Oasis Petroleum Inc.
Form 10-Q
November 08, 2012
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

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

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

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 x	Accelerated filer ¨
Non-accelerated filer ¨ (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 x

Number of shares of the registrant s common stock outstanding at November 5, 2012: 93,366,522 shares.

Table of Contents

OASIS PETROLEUM INC.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2012

TABLE OF CONTENTS

	Page
PART I FINANCIAL INFORMATION	1
Item 1. Financial Statements (Unaudited)	1
Condensed Consolidated Balance Sheet at September 30, 2012 and December 31, 2011	1
Condensed Consolidated Statement of Operations for the Three and Nine Months Ended September 30, 2012 and 2011	2
Condensed Consolidated Statement of Changes in Stockholders Equity for the Nine Months Ended September 30, 2012	3
Condensed Consolidated Statement of Cash Flows for the Nine Months Ended September 30, 2012 and 2011	4
Notes to Condensed Consolidated Financial Statements	5
Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations	21
Item 3. Quantitative and Qualitative Disclosures About Market Risk	32
Item 4. Controls and Procedures	33
PART II OTHER INFORMATION	34
Item 1. Legal Proceedings	34
Item 1A. Risk Factors	34
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	34
Item 6. Exhibits	35
SIGNATURES	36
EXHIBIT INDEX	37

Table of Contents

PART I FINANCIAL INFORMATION

Item 1. Financial Statements (Unaudited)

Oasis Petroleum Inc.

Condensed Consolidated Balance Sheet

(Unaudited)

	September 30, 2012	December 31, 2011
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 280,303	$ 470,872
Short-term investments	126,213	19,994
Accounts receivable oil and gas revenues	104,965	52,164
Accounts receivable joint interest partners	83,630	67,268
Inventory	21,142	3,543
Prepaid expenses	4,030	2,140
Advances to joint interest partners	4,025	3,935
Derivative instruments	17,320	
Deferred income taxes		3,233
Other current assets	78	491
Total current assets	641,706	623,640
Property, plant and equipment		
Oil and gas properties (successful efforts method)	2,079,016	1,235,357
Other property and equipment	45,261	20,859
Less: accumulated depreciation, depletion, amortization and impairment	(320,478)	(176,261)
Total property, plant and equipment, net	1,803,799	1,079,955
Derivative instruments	10,047	4,362
Deferred costs and other assets	25,349	19,425
Total assets	$ 2,480,901	$ 1,727,382
LIABILITIES AND STOCKHOLDERS EQUITY		
Current liabilities		
Accounts payable	$ 30,954	$ 12,207
Advances from joint interest partners	26,572	9,064
Revenues and production taxes payable	64,091	19,468
Accrued liabilities	200,544	119,692
Accrued interest payable	22,481	15,774
Derivative instruments	1,273	5,907
Deferred income taxes	3,782	
Other current liabilities	5,256	472
Total current liabilities	354,953	182,584
Long-term debt	1,200,000	800,000

Asset retirement obligations	20,529	13,075
Derivative instruments	360	3,505
Deferred income taxes	152,617	92,983
Other liabilities	2,078	997
Total liabilities	1,730,537	1,093,144
Commitments and contingencies (Note 12)		
Stockholders equity		
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,435,593 issued and 93,369,468 outstanding at September 30, 2012; 92,483,393 issued and 92,460,914 outstanding at December 31, 2011	923	921
Treasury stock, at cost; 66,125 and 22,479 shares at September 30, 2012 and December 31, 2011, respectively	(1,901)	(602)
Additional paid-in-capital	653,999	647,374
Retained earnings (deficit)	97,343	(13,455)
Total stockholders equity	750,364	634,238
Total liabilities and stockholders equity	$ 2,480,901	$ 1,727,382

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

Table of Contents

Oasis Petroleum Inc.

Condensed Consolidated Statement of Operations

(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$ 178,748	$ 87,596	$ 461,857	$ 213,546
Well services revenues	5,963		10,484	
Total revenues	184,711	87,596	472,341	213,546
Expenses				
Lease operating expenses	16,134	9,597	37,979	21,178
Well services operating expenses	5,420		7,104	
Marketing, transportation and gathering expenses	2,744	238	7,283	797
Production taxes	16,433	8,873	43,419	22,041
Depreciation, depletion and amortization	57,684	20,859	140,783	47,771
Exploration expenses	336	54	3,171	345
Impairment of oil and gas properties	36	396	2,607	3,313
General and administrative expenses	13,886	7,306	39,622	19,870
Total expenses	112,673	47,323	281,968	115,315
Operating income	72,038	40,273	190,373	98,231
Other income (expense)				
Net gain (loss) on derivative instruments	(22,441)	71,224	33,568	67,105
Interest expense	(20,979)	(6,786)	(48,952)	(18,745)
Other income	1,147	524	2,521	1,215
Total other income (expense)	(42,273)	64,962	(12,863)	49,575
Income before income taxes	29,765	105,235	177,510	147,806
Income tax expense	11,451	38,946	66,712	55,015
Net income	$ 18,314	$ 66,289	$ 110,798	$ 92,791
Earnings per share:				
Basic and diluted (Note 11)	$ 0.20	$ 0.72	$ 1.20	$ 1.01
Weighted average shares outstanding:				
Basic (Note 11)	92,186	92,060	92,164	92,052
Diluted (Note 11)	92,416	92,164	92,343	92,208

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	Retained Earnings	Total Stockholders
	Shares	Amount	Shares	Amount	Paid-in-Capital	(Deficit)	Equity
Balance as of December 31, 2011	92,461	$ 921	22	$ (602)	$ 647,374	$ (13,455)	$ 634,238
Stock-based compensation	952				6,627		6,627
Vesting of restricted shares		2			(2)		
Treasury stock tax withholdings	(44)		44	(1,299)			(1,299)
Net income						110,798	110,798
Balance as of September 30, 2012	93,369	$ 923	66	$ (1,901)	$ 653,999	$ 97,343	$ 750,364

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,	
	2012	2011
	(In thousands)	
Cash flows from operating activities:		
Net income	$ 110,798	$ 92,791
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	140,783	47,771
Impairment of oil and gas properties	2,607	3,313
Deferred income taxes	66,648	55,015
Derivative instruments	(33,568)	(67,105)
Stock-based compensation expenses	6,627	2,592
Debt discount amortization and other	2,038	1,041
Working capital and other changes:		
Change in accounts receivable	(69,163)	(41,286)
Change in inventory	(26,790)	(1,850)
Change in prepaid expenses	(2,009)	(297)
Change in other current assets	413	(337)
Change in other assets	(119)	(103)
Change in accounts payable and accrued liabilities	79,079	47,820
Change in other current liabilities	4,784	
Change in other liabilities		317
Net cash provided by operating activities	282,128	139,682
Cash flows from investing activities:		
Capital expenditures	(777,426)	(386,927)
Derivative settlements	2,784	(4,831)
Purchases of short-term investments	(126,213)	(164,913)
Redemptions of short-term investments	19,994	39,974
Advances to joint interest partners	(90)	(408)
Advances from joint interest partners	17,508	8,093
Net cash used in investing activities	(863,443)	(509,012)
Cash flows from financing activities:		
Proceeds from issuance of senior notes	400,000	400,000
Purchases of treasury stock	(1,299)	(562)
Debt issuance costs	(7,955)	(10,027)
Net cash provided by financing activities	390,746	389,411
Increase (decrease) in cash and cash equivalents	(190,569)	20,081
Cash and cash equivalents:		
Beginning of period	470,872	143,520
End of period	$ 280,303	$ 163,601
Supplemental non-cash transactions:		

Change in accrued capital expenditures	$ 71,572	$ 23,422
Change in asset retirement obligations	7,774	3,925

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

Table of Contents

OASIS PETROLEUM INC.

Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Organization and Operations of the Company

Organization

Oasis Petroleum Inc. (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 May 2007, the Company formed Oasis Petroleum North America LLC (OPNA), a Delaware limited liability company, to conduct its domestic oil and natural gas exploration and production activities. In April 2008, the Company formed Oasis Petroleum International LLC (OPI), a Delaware limited liability company, to conduct business development activities outside of the United States of America. As of September 30, 2012, OPI had no business activities or material assets. In June 2011, the Company formed Oasis Well Services LLC (OWS), a Delaware limited liability company, to provide well services to OPNA. In July 2011, the Company formed Oasis Petroleum Marketing LLC (OPM), a Delaware limited liability company, to provide marketing services to OPNA.

