Oasis Petroleum Inc.
Form 10-Q
August 06, 2014
Table of Contents

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

FORM 10-Q

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

For the quarterly period ended June 30, 2014

or

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

For the transition period from to

Commission file number: 1-34776

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

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

(281) 404-9500
(Registrant's telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

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

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

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

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

Number of shares of the registrant's common stock outstanding at August 1, 2014: 101,153,956 shares.

Table of Contents

OASIS PETROLEUM INC.
FORM 10-Q
FOR THE QUARTER ENDED JUNE 30, 2014
TABLE OF CONTENTS

	Page
PART I — FINANCIAL INFORMATION	1
Item 1. — Financial Statements (Unaudited)	1
Condensed Consolidated Balance Sheet at June 30, 2014 and December 31, 2013	1
Condensed Consolidated Statement of Operations for the Three and Six Months Ended June 30, 2014 and 2013	2
Condensed Consolidated Statement of Changes in Stockholders’ Equity for the Six Months Ended June 30, 2014	3
Condensed Consolidated Statement of Cash Flows for the Six Months Ended June 30, 2014 and 2013	4
Notes to Condensed Consolidated Financial Statements	5
Item 2. — Management’s Discussion and Analysis of Financial Condition and Results of Operations	22
Item 3. — Quantitative and Qualitative Disclosures About Market Risk	36
Item 4. — Controls and Procedures	37
PART II — OTHER INFORMATION	38
Item 1. — Legal Proceedings	38
Item 1A. — Risk Factors	38
Item 2. — Unregistered Sales of Equity Securities and Use of Proceeds	38
Item 6. — Exhibits	38
SIGNATURES	40
EXHIBIT INDEX	41

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

	June 30, 2014	December 31, 2013
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$26,957	$91,901
Accounts receivable — oil and gas revenues	216,764	175,653
Accounts receivable — joint interest partners	147,056	139,459
Inventory	17,636	20,652
Prepaid expenses	8,907	10,191
Deferred income taxes	25,390	6,335
Derivative instruments	—	2,264
Advances to joint interest partners	97	760
Other current assets	421	391
Total current assets	443,228	447,606
Property, plant and equipment		
Oil and gas properties (successful efforts method)	5,141,582	4,528,958
Other property and equipment	231,129	188,468
Less: accumulated depreciation, depletion, amortization and impairment	(823,500)	(637,676)
Total property, plant and equipment, net	4,549,211	4,079,750
Assets held for sale	—	137,066
Derivative instruments	—	1,333
Deferred costs and other assets	44,540	46,169
Total assets	$5,036,979	$4,711,924
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$32,402	$8,920
Revenues and production taxes payable	217,414	146,741
Accrued liabilities	288,813	241,830
Accrued interest payable	49,444	47,910
Derivative instruments	62,415	8,188
Advances from joint interest partners	6,910	12,829
Other current liabilities	3,311	—
Total current liabilities	660,709	466,418
Long-term debt	2,300,000	2,535,570
Deferred income taxes	460,897	323,147
Asset retirement obligations	37,542	35,918
Derivative instruments	11,844	139
Other liabilities	1,963	2,183
Total liabilities	3,472,955	3,363,375
Commitments and contingencies (Note 14)		
Stockholders' equity		
Common stock, $0.01 par value: 300,000,000 shares authorized; 101,396,597 and 100,866,589 shares issued at June 30, 2014 and December 31, 2013, respectively	999	996

Treasury stock, at cost: 244,729 and 167,155 shares at June 30, 2014 and December 31, 2013, respectively	(8,677)	(5,362)
Additional paid-in capital	995,024	985,023
Retained earnings	576,678	367,892
Total stockholders' equity	1,564,024	1,348,549
Total liabilities and stockholders' equity	$5,036,979	$4,711,924

