2013 production tax rate was higher than the third quarter 2012 production tax rate primarily due to the decreased weighting of oil revenues on certain new wells in Montana that are subject to lower incentivized production tax rates.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $15.0 million to $72.7 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. This increase in DD&A expense for the three months ended September 30, 2013 was primarily a result of our production increases from our wells completed during the twelve months ended September 30, 2013. The DD&A rate for the three months ended September 30, 2013 was $23.91 per Boe compared to $25.85 per Boe for the three months ended September 30, 2012. The decrease in DD&A rate was a result of lower well costs for wells completed during the second half of 2012 and the first half of 2013.

Impairment of oil and gas properties. During the three months ended September 30, 2013 and 2012, we recorded non-cash impairment charges of $56,000 and $36,000, respectively, for expiring leases and periodic assessments of unproved properties. No impairment charges of proved oil and gas properties were recorded for the three months ended September 30, 2013 or 2012.

General and administrative ("G&A") expenses. Our G&A expenses increased $2.8 million for the three months ended September 30, 2013 from $13.9 million for the three months ended September 30, 2012. Of this increase, approximately $2.4 million related to increased employee compensation expense due to our organizational growth and $0.4 million was due to increased amortization of our restricted stock awards and performance share units quarter over quarter. As of September 30, 2013, we had 356 full-time employees compared to 259 full-time employees as of September 30, 2012.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net loss of $8.1 million for the three months ended September 30, 2013 and a cash settlement net gain of $5.2 million for the three months ended September 30, 2012. In addition, as a result of forward oil price changes, we recognized a $31.8 million and a $27.7 million non-cash mark-to-market net derivative loss during the three months ended September 30, 2013 and 2012, respectively.

Interest expense. Interest expense increased $1.9 million to $22.9 million for the three months ended September 30, 2013 compared to the three months ended September 30, 2012. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in September 2013 at an interest rate of 6.875% coupled with interest expense incurred on borrowings under our revolving credit facility during September 2013. Loans under our revolving credit facility were $160.0 million at September 30, 2013. There were no borrowings under our revolving credit facility during the three months ended September 30, 2012. Interest capitalized during the three months ended September 30, 2013 and 2012 was $1.4 million and $0.9 million, respectively.

Table of Contents

Income taxes. Income tax expense for the three months ended September 30, 2013 and 2012 was recorded at 38.2% and 38.5% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

Nine months ended September 30, 2013 compared to nine months ended September 30, 2012

Lease operating expenses. Lease operating expenses increased $21.6 million to $59.6 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our well completions. Additionally, the formation of OMS in the first quarter of 2013 resulted in income related to midstream activity being included in well services and midstream revenues, rather than as a reduction to lease operating expenses. Lease operating expenses increased from $6.68 per Boe for the nine months ended September 30, 2012 to $7.01 per Boe for the nine months ended September 30, 2013. Excluding the formation of OMS, lease operating expenses would have been $6.05 per Boe for the nine months ended September 30, 2013.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and midstream operating expenses incurred by OMS. The $12.8 million increase for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 was attributable to a $11.9 million increase from OWS' well completion activity and related product sales, and a $0.8 million increase related to midstream services operating expenses. There were no midstream services operating expenses during the first nine months of 2012 because OMS did not commence activity until the first quarter of 2013.

Marketing, transportation and gathering expenses. The $12.6 million increase for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012 was primarily attributable to a $7.7 million increase related to higher operated volumes flowing through third-party gathering pipelines and a $4.4 million increase in bulk oil purchases made by OPM. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the nine months ended September 30, 2013 and 2012 were 9.2% and 9.4%, respectively, as a percentage of oil and natural gas sales. The production tax rate for the nine months ended September 30, 2013 was lower than the production tax rate for the nine months ended September 30, 2012 primarily due to the increased weighting of oil revenues on certain new wells in Montana that are subject to lower incentivized production tax rates.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $65.0 million to $205.8 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. This increase in DD&A expense for the nine months ended September 30, 2013 was primarily a result of our production increases from our wells completed during the twelve months ended September 30, 2013. The DD&A rate for the nine months ended September 30, 2013 was $24.21 per Boe compared to $24.75 per Boe for the nine months ended September 30, 2012. The decrease in DD&A rate was a result of lower well costs for wells completed during the second half of 2012 and the first half of 2013.