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 businesses that are complementary to its primary development and production activities, including a marketing business (OPM) and a well services business (OWS).

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: OP LLC, OPNA, OPI, OWS and OPM. 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, 2011 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, 2011 (2011 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 2011 Annual Report other than those noted below.

Stock-Based Compensation Performance Share Units

The Company recognizes compensation expense for its performance share units (PSUs) granted to its officers. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the

performance period, which is generally the vesting period. The fair value of the PSUs is based on the calculation derived from a Monte Carlo simulation model. The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probable assessment. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the stock-based compensation expense recognized. Stock-based compensation expense recorded for PSUs is included in general and administrative expenses on the Company s Condensed Consolidated Statement of Operations.

Table of Contents

Recent Accounting Pronouncements

Intangible assets. In July 2012, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2012-02, *Intangibles Goodwill and Other Testing Indefinite-Lived Intangible Assets for Impairment* (ASU 2012-02). The objective of ASU 2012-02 is to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by permitting an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired, as a basis for determining whether it is necessary to perform a quantitative impairment test. ASU 2012-02 is effective for interim and annual reporting periods beginning after September 15, 2012. The Company does not expect the adoption of this new guidance to have any impact on its financial position, cash flows or results of operations.

3. Inventory

Equipment and materials consist primarily of tubular goods, well equipment to be used in future drilling or repair operations and well fracturing equipment, 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, 2012	December 31, 2011
	(In thousands)	
Equipment and materials	$ 15,846	$ 2,709
Crude oil inventory	5,296	834
Total inventory	$ 21,142	$ 3,543

4. Property, Plant and Equipment

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

	September 30, 2012	December 31, 2011
	(In thousands)	
Proved oil and gas properties (1)	$ 2,004,433	$ 1,152,532
Less: Accumulated depreciation, depletion, amortization and impairment	(314,787)	(174,948)
Proved oil and gas properties, net	1,689,646	977,584
Unproved oil and gas properties	74,583	82,825
Oil and gas properties, net	1,764,229	1,060,409
Other property and equipment	45,261	20,859
Less: Accumulated depreciation	(5,691)	(1,313)
Other property and equipment, net	39,570	19,546
Total property, plant and equipment, net	$ 1,803,799	$ 1,079,955

(1) Included in the Company s proved oil and gas properties are estimates of future asset retirement costs of $18.5 million and $11.4 million at September 30, 2012 and December 31, 2011, respectively. In addition, the Company s proved oil and gas properties include cumulative capitalized interest of $5.6 million and $3.1 million at September 30, 2012 and December 31, 2011, respectively.

As a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $36,000 and $2.6 million for the three and nine months ended September 30, 2012, respectively, and $0.4 million and $3.3 million for the three and nine months ended September 30, 2011, respectively. No impairment charges on proved oil and natural gas properties were recorded for the three and nine months ended September 30, 2012 or 2011.

5. Fair Value Measurements

In accordance with the FASB s authoritative guidance on fair value measurements, the Company s financial assets and liabilities are measured at fair value on a recurring basis. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations 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.

Table of Contents

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, 2012			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets:				
Money market funds	$ 165,737	$	$	$ 165,737
Commodity derivative instruments (see Note 6)		27,367		27,367
Total assets	$ 165,737	$ 27,367	$	$ 193,104
Liabilities:				
Commodity derivative instruments (see Note 6)	$	$ 1,633	$	$ 1,633
Total liabilities	$	$ 1,633	$	$ 1,633

	At fair value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
		(In thousands)		
Assets:				
Money market funds	$ 250,419	$	$	$ 250,419
Commodity derivative instruments (see Note 6)			4,362	4,362
Total assets	$ 250,419	$	$ 4,362	$ 254,781
Liabilities:				
Commodity derivative instruments (see Note 6)	$	$	$ 9,412	$ 9,412
Total liabilities	$	$	$ 9,412	$ 9,412

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, 2012 and December 31, 2011. 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.

Table of Contents

The Level 2 and Level 3 instruments presented in the tables above consist of oil collars, swaps and puts. The fair values of the Company s oil collars, swaps and puts 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 an options pricing model similar to Black-Scholes. 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 determination of the fair values also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in an asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a 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 asset in the amount of $39,000 at September 30, 2012 and a downward adjustment to the fair value of its net derivative liability in the amount of $0.3 million at December 31, 2011.

The Company has adopted the FASB s authoritative guidance amending certain accounting and disclosure requirements related to fair value measurements. The guidance clarifies and modifies some fair value measurement principles under GAAP, including a change in the valuation premise and the application of premiums and discounts, and contains some new disclosure requirements under GAAP. The guidance had no impact on the Company s financial position, cash flows or results of operations for the nine months ended September 30, 2012.

The following table presents a reconciliation of the changes in fair value of the derivative instruments classified as Level 3 in the fair value hierarchy for the periods presented.

	2012	2011
	(In thousands)	
Balance as of January 1	$ (5,050)	$ (10,486)
Total gains or (losses) (realized or unrealized):		
Included in earnings		67,105
Included in other comprehensive income		
Settlements		4,831
Transfers in and out of Level 3 (1)	5,050	
Balance as of September 30	$	$ 61,450
Change in unrealized losses included in earnings relating to derivatives still held at September 30	$	$ 71,936

(1) During the first nine months of 2012, the inputs used to value the Company s commodity derivative instruments were directly or indirectly observable and those contracts were transferred to Level 2.

Fair Value of Other Financial Instruments

The Company s financial instruments, including certain cash and cash equivalents, short-term investments, accounts receivable and accounts payable, are carried at amortized cost, which approximates cost and fair value due to the short-term maturity of these instruments. At September 30, 2012, the Company s cash equivalents and short-term investments were all Level 1 assets. The carrying amount of the Company s long-term debt (senior unsecured notes due 2019, 2021 and 2023 see Note 7) reported in the Condensed Consolidated Balance Sheet at September 30, 2012 is $1,200.0 million with a fair value of $1,276.0 million. The Company s senior unsecured notes are publicly traded and therefore categorized as a Level 1 liability.

Nonfinancial Assets and Liabilities

Asset retirement obligations. The carrying amount of the Company s asset retirement obligations (ARO) in the Condensed Consolidated Balance Sheet at September 30, 2012 is $20.8 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.

Table of Contents

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, 2012 or 2011.

6. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of September 30, 2012, the Company utilized two-way and three-way collar options, swaps and put spreads to reduce the volatility of oil prices on a significant portion of the Company s future expected oil production. 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 realized and unrealized, are recognized in the Other Income (Expense) section of the Condensed Consolidated Statement of Operations as a 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 or receiving a payment to or 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, 2012, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the average West Texas Intermediate crude oil index price:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Average Swap Price	Average Sub-Floor Price	Average Floor Price	Average Ceiling Price	Fair Value Asset (Liability) (In thousands)
2012	Two-Way Collars	819,000			$ 88.61	$ 105.59	$ 975
2012	Three-Way Collars	910,000		$ 66.25	$ 90.25	$ 110.04	841
2012	Swaps	91,000	$ 94.61				130
2013	Two-Way Collars	1,782,000			$ 86.50	$ 98.93	(1,164)
2013	Three-Way Collars	2,023,420		$ 65.30	$ 92.51	$ 112.63	8,561
2013	Put Spreads	1,717,080		$ 70.71	$ 91.24		9,931
2013	Swaps	699,000	$ 96.41				1,850
2014	Two-Way Collars	139,500			$ 86.11	$ 97.69	(84)
2014	Three-Way Collars	1,495,030		$ 70.60	$ 91.43	$ 110.30	3,229
2014	Put Spreads	150,970		$ 71.03	$ 91.03		1,019
2014	Swaps	62,000	$ 96.49				215
2015	Three-Way Collars	124,000		$ 71.25	$ 91.25	$ 109.96	231
							$ 25,734