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

1

Table of Contents

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$354,182	$241,842	$686,029	$483,493
Well services and midstream revenues	18,196	12,740	35,868	19,393
Total revenues	372,378	254,582	721,897	502,886
Expenses				
Lease operating expenses	40,553	18,266	80,542	37,755
Well services and midstream operating expenses	8,769	6,644	19,689	9,558
Marketing, transportation and gathering expenses	7,114	10,779	12,300	14,168
Production taxes	34,493	21,397	66,296	43,486
Depreciation, depletion and amortization	97,276	66,790	188,548	133,051
Exploration expenses	475	392	855	2,249
Impairment of oil and gas properties	42	208	804	706
General and administrative expenses	20,751	16,656	44,271	30,510
Total expenses	209,473	141,132	413,305	271,483
Gain on sale of properties	3,640	—	187,033	—
Operating income	166,545	113,450	495,625	231,403
Other income (expense)				
Net gain (loss) on derivative instruments	(65,570)	12,591	(83,173)	(2,021)
Interest expense, net of capitalized interest	(38,990)	(21,392)	(79,148)	(42,575)
Other income (expense)	135	294	288	1,074
Total other income (expense)	(104,425)	(8,507)	(162,033)	(43,522)
Income before income taxes	62,120	104,943	333,592	187,881
Income tax expense	23,287	37,824	124,806	68,911
Net income	$38,833	$67,119	$208,786	$118,970
Earnings per share:				
Basic (Note 12)	$0.39	$0.73	$2.10	$1.29
Diluted (Note 12)	0.39	0.72	2.08	1.28
Weighted average shares outstanding:				
Basic (Note 12)	99,663	92,399	99,612	92,387
Diluted (Note 12)	100,260	92,702	100,328	92,812

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

Table of Contents

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
Balance as of December 31, 2013	100,699	$996	167	$(5,362)	$985,023	$367,892	$1,348,549
Fees (2013 issuance of common stock)	—	—	—	—	(176)	—	(176)
Stock-based compensation	531	—	—	—	10,180	—	10,180
Vesting of restricted shares	—	3	—	—	(3)	—	—
Treasury stock – tax withholdings	(78)	—	78	(3,315)	—	—	(3,315)
Net income	—	—	—	—	—	208,786	208,786
Balance as of June 30, 2014	101,152	$999	245	$(8,677)	$995,024	$576,678	$1,564,024

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)

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Cash flows from operating activities:		
Net income	$208,786	$118,970
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	188,548	133,051
Gain on sale of properties	(187,033)	—
Impairment of oil and gas properties	804	706
Deferred income taxes	118,695	67,974
Derivative instruments	83,173	2,021
Stock-based compensation expenses	9,678	5,371
Debt discount amortization and other	3,220	1,753
Working capital and other changes:		
Change in accounts receivable	(37,132)	(13,768)
Change in inventory	3,016	(4,200)
Change in prepaid expenses	1,284	(4,402)
Change in other current assets	(30)	330
Change in other assets	(1,477)	—
Change in accounts payable and accrued liabilities	91,543	48,701
Change in other current liabilities	3,311	688
Change in other liabilities	(132)	612
Net cash provided by operating activities	486,254	357,807
Cash flows from investing activities:		
Capital expenditures	(606,924)	(428,630)
Acquisition of oil and gas properties	(8,116)	—
Proceeds from sale of properties	324,888	—
Costs related to sale of properties	(2,337)	—
Redemptions of short-term investments	—	25,000
Derivative settlements	(13,644)	2,932
Advances from joint interest partners	(5,919)	(5,593)
Net cash used in investing activities	(312,052)	(406,291)
Cash flows from financing activities:		
Proceeds from revolving credit facility	100,000	—
Principal payments on revolving credit facility	(335,570)	—
Purchases of treasury stock	(3,315)	(364)
Debt issuance costs	(85)	(2,998)
Other	(176)	—
Net cash used in financing activities	(239,146)	(3,362)
Decrease in cash and cash equivalents	(64,944)	(51,846)
Cash and cash equivalents:		
Beginning of period	91,901	213,447
End of period	$26,957	$161,601
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$51,129	$(6,085)