Impairment of oil and gas properties. During the nine months ended September 30, 2013 and 2012, we recorded non-cash impairment charges of $0.8 million and $2.6 million, respectively, for expiring leases and periodic assessments of unproved properties. No impairment charges of proved oil and gas properties were recorded for the nine months ended September 30, 2013 or 2012.

General and administrative ("G&A") expenses. Our G&A expenses increased $7.6 million for the nine months ended September 30, 2013 from $39.6 million for the nine months ended September 30, 2012. Of this increase, approximately $8.2 million related to increased employee compensation expenses due to our organizational growth and $1.9 million was due to increased amortization of our restricted stock awards and performance share units period over period. As of September 30, 2013, we had 356 full-time employees compared to 259 full-time employees as of September 30, 2012. There were offsetting decreases of $0.9 million related to OWS and $1.0 million related to the formation of OMS during the nine months ended September 30, 2013.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net loss of $5.1 million for the nine months ended September 30, 2013 and a cash settlement net gain of $2.8 million for the nine months ended September 30, 2012. In addition, as a result of forward oil price changes, we recognized a $36.7 million non-cash mark-to-market net derivative loss during the nine months ended September 30, 2013 and a $30.8 million non-cash mark-to-market net derivative gain during the nine months ended September 30, 2012.

Table of Contents

Interest expense. Interest expense increased $16.5 million to $65.4 million for the nine months ended September 30, 2013 compared to the nine months ended September 30, 2012. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in July 2012 and September 2013 at an interest rate of 6.875% coupled with interest expense incurred on borrowings under our revolving credit facility during September 2013. Loans under our revolving credit facility were $160.0 million at September 30, 2013. There were no borrowings under our revolving credit facility during the nine months ended September 30 2012. Interest capitalized during the nine months ended September 30, 2013 and 2012 was $3.2 million and $2.5 million, respectively.

Income taxes. Income tax expense for the nine months ended September 30, 2013 and 2012 was recorded at 37.2% and 37.6% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report are proceeds from our senior unsecured notes, cash flows from operations and borrowings and availability under our revolving credit facility. Our primary use of capital has been for the development and acquisition of oil and natural gas properties. We continually monitor potential capital sources, including selling assets, equity financings, debt financings and other strategic alternatives, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Our cash flows for the nine months ended September 30, 2013 and 2012 are presented below:

	Nine Months Ended September 30,	
	2013	2012
	(In thousands)	
Net cash provided by operating activities	$536,681	$282,128
Net cash used in investing activities	(1,761,546)	(863,443)
Net cash provided by financing activities	1,136,858	390,746
Decrease in cash and cash equivalents	$(88,007)	$(190,569)

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil prices on a portion of our production, thereby mitigating our exposure to oil price declines, but these transactions may also limit our cash flow in periods of rising oil prices. For additional information on the impact of changing prices on our financial position, see "Item 3. Quantitative and Qualitative Disclosures about Market Risk."

Cash flows provided by operating activities

Net cash provided by operating activities was $536.7 million and $282.1 million for the nine months ended September 30, 2013 and 2012, respectively. The increase in cash flows provided by operating activities for the period ended September 30, 2013 as compared to 2012 was primarily the result of our 50% increase in oil and natural gas production coupled with an increase in well completion services and related product sales related to non-affiliated working interest owners.