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

Fair Value of Derivative Instrument Assets (Liabilities)

Commodity	Balance Sheet Location		Fair Value September 30, 2012	Fair Value December 31, 2011
			(In thousands)	
Crude oil	Derivative instruments	current assets	$ 17,320	$
Crude oil	Derivative instruments	non-current assets	10,047	4,362
Crude oil	Derivative instruments	current liabilities	(1,273)	(5,907)
Crude oil	Derivative instruments	non-current liabilities	(360)	(3,505)
Total derivative instruments			$ 25,734	$ (5,050)

Table of Contents

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

	Income Statement Location	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
		(In thousands)		(In thousands)	
Change in unrealized gain (loss) on derivative instruments	Net gain (loss) on derivative instruments	$ (27,690)	$ 71,403	$ 30,784	$ 71,936
Realized gain (loss) on derivative instruments	Net gain (loss) on derivative instruments	5,249	(179)	2,784	(4,831)
Total net gain (loss) on derivative instruments		$ (22,441)	$ 71,224	$ 33,568	$ 67,105

7. Long-Term Debt

Senior unsecured notes. On July 2, 2012, the Company issued $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the 2023 Notes). During 2011, the Company issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the 2019 Notes) and $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the 2021 Notes , and together with the 2023 Notes and the 2019 Notes, the Notes). 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. The issuance of these Notes resulted in aggregate net proceeds to the Company of approximately $1,175.8 million, including $392.4 million on July 2, 2012 for the 2023 Notes and $783.4 during the year ended December 31, 2011 for the 2019 Notes and the 2021 Notes.

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 options is immaterial at September 30, 2012.

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;
- 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.

Table of Contents

Senior secured revolving line of credit. OP LLC, as parent, and OPNA, as borrower, entered into a credit agreement dated June 22, 2007 (as amended and restated, the Amended Credit Facility). The 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 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. On April 3, 2012, the Company entered into its sixth amendment to its Amended Credit Facility. This amendment added two new lenders to the bank group. All other terms and conditions of the Amended Credit Facility remained the same, including the October 6, 2016 maturity date and the $1 billion senior secured revolving line of credit. In connection with the sixth amendment, the semi-annual redetermination of the borrowing base was also completed on April 3, 2012, which resulted in the borrowing base of the Amended Credit Facility increasing from $350 million to $500 million. Effective April 20, 2012, the Company executed an agreement consenting to the resignation of BNP Paribas as the administrative agent and a lender under the Amended Credit Facility. Wells Fargo was appointed successor administrative agent and assumed the credit commitment of BNP Paribas. BNP Paribas remains as a counterparty for the Company s commodity derivative instruments. On June 25, 2012, the Company s lenders waived the mandatory reduction of the Company s borrowing base that otherwise would have occurred as a result of the Company s issuance of the 2023 Notes in July 2012. In addition, on October 2, 2012, the Company entered into its seventh amendment to its Amended Credit Facility (see Note 14 Subsequent Events).

Borrowings under the 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 Amended Credit Facility as an Alternate Based Rate or ABR loan). As of September 30, 2012, any outstanding LIBOR and ABR loans would have borne 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 Amended Credit Facility upon the Company providing advance notification to the lenders under the Amended Credit Facility (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 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 also pays a 0.375% 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, 2012, the 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 not allow a ratio of Total Net Debt (as defined in the Amended Credit Facility) to consolidated EBITDAX (as defined in the Amended Credit Facility) to be greater than 4.0 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 Amended Credit Facility) of consolidated current assets (with exclusions as described in the Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Amended Credit Facility) of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

Table of Contents

The 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 Amended Credit Facility to be immediately due and payable.

As of September 30, 2012, the Company had no borrowings and no outstanding letters of credit issued under the Amended Credit Facility, resulting in an unused borrowing base capacity of $500 million. The Company was in compliance with the financial covenants of the Amended Credit Facility as of September 30, 2012.

Deferred financing costs. As of September 30, 2012, the Company had $24.3 million of deferred financing costs related to the Amended Credit Facility and the senior unsecured notes. The deferred financing costs are included in deferred costs and other assets on the Company s Condensed Consolidated Balance Sheet at September 30, 2012 and are being amortized over the respective terms of the Amended Credit Facility and the senior unsecured notes. The amortization of these deferred financing costs is 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, 2012:

	(In thousands)
Balance at December 31, 2011	$ 13,075
Liabilities incurred during period	5,388
Liabilities settled during period	(42)
Accretion expense during period (1)	612
Revisions to estimates	1,774
Balance at September 30, 2012	$ 20,807

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

The revisions to estimates were primarily due to changes in the estimated useful lives of certain wells. At September 30, 2012, the current portion of the total ARO balance was approximately $0.3 million and is included in accrued liabilities on the Company s Condensed Consolidated Balance Sheet.

9. Stock-Based Compensation

Performance share units. On July 30, 2012, the Company s Board of Directors approved grants of performance share units (PSUs) to officers of the Company pursuant to the Company s 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.

The PSUs are subject to a designated three-year initial performance period beginning on August 1, 2012 and ending on July 31, 2015. 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. 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 to July 16, 2016 to give the recipient the opportunity to earn up to an aggregate of 200% of the initial PSUs granted.

The following table summarizes information related to PSUs held by the Company s officers at September 30, 2012:

	Initial Unit Awards
Non-vested PSUs at December 31, 2011	

Granted	155,220
Vested	
Forfeited	
Non-vested PSUs at September 30, 2012	155,220

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. 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.

Table of Contents

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. No forfeiture rate is assumed for these types of awards.

The following assumptions were used as of September 30, 2012 for the Monte Carlo model to value the stock-based compensation expense of the PSUs granted:

	2012 PSUs
Forecast period (years)	4.01
Risk-free rate	0.46%
Oasis volatility	51.00%

The fair value per PSU at September 30, 2012 was $26.22. Stock-based compensation expense recorded for these PSUs for both the three and nine months ended September 30, 2012 was $0.2 million and is included in general and administrative expenses on the Condensed Consolidated Statement of Operations. Unrecognized expense as of September 30, 2012 for all outstanding PSUs was $3.9 million and will be recognized over a four-year requisite service period. No stock-based compensation expense was recorded for the three or nine months ended September 30, 2011 as the Company had not issued PSUs prior to July 2012.

10. Income Taxes

The Company s effective tax rate for the three and nine months ended September 30, 2012 was 38.5% and 37.6%, respectively, and was 37.0% and 37.2% for the three and nine months ended September 30, 2011, 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, 2012, 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, 2012 recorded in noncurrent 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, 2012, 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, 2012 and 2011:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	(In thousands)		(In thousands)	
Basic weighted average common shares outstanding	92,186	92,060	92,164	92,052
Dilution effect of stock awards at end of period	230	104	179	156
Diluted weighted average common shares outstanding	92,416	92,164	92,343	92,208

Anti-dilutive stock-based compensation awards	748	281	541	174

Table of Contents

12. Commitments and Contingencies

Lease obligations. The Company s total rental commitments under leases for office space and other property and equipment at September 30, 2012 were $14.0 million.

Drilling contracts. As of September 30, 2012, 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 $50.4 million as of September 30, 2012 for the days remaining through the end of the primary terms of the contracts.

Volume commitment agreements. As of September 30, 2012, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 24.7 MMBbl and 15.7 Bcf from its Williston Basin project areas within a specified timeframe. Future obligations under these agreements were approximately $75.4 million as of September 30, 2012.

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.

13. 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. The consolidating statement of cash flows for the nine months ended September 30, 2011 includes a revision in presentation in the Issuer column, which increased cash flows from operating activities by $105.8 million and reduced cash flows from financing activities by the same amount. These revisions are eliminated in consolidation and have no effect on the Guarantors or consolidated financial statements.