Change in asset retirement obligations	1,624	3,441

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. (together with its subsidiaries, "Oasis" or the "Company") was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a holding company for Oasis Petroleum LLC ("OP LLC"), the Company's predecessor, which was formed as a Delaware limited liability company on February 26, 2007. In connection with its initial public offering in June 2010 and related corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company's common stock. In 2007, Oasis Petroleum North America LLC ("OPNA"), a Delaware limited liability company, was formed to conduct domestic oil and natural gas exploration and production activities. In 2011, the Company formed Oasis Well Services LLC ("OWS"), a Delaware limited liability company, to provide well services to OPNA, and Oasis Petroleum Marketing LLC ("OPM"), a Delaware limited liability company, to provide marketing services to OPNA. In 2013, the Company formed Oasis Midstream Services LLC ("OMS"), a Delaware limited liability company, to provide midstream services to OPNA. As part of the formation of OMS, the Company transferred substantially all of its salt water disposal and other midstream assets from OPNA to OMS.

Nature of Business

The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the Williston Basin. The Company's proved and unproved oil and natural gas properties are located in the North Dakota and Montana areas of the Williston Basin and are owned by OPNA. The Company also operates a marketing business (OPM), a well services business (OWS) and a midstream services business (OMS), all of which are complementary to its primary development and production activities. Both OWS and OMS are separate reportable business segments.

2. Summary of Significant Accounting Policies

Basis of Presentation

The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. 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, 2013 is derived from audited financial statements. 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. 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, 2013 ("2013 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 2013 Annual Report other than those noted below.

Recent Accounting Pronouncements

Revenue recognition. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers ("ASU 2014-09"). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP and is effective for interim and annual reporting periods beginning after December 15, 2016. The Company is currently evaluating the effect that adopting this new guidance will have on its financial position, cash flows and results of operations.

Table of Contents

3. Inventory

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

	June 30, 2014	December 31, 2013
	(In thousands)	
Equipment and materials	$7,222	$11,669
Crude oil inventory	10,414	8,983
Total inventory	$17,636	$20,652

4. Property, Plant and Equipment

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

	June 30, 2014	December 31, 2013
	(In thousands)	
Proved oil and gas properties[1]	$4,305,827	$3,713,525
Less: Accumulated depreciation, depletion, amortization and impairment	(787,418)	(612,380)
Proved oil and gas properties, net	3,518,409	3,101,145
Unproved oil and gas properties	835,755	815,433
Total oil and gas properties, net	4,354,164	3,916,578
Other property and equipment	231,129	188,468
Less: Accumulated depreciation	(36,082)	(25,296)
Other property and equipment, net	195,047	163,172
Total property, plant and equipment, net	$4,549,211	$4,079,750

(1) Included in the Company’s proved oil and gas properties are estimates of future asset retirement costs of $33.4 million and $32.6 million at June 30, 2014 and December 31, 2013, 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 natural gas properties of $42,000 and $0.8 million for the three and six months ended June 30, 2014, respectively, and $0.2 million and $0.7 million for the three and six months ended June 30, 2013, respectively. No impairment charges on proved oil and natural gas properties were recorded for the three and six months ended June 30, 2014 or 2013.

5. Divestiture

On March 5, 2014, the Company completed the sale of certain non-operated properties in its Sanish project area and other non-operated leases adjacent to its Sanish position (the “Sanish Divestiture”) for cash proceeds of approximately $324.9 million, which includes, and is subject to further, customary post close adjustments. The Company recognized a $187.0 million gain on sale of properties in its Condensed Consolidated Statement of Operations for the six months ended June 30, 2014. The transaction was structured as an Internal Revenue Code Section 1031 like-kind exchange for tax purposes and as such did not give rise to any currently taxable gain.