Cash flows used in investing activities

Net cash used in investing activities was $1,761.5 million and $863.4 million during the nine months ended September 30, 2013 and 2012, respectively. Net cash used in investing activities during the nine months ended September 30, 2013 was primarily attributable to $986.2 million for restricted cash held in escrow pending the closing of the acquisition of approximately 136,000 net acres in our West Williston project area, which closed on October 1, 2013 (the "West Williston Acquisition"), capital expenditures primarily for drilling and development costs of $654.2 million, and $133.1 million for the acquisition of oil and gas properties, which includes a $72.5 million deposit for the West Williston Acquisition and $54.8 million for the acquisition of approximately 25,000 net acres in our East Nesson project area on September 26, 2013 (the "East Nesson Acquisitions"). Net cash used in investing activities during the

nine months ended September 30, 2013 was primarily attributable to capital expenditures for drilling and development costs.
Our capital expenditures for drilling, development, acquisition, OWS and non-E&P costs are summarized in the following table:

Table of Contents

	Nine Months Ended September 30, 2013 (In thousands)
Project Area:	
West Williston	$357,672
East Nesson	273,293
Sanish	35,484
Acquisitions (1)	127,253
Total E&P capital expenditures (2)	793,702
OWS	6,260
Non-E&P capital expenditures (3)	6,750
Total capital expenditures (4)	$806,712

(1) Acquisitions include $54.8 million for the East Nesson Acquisitions, which closed in September 2013, and the $72.5 million deposit for the West Williston Acquisition, which closed in October 2013.

(2) Total E&P capital expenditures include $15.7 million for OMS, primarily related to pipelines and salt water disposal wells.

(3) Non-E&P capital expenditures include such items as administrative capital and capitalized interest.

(4) Capital expenditures reflected in the table above differ from the amounts shown in the statement of cash flows in our condensed consolidated financial statements because amounts reflected in the table above include accrued liabilities for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

Our total 2013 capital expenditure budget, excluding the East Nesson Acquisitions and the West Williston Acquisition, is $1,020 million, which consists of:

- $897 million of drilling and completion capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS);
- $43 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems;
- $25 million for maintaining and expanding our leasehold position;
- $10 million for micro-seismic work, purchasing seismic data and other test work;
- $21 million for facilities and other miscellaneous E&P capital expenditures;
- $14 million for OWS; and
- $10 million for other non-E&P capital, including items such as administrative capital and capitalized interest.

While we have budgeted $1,020 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. We believe that the net proceeds from our senior unsecured notes, together with cash on hand, cash flows from operating activities and availability under our revolving credit facility, should be sufficient to fund our 2013 capital expenditure budget. However, because the operated wells funded by our 2013 drilling plan represent only a small percentage of our gross identified drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of identified drilling locations should we elect to do so.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Cash flows provided by financing activities

Net cash provided by financing activities was $1,136.9 million and $390.7 million for the nine months ended September 30, 2013 and 2012, respectively. For the nine months ended September 30, 2013, cash sourced through financing activities was primarily provided by the proceeds from the issuance of our senior unsecured notes in September 2013 and borrowings under our revolving credit facility. For the nine months ended September 30, 2012, cash sourced through financing activities was primarily provided by the proceeds from the issuance of our senior unsecured notes in July 2012. For both the

Table of Contents

nine months ended September 30, 2013 and 2012, these cash sources were offset by deferred financing costs related to our senior unsecured notes and the semi-annual redetermination of our borrowing base under our senior secured revolving line of credit as well as the purchases of treasury stock for shares withheld by us equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards.