Table of Contents

Condensed Consolidating Balance Sheet

(In thousands, except share data)

	September 30, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$ 231,170	$ 49,133	$	$ 280,303
Short-term investments	126,213			126,213
Accounts receivable oil and gas revenues		104,965		104,965
Accounts receivable joint interest partners		83,630		83,630
Accounts receivable from affiliates	291	3,559	(3,850)	
Inventory		21,142		21,142
Prepaid expenses	501	3,529		4,030
Advances to joint interest partners		4,025		4,025
Derivative instruments		17,320		17,320
Other current assets	78			78
Total current assets	358,253	287,303	(3,850)	641,706
Property, plant and equipment				
Oil and gas properties (successful efforts method)		2,079,016		2,079,016
Other property and equipment		45,261		45,261
Less: accumulated depreciation, depletion, amortization and impairment		(320,478)		(320,478)
Total property, plant and equipment, net		1,803,799		1,803,799
Investments in and advances to subsidiaries	1,563,143		(1,563,143)	
Derivative instruments		10,047		10,047
Deferred income taxes	33,616		(33,616)	
Deferred costs and other assets	21,405	3,944		25,349
Total assets	$ 1,976,417	$ 2,105,093	$ (1,600,609)	$ 2,480,901
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities				
Accounts payable	$ 4	$ 30,950	$	$ 30,954
Accounts payable from affiliates	3,559	291	(3,850)	
Advances from joint interest partners		26,572		26,572
Revenues and production taxes payable		64,091		64,091
Accrued liabilities	25	200,519		200,544
Accrued interest payable	22,465	16		22,481
Derivative instruments		1,273		1,273
Deferred income taxes		3,782		3,782
Other current liabilities		5,256		5,256
Total current liabilities	26,053	332,750	(3,850)	354,953
Long-term debt	1,200,000			1,200,000
Asset retirement obligations		20,529		20,529
Derivative instruments		360		360

Deferred income taxes		186,233	(33,616)	152,617
Other liabilities		2,078		2,078
Total liabilities	1,226,053	541,950	(37,466)	1,730,537
Stockholders equity				
Capital contributions from affiliates		1,400,817	(1,400,817)	
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,435,593 issued and 93,369,468 outstanding	923			923
Treasury stock, at cost; 66,125 shares	(1,901)			(1,901)
Additional paid-in-capital	653,999	8,743	(8,743)	653,999
Retained earnings	97,343	153,583	(153,583)	97,343
Total stockholders equity	750,364	1,563,143	(1,563,143)	750,364
Total liabilities and stockholders equity	$ 1,976,417	$ 2,105,093	$ (1,600,609)	$ 2,480,901

Table of Contents

Condensed Consolidating Balance Sheet

(In thousands, except share data)

	December 31, 2011			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$ 443,482	$ 27,390	$	$ 470,872
Short-term investments	19,994			19,994
Accounts receivable oil and gas revenues		52,164		52,164
Accounts receivable joint interest partners		67,268		67,268
Accounts receivable from affiliates	88	1,540	(1,628)	
Inventory		3,543		3,543
Prepaid expenses	309	1,831		2,140
Advances to joint interest partners		3,935		3,935
Deferred income taxes		3,233		3,233
Other current assets	18	473		491
Total current assets	463,891	161,377	(1,628)	623,640
Property, plant and equipment				
Oil and gas properties (successful efforts method)		1,235,357		1,235,357
Other property and equipment		20,859		20,859
Less: accumulated depreciation, depletion, amortization and impairment		(176,261)		(176,261)
Total property, plant and equipment, net		1,079,955		1,079,955
Investments in and advances to subsidiaries	958,880		(958,880)	
Derivative instruments		4,362		4,362
Deferred income taxes	13,158		(13,158)	
Deferred costs and other assets	15,742	3,683		19,425
Total assets	$ 1,451,671	$ 1,249,377	$ (973,666)	$ 1,727,382
LIABILITIES AND STOCKHOLDERS EQUITY				
Current liabilities				
Accounts payable	$ 23	$ 12,184	$	$ 12,207
Accounts payable from affiliates	1,540	88	(1,628)	
Advances from joint interest partners		9,064		9,064
Revenues and production taxes payable		19,468		19,468
Accrued liabilities	103	119,589		119,692
Accrued interest payable	15,767	7		15,774
Derivative instruments		5,907		5,907
Other current liabilities		472		472
Total current liabilities	17,433	166,779	(1,628)	182,584
Long-term debt	800,000			800,000
Asset retirement obligations		13,075		13,075
Derivative instruments		3,505		3,505
Deferred income taxes		106,141	(13,158)	92,983

Other liabilities		997		997
Total liabilities	817,433	290,497	(14,786)	1,093,144
Stockholders equity				
Capital contributions from affiliates		941,575	(941,575)	
Common stock, $0.01 par value; 300,000,000 shares authorized; 92,483,393 issued and 92,460,914 outstanding	921			921
Treasury stock, at cost; 22,479 shares	(602)			(602)
Additional paid-in-capital	647,374	8,743	(8,743)	647,374
Retained earnings (deficit)	(13,455)	8,562	(8,562)	(13,455)
Total stockholders equity	634,238	958,880	(958,880)	634,238
Total liabilities and stockholders equity	$ 1,451,671	$ 1,249,377	$ (973,666)	$ 1,727,382

Table of Contents

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	(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

Table of Contents

Condensed Consolidating Statement of Operations

(In thousands)

	Three Months Ended September 30, 2011			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Oil and gas revenues	$	$ 87,596	$	$ 87,596
Expenses				
Lease operating expenses		9,597		9,597
Marketing, transportation and gathering expenses		238		238
Production taxes		8,873		8,873
Depreciation, depletion and amortization		20,859		20,859
Exploration expenses		54		54
Impairment of oil and gas properties		396		396
General and administrative expenses	1,282	6,024		7,306
Total expenses	1,282	46,041		47,323
Operating income (loss)	(1,282)	41,555		40,273
Other income (expense)				
Equity in earnings in subsidiaries	71,445		(71,445)	
Net gain on derivative instruments		71,224		71,224
Interest expense	(6,495)	(291)		(6,786)
Other income	282	242		524
Total other income (expense)	65,232	71,175	(71,445)	64,962
Income before income taxes	63,950	112,730	(71,445)	105,235
Income tax benefit (expense)	2,339	(41,285)		(38,946)
Net income	$ 66,289	$ 71,445	$ (71,445)	$ 66,289

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 revenues		10,484		10,484
Total revenues		472,341		472,341
Expenses				
Lease operating expenses		37,979		37,979

Well services 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	(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

Table of Contents

Condensed Consolidating Statement of Operations

(In thousands)

	Nine Months Ended September 30, 2011			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Oil and gas revenues	$	$ 213,546	$	$ 213,546
Expenses				
Lease operating expenses		21,178		21,178
Marketing, transportation and gathering expenses		797		797
Production taxes		22,041		22,041
Depreciation, depletion and amortization		47,771		47,771
Exploration expenses		345		345
Impairment of oil and gas properties		3,313		3,313
General and administrative expenses	3,863	16,007		19,870
Total expenses	3,863	111,452		115,315
Operating income (loss)	(3,863)	102,094		98,231
Other income (expense)				
Equity in earnings in subsidiaries	105,832		(105,832)	
Net gain on derivative instruments		67,105		67,105
Interest expense	(17,909)	(836)		(18,745)
Other income	946	269		1,215
Total other income (expense)	88,869	66,538	(105,832)	49,575
Income before income taxes	85,006	168,632	(105,832)	147,806
Income tax benefit (expense)	7,785	(62,800)		(55,015)
Net income	$ 92,791	$ 105,832	$ (105,832)	$ 92,791

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:	$ 110,798	$ 145,021	$ (145,021)	$ 110,798
Net income				
Adjustments to reconcile net income to net cash provided by (used in) 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 (used in) operating activities	(38,527)	320,655		282,128
Cash flows from investing activities:				
Capital expenditures		(777,426)		(777,426)
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 to joint interest partners		(90)		(90)
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
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

Table of Contents

Condensed Consolidating Statement of Cash Flows

(In thousands)