6. 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 (“ARO”) and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

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

6

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 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 June 30, 2014			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$742	$—	$—	$742
Total assets	$742	$—	$—	$742
Liabilities:				
Commodity derivative instruments (see Note 7)	$—	$74,259	$—	$74,259
Total liabilities	$—	$74,259	$—	$74,259

	At fair value as of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$742	$—	$—	$742
Commodity derivative instruments (see Note 7)	—	3,597	—	3,597
Total assets	$742	$3,597	$—	$4,339
Liabilities:				
Commodity derivative instruments (see Note 7)	$—	$8,327	$—	$8,327
Total liabilities	$—	$8,327	$—	$8,327

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 June 30, 2014 and December 31, 2013. 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 because the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include oil collars, swaps and deferred premium puts. The fair values of the Company's commodity derivative instruments are based upon

7

a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The Company compares the third-party preparer's valuation to counterparty valuation statements, investigating any significant differences, and analyzes monthly valuation changes in relation to movements in crude oil forward price curves. The determination of the fair value for derivative instruments also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculates the credit adjustment for derivatives in a net asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a net liability position is based on the Company's market credit spread. Based on these calculations, the Company recorded an adjustment to reduce the fair value of its net derivative liability by $2.5 million and $0.2 million at June 30, 2014 and December 31, 2013, respectively.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At June 30, 2014, the Company's cash equivalents were all Level 1 assets. The carrying amount of the Company's long-term debt reported in the Condensed Consolidated Balance Sheet at June 30, 2014 is $2,300.0 million, which includes $2,200.0 million of senior unsecured notes and $100.0 million of borrowings under the revolving credit facility (see Note 8 – Long-Term Debt). The fair value of the Company's senior unsecured notes, which are Level 1 liabilities, is $2,380.0 million at June 30, 2014.

Nonfinancial Assets and Liabilities

Asset retirement obligations. The carrying amount of the Company's ARO in the Condensed Consolidated Balance Sheet at June 30, 2014 is $38.1 million (see Note 9 – Asset Retirement Obligations). The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments, including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Impairment. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs. No impairment charges on proved oil and natural gas properties were recorded for the three and six months ended June 30, 2014 or 2013.

7. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of June 30, 2014, the Company utilized two-way and three-way costless collar options, swaps, swaps with sub-floors and deferred premium puts to reduce the volatility of oil prices on a significant portion of its future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX West Texas Intermediate ("WTI") crude oil index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A swap with a sub-floor is a swap coupled with a

Table of Contents

sold put (sub-floor) at which point the minimum price would be WTI crude oil index price plus the difference between the swap and the sold put strike price. For the deferred premium puts, the Company agrees to pay a premium to the counterparty at the time of settlement. At settlement, if the WTI price is below the floor price of the put, the Company receives the difference between the floor price and the WTI price multiplied by the contract volumes, less the premium. If the WTI price settles at or above the floor price of the put, the Company pays only the premium.

All derivative instruments are recorded on the Company's Condensed Consolidated Balance Sheet as either assets or liabilities measured at fair value (see Note 6 – Fair Value Measurements). 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 are recognized in the other income (expense) section of the Company's Condensed Consolidated Statement of Operations as a net gain or loss on derivative instruments. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making a payment to or receiving a payment from the counterparty. These cash settlements are reflected as investing activities in the Company's Condensed Consolidated Statement of Cash Flows.