Senior unsecured notes. On February 2, 2011, we issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”). Interest is payable on the 2019 Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The 2019 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2019 Notes resulted in net proceeds to us of approximately $390.0 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to February 1, 2014, we may redeem up to 35% of the 2019 Notes at a redemption price of 107.25% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2019 Notes remains outstanding after such redemption. Prior to February 1, 2015, we may redeem some or all of the 2019 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, we may redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning on February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

On November 10, 2011, we issued $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the “2021 Notes”). Interest is payable on the 2021 Notes semi-annually in arrears on each May 1 and November 1, commencing May 1, 2012. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2021 Notes resulted in net proceeds to us of approximately $393.4 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to November 1, 2014, we may redeem up to 35% of the 2021 Notes at a redemption price of 106.5% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2021 Notes remains outstanding after such redemption. Prior to November 1, 2016, we may redeem some or all of the 2021 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after November 1, 2016, we may redeem some or all of the 2021 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.25% for the twelve-month period beginning on November 1, 2016, 102.167% for the twelve-month period beginning on November 1, 2017, 101.083% for the twelve-month period beginning on November 1, 2018 and 100.00% beginning on November 1, 2019, plus accrued and unpaid interest to the redemption date.

On July 2, 2012, we issued $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes”). Interest is payable on the 2023 Notes semi-annually in arrears on each January 15 and July 15, commencing January 15, 2013. The 2023 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2023 Notes resulted in net proceeds to us of approximately $392.4 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

At any time prior to July 15, 2015, we may redeem up to 35% of the 2023 Notes at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2023 Notes remains outstanding after such redemption. Prior to July 15, 2017, we may redeem some or all of the 2023 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after July 15, 2017, we may redeem some or all of the 2023 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.438% for the twelve-month period beginning on July 15, 2017, 102.292% for the twelve-month period beginning on July 15, 2018, 101.146% for the twelve-month period beginning on July 15, 2019 and 100.00% beginning on July 15, 2020, plus accrued and unpaid interest to the redemption date.

On September 24, 2013, we issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the "2022 Notes"). Interest is payable on the 2022 Notes semi-annually in arrears on each March 15 and September 15, commencing March 15, 2014. The 2022 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2022 Notes resulted in net proceeds to us of approximately $983.0 million, which we used to fund a portion of the $1,478.6 million purchase price of the West Williston Acquisition.

At any time prior to September 15, 2017, we may redeem up to 35% of the 2022 Notes at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding after such redemption. Prior to September 15, 2017, we may redeem some or all of the 2022 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after September 15, 2017, we may redeem some or all of the 2022 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.438% for the twelve-month period beginning on September 15, 2017, 101.719% for the twelve-month period beginning on September 15, 2018 and 100.00% beginning on September 15, 2019, plus accrued and unpaid interest to the redemption date.

The indentures governing our 2019 Notes, 2021 Notes, 2023 Notes and 2022 Notes (collectively, the "Notes") restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when our Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Senior secured revolving line of credit. On April 5, 2013, we entered into a second amended and restated credit agreement (the "Second Amended Credit Facility"). In connection with entry into the Second Amended Credit Facility, the semi-annual redetermination of our borrowing base was also completed on April 5, 2013, which resulted in an increase to the borrowing base of the Second Amended Credit Facility from $750.0 million to $1,250.0 million. However, we elected to limit the aggregate commitment of the lenders under the Second Amended Credit Facility (the "Lenders") to $900.0 million. In addition, under the Second Amended Credit Facility, the overall credit facility increased from $1,000.0 million to $2,500.0 million. On September 3, 2013, we entered into an amendment to our Second Amended Credit Facility (the "Amendment"). In connection with the Amendment, the lenders under our revolving credit facility completed their regular semi-annual redetermination of the borrowing base scheduled for October 1, 2013. Following the redetermination, our borrowing base increased from $1,250.0 million to $1,500.0 million and elected commitments also totaled $1,500.0 million.

Borrowings under our Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. At our election, interest is generally determined by reference to (i) the London interbank offered rate, or LIBOR, plus an applicable margin between 1.50% and 2.50% per annum; or (ii) a domestic bank prime rate plus an applicable margin between 0.00% and 1.00% per annum.