	Nine Months Ended September 30, 2011			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$ 92,791	$ 105,832	$ (105,832)	$ 92,791
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(105,832)		105,832	
Depreciation, depletion and amortization		47,771		47,771
Impairment of oil and gas properties		3,313		3,313
Deferred income taxes	(7,785)	62,800		55,015
Derivative instruments		(67,105)		(67,105)
Stock-based compensation expenses	2,592			2,592
Debt discount amortization and other	793	248		1,041
Working capital and other changes:				
Change in accounts receivable	(80)	(42,306)	1,100	(41,286)
Change in inventory		(1,850)		(1,850)
Change in prepaid expenses	(227)	(70)		(297)
Change in other current assets	(337)			(337)
Change in other assets	(100)	(3)		(103)
Change in accounts payable and accrued liabilities	5,864	43,056	(1,100)	47,820
Change in other liabilities		317		317
Net cash provided by (used in) operating activities	(12,321)	152,003		139,682
Cash flows from investing activities:				
Capital expenditures		(386,927)		(386,927)
Derivative settlements		(4,831)		(4,831)
Purchases of short-term investments	(164,913)			(164,913)
Redemptions of short-term investments	39,974			39,974
Advances to joint interest partners		(408)		(408)
Advances from joint interest partners		8,093		8,093
Net cash used in investing activities	(124,939)	(384,073)		(509,012)
Cash flows from financing activities:				
Proceeds from issuance of senior notes	400,000			400,000
Purchases of treasury stock	(562)			(562)
Debt issuance costs	(9,650)	(377)		(10,027)
Investment in / capital contributions from affiliates	(252,138)	252,138		
Net cash provided by financing activities	137,650	251,761		389,411
Increase in cash and cash equivalents	390	19,691		20,081
Cash and cash equivalents at beginning of period	119,940	23,580		143,520
Cash and cash equivalents at end of period	$ 120,330	$ 43,271	$	$ 163,601

14. 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.

Senior secured revolving line of credit. On October 2, 2012, the Company entered into its seventh amendment to its Amended Credit Facility (the Seventh Amendment). In connection with this amendment, the semi-annual redetermination of the Company s borrowing base was completed on October 2, 2012, which resulted in an increase to the borrowing base of its Amended Credit Facility from $500 million to $750 million. However, the Company elected to have the lenders aggregate commitment remain at $500 million. The Seventh Amendment provides that the Company may increase its aggregate commitment from $500 million to $750 million by increasing the commitment of one or more lender(s). The Seventh Amendment also added a requirement that the Company maintain a ratio of consolidated EBITDAX (as defined in the Amended Credit Facility) to consolidated Interest Expense (as defined in the Amended Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter. This covenant replaces the Total Net Debt (as defined in the Amended Credit Facility) to consolidated EBITDAX ratio covenant described in Note 7 above. All other significant rates, terms and conditions of the Amended Credit Facility remained the same (see Note 7 Long-Term Debt).

Derivative instruments. In October 2012, the Company entered into new two-way and three-way costless collar options, all of which settle monthly based on the West Texas Intermediate crude oil index price, for a total notional amount of 668,000 barrels in 2013, 396,000 barrels in 2014 and 31,000 barrels in 2015. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

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, 2011 (2011 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 similar expressions are int 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 2011 Annual Report and in our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012 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 a services company;

the amount, nature and timing of capital expenditures;

availability and terms of capital;

property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

drilling and completion of wells;

infrastructure for salt water disposal;

gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and domestically;

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;

Table of Contents

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 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 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. We also operate businesses that are complementary to our primary development and production activities, including a marketing business, Oasis Petroleum Marketing LLC (OPM), and a well services business, Oasis Well Services LLC (OWS). The revenues and expenses related to work performed by OPM and OWS for Oasis Petroleum North America LLC 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, during the first three quarters of 2012, we began to actively increase the number of operated wells that we have connected to a third-party oil gathering system in our West Williston project area. At the end of September 2012, the Company had 108 operated wells connected, up from only three operated wells that were connected at the beginning of 2012. We currently flow approximately 60% of our gross operated oil production on the third-party oil gathering system. This same third-party has also agreed to extend the system into our East Nesson project area in 2013, which we expect will increase the gross operated oil production that will flow on the system to over 80% by mid-year 2013.

Table of Contents

Changes in commodity prices may also significantly affect the economic viability of drilling projects as well as the economic valuation and economic recovery of oil and gas reserves. Oil prices have increased significantly since 2009. As a result of higher commodity prices and continued successes in the application of completion technologies in the Bakken formation, there were approximately 220 active drilling rigs in the Williston Basin at September 30, 2012. Both takeaway capacity and production have rapidly grown in the Williston Basin throughout 2012. 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, differentials began to narrow, primarily due to transportation capacity additions outpacing production growth.

Our large concentrated acreage position potentially provides us with a multi-year inventory of drilling projects and requires some forward planning visibility for obtaining services. Our ability to develop and hold our existing undeveloped leasehold acreage is primarily dependent upon having access to drilling rigs and completion services. The utilization of existing drilling rigs and of existing completion service equipment in the Williston Basin is at an all-time high. This has resulted in drilling rigs, completion equipment and crews being imported from Canada and other parts of the United States. To ensure access to drilling rigs, we have entered into fixed-term drilling rig contracts for periods of up to three years and currently have nine drilling rigs under contract. In order to ensure the availability of completion services and the timely fracture stimulation of newly drilled wells, we formed OWS in June 2011 to provide well services on our operated wells, in addition to entering into fracturing service contracts with third party companies.

Third Quarter 2012 Highlights:

- On July 2, 2012, we issued $400 million of 6.875% senior unsecured notes due January 15, 2023, resulting in net proceeds to us of approximately $392 million;
- We completed and placed on production 34 gross operated wells in the Williston Basin during the three months ended September 30, 2012;
- We had 25 gross operated wells awaiting completion and 11 gross operated wells in the process of being drilled in the Bakken and Three Forks formations at September 30, 2012;
- Average daily production was 24,257 Boe per day during the three months ended September 30, 2012;
- Exploration and production (E&P) capital expenditures were $311.4 million, consisting primarily of $275.9 million in drilling expenditures during the three months ended September 30, 2012; and
- At September 30, 2012, we had $406.5 million of cash and cash equivalents and short-term investments and had no borrowings or outstanding letters of credit under our revolving credit facility.

Results of Operations

Revenues

Our revenues are derived from the sale of oil and natural gas production and do not include the effects of derivative instruments. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Table of Contents

The following table summarizes our revenues and production data for the periods indicated.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	Change	2012	2011	Change
Operating results (in thousands):						
Revenues						
Oil	$ 173,752	$ 85,870	$ 87,882	$ 443,686	$ 208,442	$ 235,244
Natural gas	4,996	1,726	3,270	18,171	5,104	13,067
Well services	5,963		5,963	10,484		10,484
Total revenues	184,711	87,596	97,115	472,341	213,546	258,795
Production data:						
Oil (MBbls)	2,076	1,028	1,048	5,232	2,407	2,825
Natural gas (MMcf)	937	225	712	2,740	627	2,113
Oil equivalents (MBoe)	2,232	1,066	1,166	5,688	2,512	3,176
Average daily production (Boe/d)	24,257	11,583	12,674	20,761	9,201	11,560
Average sales prices:						
Oil, without realized derivatives (per Bbl) (1)	$ 83.71	$ 83.52	$ 0.19	$ 84.52	$ 86.58	$ (2.06)
Oil, with realized derivatives (per Bbl) (1) (2)	86.24	83.35	2.89	85.05	84.58	0.47
Natural gas (per Mcf) (3)	5.33	7.66	(2.33)	6.63	8.14	(1.51)

(1) For the nine months ended September 30, 2012, average sales prices for oil are calculated using total oil revenues, excluding bulk purchase sales of $1.5 million, divided by oil production.
(2) Realized prices include realized 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, 2012 as compared to three months ended September 30, 2011

Total revenues. Our total revenues increased $97.1 million, or 111%, to $184.7 million during the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. 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 12,674 Boe per day, or 109%, to 24,257 Boe per day during the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. The increase in average daily production sold was primarily a result of our well completions during the last quarter of 2011 and the first three quarters of 2012. Well completions in our West Williston, East Nesson and Sanish project areas increased average daily production by approximately 9,038 Boe per day, 3,116 Boe per day and 605 Boe per day, respectively, during the third quarter of 2012 as compared to the third quarter of 2011. Average oil sales prices, without realized derivatives, increased by $0.19/Bbl to an average of $83.71/Bbl for the three months ended September 30, 2012 as compared to the three months ended September 30, 2011. The higher production amounts sold increased revenues by $91.4 million, while lower natural gas sales prices, offset by a slight increase in oil prices, decreased revenues by $0.3 million during the three months ended September 30, 2012. The remaining $6.0 million increase in total revenues was attributable to well services revenues during the three months ended September 30, 2012. There were no well services revenues during the third quarter of 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