As of June 30, 2014, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the average WTI crude oil index price:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices				Weighted Average Deferred Premium	Fair Value Asset (Liability)
			Swap	Sub-Floor	Floor	Ceiling		
		(Barrels)	($/Barrel)					(In thousands)
2014	Two-way collars	1,855,500			$94.92	$106.16		$ (3,019)
2014	Three-way collars	1,615,500		$70.57	$90.57	$105.20		(3,774)
2014	Swaps	1,858,500	$96.13					(14,339)
2014	Swaps with sub-floors	1,098,000	$92.60	$70.00				(12,194)
2015	Two-way collars	2,388,500			$87.98	$103.21		(2,738)
2015	Three-way collars	263,500		$70.59	$90.59	$105.25		(489)
2015	Swaps	5,263,500	$90.81					(34,657)
2015	Swaps with sub-floors	186,000	$92.60	$70.00				(1,544)
2015	Deferred premium puts	1,086,000			$90.00		$2.55	(549)
2016	Two-way collars	155,000			$86.00	$103.42		92
2016	Swaps	310,000	$90.15					(1,048)
								$ (74,259)

The following table summarizes the location and fair value of all outstanding commodity derivative instruments recorded in the Company's Condensed Consolidated Balance Sheet for the periods presented:

Fair Value of Derivative Instrument Assets (Liabilities)

Commodity	Balance Sheet Location	Fair Value	
		June 30, 2014	December 31, 2013
		(In thousands)	
Crude oil	Derivative instruments — current assets	$—	$2,264
Crude oil	Derivative instruments — non-current assets	—	1,333
Crude oil	Derivative instruments — current liabilities	(62,415)	(8,188)
Crude oil	Derivative instruments — non-current liabilities	(11,844)	(139)
Total derivative instruments		$(74,259)	$(4,730)

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

Table of Contents

	Statement of Operations Location	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
		(In thousands)			
Non-cash change in fair value of derivative instruments	Net gain (loss) on derivative instruments	$(54,165)	$11,345	$(69,529)	$(4,953)
Derivative settlements	Net gain (loss) on derivative instruments	(11,405)	1,246	(13,644)	2,932
Total net gain (loss) on derivative instruments		$(65,570)	$12,591	$(83,173)	$(2,021)

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

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

Offsetting of Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
	(In thousands)		
As of June 30, 2014	$22,988	$(22,988)	$ —
As of December 31, 2013	22,743	(19,146)	3,597

Offsetting of Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet
	(In thousands)		
As of June 30, 2014	$97,247	$(22,988)	$ 74,259
As of December 31, 2013	27,473	(19,146)	8,327

8. Long-Term Debt

Senior unsecured notes. On September 24, 2013, the Company issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the "2022 Notes"). The issuance of the 2022 Notes resulted in aggregate net proceeds to the Company of $983.6 million. The Company used the proceeds from the 2022 Notes to fund the acquisition of oil and gas properties in its West Williston project area. On June 30, 2014, the Company filed a registration statement on Form S-4 with the SEC to allow the holders of the 2022 Notes to exchange the 2022 Notes for the same principal amount of a new issue of notes with substantially identical terms, except the new notes will be freely transferable under the Securities Act. The Company will use commercially reasonable efforts to cause the exchange to be completed within 360 days after the 2022 Notes issuance date. Under certain circumstances, in lieu of a registered exchange offer, the Company must use commercially reasonable efforts to file a shelf registration statement for the resale of the 2022 Notes. If the Company fails to satisfy these obligations on a timely basis, the annual interest borne by the 2022 Notes will be increased by 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective. The Company estimates the value of this contingent interest is immaterial at June 30, 2014 and December 31, 2013.

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

The Notes were issued under indentures containing provisions that are substantially the same, as amended and supplemented by supplemental indentures (collectively the “Indentures”), among the Company, along with its material subsidiaries (the “Guarantors”), and U.S. Bank National Association, as trustee (the “Trustee”). The Notes are guaranteed on a senior unsecured basis by the Company’s Guarantors. These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions, as follows:

Table of Contents

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

The Company has certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The Company estimates that the fair value of these redemption options is immaterial at June 30, 2014 and December 31, 2013.