As of September 30, 2013, we had $160.0 million of borrowings and $5.2 million outstanding letters of credit under our Second Amended Credit Facility, resulting in an unused borrowing base capacity of $1,334.8 million. On October 1, 2013, we borrowed an additional $440.0 million under our Second Amended Credit Facility, resulting in total outstanding borrowings under the Second Amended Credit Facility of $600.0 million and an unused borrowing base capacity of $894.8 million. We used the borrowings under the Second Amended Credit Facility to fund the East Nesson Acquisitions and a portion of the West Williston Acquisition.

The Second Amended Credit Facility also contains certain financial covenants and customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under our Second Amended Credit Facility to be immediately due and payable. As of September 30, 2013, we were in compliance with the financial covenants of our Second Amended Credit Facility.

Fair Value of Financial Instruments

See Note 5 to our unaudited condensed consolidated financial statements for a discussion of our money market funds and derivative instruments and their related fair value measurements. See also Item 3. "Quantitative and Qualitative Disclosures About Market Risk" below.

Contractual Obligations

We have the following contractual obligations and commitments as of September 30, 2013 (in thousands):

32

Table of Contents

Contractual Obligations	Total	Within 1 Year	1-3 Years	3-5 Years	More Than 5 Years
Operating leases (1)	$11,491	$2,838	$5,751	$2,902	$—
Drilling rig commitments (1)	24,852	20,604	4,248	—	—
Volume commitment agreements (1)	55,490	4,576	25,689	21,565	3,660
Investment commitment (1)	7,227	—	7,227	—	—
Senior unsecured notes (2)	2,200,000	—	—	—	2,200,000
Interest payments on senior unsecured notes (2)	1,267,399	123,024	302,500	302,500	539,375
Borrowings under revolving credit facility (2)	160,000	—	—	160,000	—
Interest payments on borrowings under revolving credit facility (2)	1,574	1,574	—	—	—
Asset retirement obligations (3)	27,431	432	1,422	415	25,162
Total	$3,755,464	$153,048	$346,837	$487,382	$2,768,197

(1) See Note 13 to our unaudited condensed consolidated financial statements for a description of our operating leases, drilling rig commitments, volume commitment agreements and investment commitment.

(2) See Note 7 to our unaudited condensed consolidated financial statements for a description of our senior unsecured notes and revolving credit facility.

(3) 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 environment. See Note 8 to our unaudited condensed consolidated financial statements.

Critical Accounting Policies and Estimates

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2012 Annual Report other than those noted below.

Restricted Cash

Restricted cash represents aggregate net proceeds from the issuance of the 2022 Notes, which were held in escrow as of September 30, 2013 pending the closing of the West Williston Acquisition. If the West Williston Acquisition had not closed prior to December 12, 2013, we would have been required to use the restricted cash to redeem all of the 2022 Notes at a redemption price equal to 100% of the initial offering price, plus accrued and unpaid interest through the date of redemption.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the Securities and Exchange Commission (“SEC”). In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with accounting principles generally accepted in the United States of America. See Note 13 to our unaudited condensed consolidated financial statements for a description of our commitments and contingencies.

Table of Contents

Item 3. — Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2012 Annual Report, as well as with the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

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.

Commodity price exposure risk. We are exposed to market risk as the prices of oil and natural gas fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative instruments in the past and expect to enter into derivative instruments in the future to cover a significant portion of our future production.

We utilize derivative financial instruments to manage risks related to changes in oil prices. As of September 30, 2013, we utilized two-way and three-way collar options, put spreads, swaps and swaps with sub-floors to reduce the volatility of oil prices on a significant portion of our future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be WTI crude oil index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A put spread is a combination of a purchased put and a sold put, and in this case does not include a sold call, allowing the volumes under this contract to have no established maximum price (ceiling). A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A swap with a sub-floor is a swap coupled with a sold put (sub-floor) at which point the minimum price would be WTI crude oil index price plus the difference between the swap and the sold put strike price.

We recognize all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.