Nine months ended September 30, 2012 as compared to nine months ended September 30, 2011

Total revenues. Our total revenues increased $258.8 million, or 121%, to $472.3 million during the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. 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 11,560 Boe per day, or 126%, to 20,761 Boe per day during the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. The increase in average daily production sold was primarily a result of our well completions during the last quarter of 2011 and the first three quarters of 2012. Well completions in our West Williston, East Nesson and Sanish project areas increased average daily production by approximately 8,692 Boe per day, 2,379 Boe per day and 587 Boe per day, respectively, during the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. Average oil sales prices, without realized derivatives, decreased by $2.06/Bbl, or 2%, to an average of $84.52/Bbl

for the nine months ended September 30, 2012 as compared to the nine months ended September 30, 2011. The higher production amounts sold increased revenues by $252.7 million, while lower oil and natural gas sales prices decreased revenues by $5.9 million during the nine months ended September 30, 2012. Well services revenues were $10.5 million for the nine months ended September 30, 2012 compared to no well services revenues during the nine months ended September 30, 2011 because OWS did not commence fracturing activity until the first quarter of 2012. The remaining $1.5 million increase in total revenues was attributable to oil bulk purchase revenues related to marketing activities included in oil and gas revenues during the nine months ended September 30, 2012.

Table of Contents

Expenses

The following table summarizes our operating expenses for the periods indicated.

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2012	2011	$ Change	2012	2011	$ Change
	(In thousands, except per Boe of production)					
Expenses:						
Lease operating expenses	$ 16,134	$ 9,597	$ 6,537	$ 37,979	$ 21,178	$ 16,801
Well services operating expenses	5,420		5,420	7,104		7,104
Marketing, transportation and gathering expenses	2,744	238	2,506	7,283	797	6,486
Production taxes	16,433	8,873	7,560	43,419	22,041	21,378
Depreciation, depletion and amortization	57,684	20,859	36,825	140,783	47,771	93,012
Exploration expenses	336	54	282	3,171	345	2,826
Impairment of oil and gas properties	36	396	(360)	2,607	3,313	(706)
General and administrative expenses	13,886	7,306	6,580	39,622	19,870	19,752
Total expenses	112,673	47,323	65,350	281,968	115,315	166,653
Operating income	72,038	40,273	31,765	190,373	98,231	92,142
Other income (expense):						
Net gain (loss) on derivative instruments	(22,441)	71,224	(93,665)	33,568	67,105	(33,537)
Interest expense	(20,979)	(6,786)	(14,193)	(48,952)	(18,745)	(30,207)
Other income	1,147	524	623	2,521	1,215	1,306
Total other income (expense)	(42,273)	64,962	(107,235)	(12,863)	49,575	(62,438)
Income before income taxes	29,765	105,235	(75,470)	177,510	147,806	29,704
Income tax expense	11,451	38,946	(27,495)	66,712	55,015	11,697
Net income	$ 18,314	$ 66,289	$ (47,975)	$ 110,798	$ 92,791	$ 18,007
Cost and expense (per Boe of production):						
Lease operating expenses (1)	$ 7.23	$ 9.00	$ (1.77)	$ 6.68	$ 8.43	$ (1.75)
Marketing, transportation and gathering expenses	1.23	0.23	1.00	1.28	0.32	0.96
Production taxes	7.36	8.33	(0.97)	7.63	8.77	(1.14)
Depreciation, depletion and amortization	25.85	19.57	6.28	24.75	19.02	5.73
General and administrative expenses	6.22	6.86	(0.64)	6.97	7.91	(0.94)

(1) For the three and nine months ended September 30, 2011, lease operating expenses exclude marketing, transportation and gathering expenses to conform such amounts to current year classifications.

Three months ended September 30, 2012 compared to three months ended September 30, 2011

Lease operating expenses. Lease operating expenses increased $6.5 million to $16.1 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. This increase was primarily due to the costs associated with operating an increased number of producing wells. Lease operating expenses decreased from $9.00 per Boe for the three months ended September 30, 2011 to $7.23 per Boe for the three months ended September 30, 2012, primarily due to decreased costs in salt water disposal (SWD), described below. These reductions were partially offset by additional costs related to wells coming on in areas without infrastructure and an increase in non-operated lease operating expenses in the third quarter of 2012.

We have $74 million in our 2012 capital budget primarily allocated to building SWD infrastructure, which is currently being deployed in our key operating areas. This infrastructure is expected to reduce our dependence on trucks for water hauling and simplify operational logistics. As of September 30, 2012, we had approximately 35% of operated water production flowing through our operated pipeline system. We expect to

have approximately 50% of operated water production flowing through the pipeline system by year-end 2012. Additionally, we currently dispose of approximately 60% of our operated water production at our operated disposal wells and expect this to increase to 85% by year-end 2012. This continued expansion of our SWD systems is expected to reduce lease operating expenses related to SWD throughout the remainder of 2012.

Well services operating expenses. The $5.4 million in well services operating expenses represents non-affiliated fracturing service costs incurred by OWS for fracturing jobs completed in the third quarter of 2012. There were no well services operating expenses during the third quarter of 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

Marketing, transportation and gathering expenses. This line item includes all of our marketing, transportation and gathering for our oil production as well as bulk oil purchase costs. The $2.5 million increase quarter over quarter, or $1.00 increase per Boe, is mainly attributable to increased oil transportation costs related to OPM, which did not commence operations until late in the third quarter of 2011.

Table of Contents

Production taxes. Our production taxes for the three months ended September 30, 2012 and 2011 were 9.2% and 10.1%, respectively, as a percentage of oil and natural gas sales. The third quarter 2012 production tax rate was lower than the third quarter 2011 production tax rate primarily due to certain new wells in Montana that are subject to lower incentivized production tax rates.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $36.8 million to $57.7 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. This increase in DD&A expense for the three months ended September 30, 2012 was primarily a result of our production increases from our wells completed during the last quarter of 2011 and the first three quarters of 2012. The DD&A rate for the three months ended September 30, 2012 was $25.85 per Boe compared to $19.57 per Boe for the three months ended September 30, 2011. The higher DD&A rate was a result of the increase in well costs in 2012, which outpaced the increase in associated reserves due to increases in service costs in the Williston Basin throughout the year and the addition of infrastructure assets, primarily our SWD systems.

Impairment of oil and gas properties. During the three months ended September 30, 2012 and 2011, we recorded non-cash impairment charges of $36,000 and $0.4 million, respectively, for unproved property leases that expired during the period or have been forecasted to expire under our current drilling plans. No impairment charges of proved oil and gas properties were recorded for the three months ended September 30, 2012 or 2011.

General and administrative expenses. Our general and administrative (G&A) expenses increased $6.6 million for the three months ended September 30, 2012 from $7.3 million for the three months ended September 30, 2011. Of this increase, approximately $5.1 million related to employee compensation expenses due to our organizational growth and $1.6 million was due to additional amortization of our restricted stock awards and performance share units (PSUs) quarter over quarter. As of September 30, 2012, we had 259 full-time employees compared to 106 full-time employees as of September 30, 2011. Excluding G&A expenses related to OWS, G&A related to E&P on a per Boe basis would still have been $6.22 for the three months ended September 30, 2012.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net gain of $5.2 million for the three months ended September 30, 2012 and a cash settlement net loss of $0.2 million for the three months ended September 30, 2011. In addition, as a result of forward oil price changes, we recognized a $27.7 million non-cash unrealized mark-to-market net derivative loss during the three months ended September 30, 2012 and a $71.4 million non-cash unrealized mark-to-market net derivative gain during the three months ended September 30, 2011.