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

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Weighted Average Prices Swap ($/Barrel)	Sub-Floor	Floor	Ceiling	Fair Value Asset (Liability) (In thousands)
2013	Two-way collars	836,000			$92.11	$103.45	$(2,636)
2013	Three-way collars	832,330		$67.63	92.01	110.97	(118)
2013	Put spreads	168,670		70.89	90.89		4
2013	Swaps	880,500	$97.29				(5,118)
2014	Two-way collars	1,510,000			90.77	102.06	(159)
2014	Three-way collars	3,530,530		70.30	90.65	105.64	2,497
2014	Put spreads	11,470		70.00	90.00		10
2014	Swaps	2,218,500	95.87				(2,486)
2014	Swaps with sub-floors	2,004,000	92.60	70.00			(7,202)
2015	Two-way collars	108,500			90.00	99.86	284
2015	Three-way collars	263,500		70.59	90.59	105.25	723
2015	Swaps	108,500	93.07				148
2015		186,000	92.60	70.00			(80)

Swaps with sub-floors	
	$(14,133)

Interest rate risk. We had (i) $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum, (ii) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum and (iii) $1,400.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum outstanding at September 30, 2013. At September 30, 2013, we had $160.0 million of borrowings and $5.2 million letters of credit outstanding under our Second Amended Credit Facility, which were subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate ("LIBOR") loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or "ABR" loan). At September 30, 2013, the outstanding borrowings under our Second Amended Credit Facility bore interest at LIBOR plus a margin of 1.5%. We do not currently, but may in the future, utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to debt issued under our Second Amended Credit Facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions, most of which are lenders under our Second Amended Credit Facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the hedged volumes placed under individual contracts.

While we do not require all of our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, the financial ability of the customer's parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. Several of our significant customers for oil and natural gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

We may, from time to time, purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. Our investment policy requires that our counterparties have minimum credit ratings thresholds and provides maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers being unable to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If a commercial paper issuer is unable to return investment proceeds to us at the maturity date, it could take a significant amount of time to recover all or a portion of the assets originally invested. Our commercial paper balance was $36,000 at September 30, 2013.

Most of the counterparties on our derivative instruments currently in place are lenders under our Second Amended Credit Facility with investment grade ratings. We are likely to enter into future derivative instruments with these or other lenders under our Second Amended Credit Facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative liability position of $14.1 million at September 30, 2013.

Item 4. — Controls and Procedures

Evaluation of disclosure controls and procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO"), our principal executive officer; Chief Financial Officer ("CFO"), our principal financial officer; and Chief Accounting Officer ("CAO"), the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of September 30, 2013. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO, CFO and CAO as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, our CEO, CFO and CAO have concluded that our disclosure controls and procedures were effective at September 30, 2013.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended September 30, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II — OTHER INFORMATION

Item 1. — Legal Proceedings

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

Item 1A. — Risk Factors

Our business faces many risks. Any of the risks discussed elsewhere 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.

For a discussion of our potential risks and uncertainties, see the information in Item 1A. "Risk Factors" in our 2012 Annual Report. Except for the risk factor set forth below, there have been no material changes in our risk factors from those described in our 2012 Annual Report.

We are subject to risks in connection with acquisitions, including the West Williston Acquisition and the East Nesson Acquisitions, because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of substantially all the assets we acquired in the West Williston Acquisition and the East Nesson Acquisitions as well as other producing properties that we acquire requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the seller's title to the properties, which may be less than expected at the time of signing the purchase agreement; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities or title defects in excess of the amounts claimed by us before closing and acquire properties on an "as is" basis. Indemnification from the sellers will generally be effective only during the 12-month period after the closing and subject to certain dollar limitations and minimums. We may not be able to collect on such indemnification because of disputes with the sellers or their inability to pay. Moreover, there is a risk that we could ultimately be liable for unknown obligations related to the West Williston Acquisition and the East Nesson Acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;

- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

Table of Contents

The process of integrating assets, including the assets acquired in the West Williston Acquisition and the East Nesson Acquisitions, could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in the West Williston Acquisition, the East Nesson Acquisitions or another acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.

Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

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

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

Issuer purchases of equity securities. The following table contains information about our acquisition of equity securities during the three months ended September 30, 2013:

Period	Total Number of Shares Exchanged (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
July 1 - July 31, 2013	787	$40.15	—	—
August 1 - August 31, 2013	20,881	43.37	—	—
September 1 - September 30, 2013	2,997	39.58	—	—
Total	24,665	$42.81	—	—

(1) Represent shares that employees surrendered back to the Company that equaled in value the amount of taxes needed for payroll tax withholding obligations upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of our common stock.

Table of Contents

Item 6. — Exhibits

Exhibit No.	Description of Exhibit
2.1	Purchase and Sale Agreement, dated September 4, 2013, by and among Oasis Petroleum North America LLC and two undisclosed private sellers (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed September 5, 2013).
4.1	Fourth Supplemental Indenture dated as of September 24, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 25, 2013, and incorporated herein by reference).
4.2	Registration Rights Agreement dated as of September 24, 2013 among the Company, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K filed on September 25, 2013, and incorporated herein by reference).
10.1	Second Amended and Restated Credit Agreement, dated as of April 5, 2013, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 9, 2013, and incorporated herein by reference).
10.2	First Amendment to Second Amended and Restated Credit Agreement dated as of September 3, 2013 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 5, 2013, and incorporated herein by reference).
10.3	Purchase Agreement dated as of September 10, 2013 among the Company, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 11, 2013, and incorporated herein by reference).
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS (a)	XBRL Instance Document.
101.SCH (a)	XBRL Schema Document.
101.CAL (a)	XBRL Calculation Linkbase Document.
101.DEF (a)	XBRL Definition Linkbase Document.

101.LAB (a)	XBRL Labels Linkbase Document.
101.PRE (a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

		OASIS PETROLEUM INC.
Date: November 7, 2013	By:	/s/ Thomas B. Nusz Thomas B. Nusz Chairman, President and Chief Executive Officer (Principal Executive Officer)
	By:	/s/ Michael H. Lou Michael H. Lou Executive Vice President and Chief Financial Officer (Principal Financial Officer)
	By:	/s/ Roy W. Mace Roy W. Mace Senior Vice President, Chief Accounting Officer (Principal Accounting Officer)

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description of Exhibit
2.1	Purchase and Sale Agreement, dated September 4, 2013, by and among Oasis Petroleum North America LLC and two undisclosed private sellers (incorporated by reference to Exhibit 2.1 to the Company’s Current Report on Form 8-K filed September 5, 2013).
4.1	Fourth Supplemental Indenture dated as of September 24, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K filed on September 25, 2013, and incorporated herein by reference).
4.2	Registration Rights Agreement dated as of September 24, 2013 among the Company, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers (filed as Exhibit 4.2 to the Company’s Current Report on Form 8-K filed on September 25, 2013, and incorporated herein by reference).
10.1	Second Amended and Restated Credit Agreement, dated as of April 5, 2013, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on April 9, 2013, and incorporated herein by reference).
10.2	First Amendment to Second Amended and Restated Credit Agreement dated as of September 3, 2013 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on September 5, 2013, and incorporated herein by reference).
10.3	Purchase Agreement dated as of September 10, 2013 among the Company, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on September 11, 2013, and incorporated herein by reference).
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS (a)	XBRL Instance Document.
101.SCH (a)	XBRL Schema Document.
101.CAL (a)	XBRL Calculation Linkbase Document.

101.DEF (a)	XBRL Definition Linkbase Document.
101.LAB (a)	XBRL Labels Linkbase Document.
101.PRE (a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.

40