Interest expense. Interest expense increased $14.2 million to $21.0 million for the three months ended September 30, 2012 compared to the three months ended September 30, 2011. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in November 2011 and July 2012 at an interest rate of 6.5% and 6.875%, respectively. There were no borrowings under our revolving credit facility during the three months ended September 30, 2012 and 2011, respectively. Interest capitalized during the three months ended September 30, 2012 and 2011 was $0.9 million and $1.1 million, respectively.

Income taxes. Income tax expense for the three months ended September 30, 2012 and 2011 was recorded at 38.5% and 37.0% 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, 2012 compared to nine months ended September 30, 2011

Lease operating expenses. Lease operating expenses increased $16.8 million to $38.0 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. This increase was primarily due to the costs associated with operating an increased number of producing wells. Lease operating expenses decreased from $8.43 per Boe for the nine months ended September 30, 2011 to $6.68 per Boe for the nine months ended September 30, 2012, primarily due to decreased costs in SWD. These reductions were partially offset by additional costs related to wells coming on in areas without infrastructure and an increase in non-operated lease operating expenses in 2012.

Well services operating expenses. The $7.1 million in well services operating expenses represents non-affiliated fracturing service costs incurred by OWS for fracturing jobs completed in 2012. There were no well services operating expenses in 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

Marketing, transportation and gathering expenses. This line item includes all of our marketing, transportation and gathering for our oil production as well as bulk oil purchase costs. The $6.5 million increase period over period, or $0.96 increase per Boe, is mainly attributable to increased oil transportation costs related to OPM, which did not commence operations until late in the third quarter of 2011, combined with the $1.4 million cost for bulk oil purchases made by OPM in the first quarter of 2012.

Production taxes. Our production taxes for the nine months ended September 30, 2012 and 2011 were 9.4% and 10.3%, respectively, as a percentage of oil and natural gas sales. The production tax rate for the nine months ended September 30, 2012 was lower than the production tax rate for the nine months ended September 30, 2011 primarily due to certain new wells in Montana that are subject to lower incentivized production tax rates.

Table of Contents

Depreciation, depletion and amortization (DD&A). DD&A expense increased $93.0 million to $140.8 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. This increase in DD&A expense for the nine months ended September 30, 2012 was primarily a result of our production increases from our wells completed during the last quarter of 2011 and the first three quarters of 2012. The DD&A rate for the nine months ended September 30, 2012 was $24.75 per Boe compared to $19.02 per Boe for the nine months ended September 30, 2011. The higher DD&A rate was a result of the increase in well costs in 2012, which outpaced the increase in associated reserves due to increases in service costs in the Williston Basin throughout the year and the addition of infrastructure assets, primarily our SWD systems.

Exploration expenses. The $2.8 million increase in exploration expenses to $3.2 million for the nine months ended September 30, 2012 is primarily due to geological and geophysical costs for the purchase of 3D seismic data during 2012.

Impairment of oil and gas properties. During the nine months ended September 30, 2012 and 2011, we recorded non-cash impairment charges of $2.6 million and $3.3 million, respectively, for unproved property leases that expired during the period or have been forecasted to expire under our current drilling plans. No impairment charges of proved oil and gas properties were recorded for the nine months ended September 30, 2012 or 2011.

General and administrative expenses. Our general and administrative (G&A) expenses increased $19.8 million for the nine months ended September 30, 2012 from $19.9 million for the nine months ended September 30, 2011. Of this increase, approximately $13.8 million related to employee compensation expenses due to our organizational growth and $3.9 million was due to additional amortization of our restricted stock awards and PSUs during the nine months ended September 30, 2012. As of September 30, 2012, we had 259 full-time employees compared to 106 full-time employees as of September 30, 2011. Excluding G&A expenses related to OWS, G&A related to E&P on a per Boe basis would have been $6.49 for the three months ended September 30, 2012.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net gain of $2.8 million for the nine months ended September 30, 2012 and a cash settlement net loss of $4.8 million for the nine months ended September 30, 2011. In addition, as a result of forward oil price changes, we recognized non-cash unrealized mark-to-market net derivative gains during the nine months ended September 30, 2012 and 2011 of $30.8 million and $71.9 million, respectively.

Interest expense. Interest expense increased $30.2 million to $49.0 million for the nine months ended September 30, 2012 compared to the nine months ended September 30, 2011. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in November 2011 and July 2012 at interest rates of 6.5% and 6.875%, respectively. There were no borrowings under our revolving credit facility during the nine months ended September 30, 2012 or 2011. Interest capitalized during the nine months ended September 30, 2012 and 2011 was $2.5 million and $2.1 million, respectively.

Income taxes. Income tax expense for the nine months ended September 30, 2012 and 2011 was recorded at 37.6% and 37.2% 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 have been proceeds from our issuances of senior unsecured notes and cash flows from operations, and historically, proceeds from our IPO in June 2010, borrowings under our revolving credit facility and capital contributions from private investors. Our primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings, 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, 2012 and 2011 are presented below:

	Nine Months Ended September 30,	
	2012	2011
	(In thousands)	
Net cash provided by operating activities	$ 282,128	$ 139,682

Net cash used in investing activities	(863,443)	(509,012)
Net cash provided by financing activities	390,746	389,411
Increase (decrease) in cash and cash equivalents	$ (190,569)	$ 20,081

Table of Contents

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.

Cash flows provided by operating activities

Net cash provided by operating activities was $282.1 million and $139.7 million for the nine months ended September 30, 2012 and 2011, respectively. The increase in cash flows provided by operating activities for the period ended September 30, 2012 as compared to 2011 was primarily the result of an increase in oil and natural gas production of 126%. In addition, at September 30, 2012, we had a working capital surplus of $286.8 million. This surplus was primarily attributable to our cash and cash equivalents balance as a result of the net proceeds from the issuance of our senior unsecured notes in July 2012.

Cash flows used in investing activities

Net cash used in investing activities was $863.4 million and $509.0 million during the nine months ended September 30, 2012 and 2011, respectively. The increase in cash used in investing activities for the nine months ended September 30, 2012 compared to 2011 of $354.4 million was mainly attributable to increased levels of capital expenditures for drilling and development costs.

Our capital expenditures for drilling, development and acquisition costs are summarized in the following table:

	Nine Months Ended September 30, 2012 (In thousands)
Project Area:	
West Williston	$ 581,135
East Nesson	212,630
Sanish	47,804
Total E&P capital expenditures	841,569
Non-E&P capital expenditures (1)	30,693
Total capital expenditures (2)	$ 872,262

(1) Non-E&P capital expenditures include such items as equipment for OWS, district tools, administrative capital and capitalized interest.
(2) 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.

On July 26, 2012, our Board of Directors increased our total 2012 capital expenditure budget from $884 million to $1,062 million, which now consists of:

$912 million of development capital for operated and non-operated wells (including expected savings from services provided by OWS);

$74 million for constructing infrastructure to support production in our core project areas, primarily related to SWD systems that will lower lease operating expenses;

$30 million for maintaining and expanding our leasehold position;

$6 million for micro-seismic work, purchase of seismic data and other test work;

$17 million for OWS, including $12 million for equipment budgeted and ordered in 2011 that arrived in the first quarter of 2012; and

$23 million for other non-E&P capital, including items such as district tools, administrative capital and capitalized interest.

The 2012 capital expenditure budget does not include approximately $30 million of capital that was related to 2011 activity that was included in the first quarter of 2012 actual capital expenditures. While we have budgeted $1,062 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 cash on hand, cash flows from operating activities and availability under our revolving credit facility should be more than sufficient to fund our 2012 capital expenditure budget. However, because the operated wells funded by our 2012 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.

Table of Contents

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 $390.7 million and $389.4 million for the nine months ended September 30, 2012 and 2011, respectively. For the nine months ended September 30, 2012 and 2011, cash sourced through financing activities was primarily provided by the net proceeds from the issuance of our senior unsecured notes in July 2012 and February 2011, respectively. For both the nine months ended September 30, 2012 and 2011, 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 and 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 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 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 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 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 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 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. If a change in control occurs at any time on or prior to January 1, 2013, we may redeem all, but not less than all, of the 2021 Notes, at a redemption price equal to 110% of the principal amount plus accrued and unpaid interest to the redemption date.

On July 2, 2012, we issued $400 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 2021 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 million, which we are using 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 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. If a change in control occurs at any time on or prior to July 15, 2013, we may redeem all, but not less than all, of the 2023 Notes, at a redemption price equal to 110% of the principal amount plus accrued and unpaid interest to the redemption date.

Table of Contents

The indentures governing our 2019 Notes, 2021 Notes and 2023 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 2019 Notes, 2021 Notes or 2023 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 October 2, 2012, we entered into a seventh amendment to our revolving credit facility. In connection with this amendment, the semi-annual redetermination of our borrowing base was completed on October 2, 2012, which resulted in an increase to the borrowing base of our revolving credit facility from $500 million to $750 million. However, we elected to have the lenders aggregate commitment remain at $500 million. This amendment allows us to increase our aggregate commitment from $500 million to $750 million by increasing the commitment of one or more lender(s).

Borrowings under our revolving 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, 2012, we had no borrowings and no outstanding letters of credit under our revolving credit facility. The revolving credit facility also contains certain financial covenants and customary events of default. If an event of default occurs and is continuing, the lenders under our revolving credit facility may declare all amounts outstanding under our revolving credit facility to be immediately due and payable. As of September 30, 2012, we were in compliance with the financial covenants of our revolving 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, 2012 (in thousands):

Contractual Obligations	Total	Within 1Year	2-3 Years	4-5 Years	More Than 5 Years
Operating leases (1)	$ 14,017	$ 2,766	$ 5,578	$ 5,673	$
Drilling rig commitments (1)	50,417	25,115	25,302		
Volume commitment agreements (1)	75,388	3,503	25,767	31,489	14,629
Senior unsecured notes (2)	1,200,000				1,200,000
Interest payments on senior unsecured notes (2)	725,243	83,493	165,000	165,000	311,750
Asset retirement obligations (3)	20,807	277	1,736	357	18,437
Total	$ 2,085,872	$ 115,154	$ 223,383	$ 202,519	$ 1,544,816

(1) See Note 12 to our unaudited condensed consolidated financial statements for a description of our operating leases, drilling rig commitments and volume commitment agreements.

(2) See Note 7 to our unaudited condensed consolidated financial statements for a description of our senior unsecured notes. As of September 30, 2012, we had no indebtedness outstanding under our 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.

Table of Contents

Critical Accounting Policies and Estimates

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2011 Annual Report other than those noted below.

Stock-Based Compensation Performance Share Units

We recognize compensation expense for our PSUs granted to our officers. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the performance period, which is generally the vesting period. The fair value of the PSUs is based on the calculation derived from a Monte Carlo simulation model. The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probable assessment. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the stock-based compensation expense recognized. Stock-based compensation expense recorded for PSUs is included in general and administrative expenses on our Condensed Consolidated Statement of Operations.

Recent Accounting Pronouncements

Intangible assets. In July 2012, the Financial Accounting Standards Board issued Accounting Standards Update No. 2012-02, *Intangibles Goodwill and Other Testing Indefinite-Lived Intangible Assets for Impairment* (ASU 2012-02). The objective of ASU 2012-02 is to reduce the cost and complexity of performing an impairment test for indefinite-lived intangible assets by permitting an entity first to assess qualitative factors to determine whether it is more likely than not that an indefinite-lived intangible asset is impaired, as a basis for determining whether it is necessary to perform a quantitative impairment test. ASU 2012-02 is effective for interim and annual reporting periods beginning after September 15, 2012. We do not expect the adoption of this new guidance to have any impact on our financial position, cash flows or results of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the 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 GAAP. See Note 12 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 2011 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, 2012, we utilized two-way and three-way collar options, swaps and put spreads 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 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).

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, 2012:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Average Swap Price	Average Sub-Floor Price	Average Floor Price	Average Ceiling Price	Fair Value Asset (Liability) (In thousands)
2012	Two-Way Collars	819,000			$ 88.61	$ 105.59	$ 975
2012	Three-Way Collars	910,000		$ 66.25	$ 90.25	$ 110.04	841
2012	Swaps	91,000	$ 94.61				130
2013	Two-Way Collars	1,782,000			$ 86.50	$ 98.93	(1,164)
2013	Three-Way Collars	2,023,420		$ 65.30	$ 92.51	$ 112.63	8,561
2013	Put Spreads	1,717,080		$ 70.71	$ 91.24		9,931
2013	Swaps	699,000	$ 96.41				1,850
2014	Two-Way Collars	139,500			$ 86.11	$ 97.69	(84)
2014	Three-Way Collars	1,495,030		$ 70.60	$ 91.43	$ 110.30	3,229
2014	Put Spreads	150,970		$ 71.03	$ 91.03		1,019
2014	Swaps	62,000	$ 96.49				215
2015	Three-Way Collars	124,000		$ 71.25	$ 91.25	$ 109.96	231
							$ 25,734

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) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum outstanding at September 30, 2012. During the first nine months of 2012, we had no indebtedness outstanding under our revolving credit facility. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issued under our revolving 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 revolving credit facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the hedged volumes placed under individual contracts.

Table of Contents

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 $141.2 million at September 30, 2012.

Most of the counterparties on our derivative instruments currently in place are lenders under our revolving credit facility with investment grade ratings. We are likely to enter into any future derivative instruments with these or other lenders under our revolving 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 asset position of $25.7 million at September 30, 2012.

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, 2012. 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 the evaluation, our CEO, CFO and CAO have concluded that our disclosure controls and procedures were effective at September 30, 2012.

Changes in internal control over financial reporting. During the quarter ended June 30, 2012, we converted to a new accounting and land software system, which replaced our existing system. We took the necessary steps to monitor and maintain appropriate internal controls during this period of change. These steps included procedures to preserve the integrity of the data converted and a review by management to validate the data converted. Additionally, we provided training related to this system to individuals using the system to carry out their job responsibilities. We anticipate that the implementation of this software will strengthen the overall system of internal controls due to enhanced automation and integration of related processes. The system change was undertaken to integrate systems and consolidate information and was not undertaken in response to any actual or perceived deficiencies in our internal control over financial reporting. In conjunction with this system conversion, we also brought all of our outsourced accounting functions in-house.

During the quarter ended September 30, 2012, we completed the design and documentation of internal control processes and procedures relating to the new system and modules to supplement and complement existing internal control over certain respective job areas. Testing of the controls related to the new system and accounting functions is ongoing and is included in the scope of our assessment of our 2012 internal control over financial reporting, which will be completed in conjunction with the filing of our annual report on Form 10-K for the year ended December 31, 2012.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

Table of Contents

PART II OTHER INFORMATION

Item 1. Legal Proceedings

See Part I, Item 1, Note 12 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.

There have been no material changes in our risk factors from those described in our Annual Report on Form 10-K for the year ended December 31, 2011 and our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012. For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our 2011 Annual Report and our Quarterly Report on Form 10-Q for the quarterly period ended March 31, 2012.

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, 2012:

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, 2012	1,583	$ 26.14		
August 1 August 31, 2012	1,168	26.12		
September 1 September 30, 2012	704	29.60		
Total	3,455	$ 26.84		

(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 common stock.

Table of Contents

Item 6. Exhibits

Exhibit No.	Description of Exhibit
4.1	Second Supplemental Indenture dated as of July 2, 2012 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 July 2, 2012, and incorporated herein by reference).
10.1	Form of Notice of Grant of Performance Share Units (filed as Exhibit 10.1 to the Company s Current Report on Form 8-K filed on August 3, 2012, and incorporated herein by reference).
10.2	Form of Performance Share Unit Agreement (filed as Exhibit 10.2 to the Company s Current Report on Form 8-K filed on August 3, 2012, and incorporated herein by reference).
10.3	Seventh Amendment to Amended and Restated Credit Agreement, dated as of October 2, 2012, among Oasis Petroleum North America, as borrower, Oasis Petroleum LLC, Oasis Petroleum Marketing LLC, Oasis Well Services LLC and Oasis Petroleum Inc., as guarantors, 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 October 4, 2012, 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 8, 2012

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)

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(b) Furnished herewith.