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

The Indentures contain customary events of default, including:

- default in any payment of interest on any Note when due, continued for 30 days;
- default in the payment of principal or premium, if any, on any Note when due;
- 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 in the aggregate principal amount of $10.0 million or more;
- certain events of bankruptcy, insolvency or reorganization of the Company or a Significant Subsidiary (as defined in the Indentures) or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary;
- failure by the Company or any Significant Subsidiary or group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary to pay certain final judgments aggregating in excess of $10.0 million within 60 days; and
- any guarantee of the Notes by a Guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker.

Senior secured revolving line of credit. On April 5, 2013, the Company, as parent, and OPNA, as borrower, entered into a second amended and restated credit agreement (the "Second Amended Credit Facility"), which has a maturity date of April 5, 2018. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On March 27, 2014, the lenders under the Second Amended Credit Facility (the "Lenders") completed their regular semi-annual redetermination of the borrowing base, resulting in an increase to the borrowing base from $1,500.0 million to $1,750.0 million. However, the Company elected to limit the Lenders' aggregate commitment to $1,500.0 million. The overall senior secured line of credit under the Second Amended Credit Facility is $2,500.0 million as of June 30, 2014.

Table of Contents

Borrowings under the Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

Borrowings under the Second Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate ("LIBOR") loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or "ABR" loan). As of June 30, 2014, any outstanding LIBOR and ABR loans bore their respective interest rates plus the applicable margin indicated in the following table:

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

An ABR loan may be repaid at any time before the scheduled maturity of the Second Amended Credit Facility upon the Company providing advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms greater than three months in duration. At the end of a LIBOR loan term, the Second Amended Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or a differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company pays a 0.375% (as of June 30, 2014) 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 June 30, 2014, the Second Amended Credit Facility contained covenants that included, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on the assets of the Company and its subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;
- a requirement that the Company maintain a ratio of consolidated EBITDAX (as defined in the Second Amended Credit Facility) to consolidated Interest Expense (as defined in the Second Amended Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that the Company maintain a Current Ratio (as defined in the Second Amended Credit Facility) of consolidated current assets (including unused borrowing base capacity and with exclusions as described in the Second Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Second Amended Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter.

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

12

Table of Contents

As of June 30, 2014, the Company had $100.0 million of LIBOR loans and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base capacity of $1,394.8 million. As of June 30, 2014, the weighted average interest rate was 1.7% on borrowings outstanding under the Second Amended Credit Facility. The Company was in compliance with the financial covenants of the Second Amended Credit Facility as of June 30, 2014.

Deferred financing costs. As of June 30, 2014, the Company had $38.7 million of deferred financing costs related to the Notes and the Second Amended Credit Facility. The deferred financing costs are included in deferred costs and other assets on the Company's Condensed Consolidated Balance Sheet at June 30, 2014 and are being amortized over the respective terms of the Notes and the Second Amended Credit Facility. Amortization of deferred financing costs recorded for the three and six months ended June 30, 2014 was $1.6 million and $3.2 million, respectively, and $1.0 million and $1.9 million for the three and six months ended June 30, 2013, respectively. These costs are included in interest expense on the Company's Condensed Consolidated Statement of Operations.

9. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the six months ended June 30, 2014:

	(In thousands)
Balance at December 31, 2013	$36,458
Liabilities incurred during period	2,689
Liabilities settled during period[1]	(1,974)
Accretion expense during period[2]	909
Balance at June 30, 2014	$38,082

(1) Liabilities settled during period represents ARO related to the properties sold in the Sanish Divestiture.

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

At June 30, 2014, the current portion of the total ARO balance was approximately $0.5 million and is included in accrued liabilities on the Company's Condensed Consolidated Balance Sheet.

10. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the value of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. For the six months ended June 30, 2014, the Company assumed annual forfeiture rates by employee group ranging from 0% to 12.7% based on the Company's forfeiture history for this type of award.

During the six months ended June 30, 2014, employees and non-employee directors of the Company were granted restricted stock awards equal to 621,770 shares of common stock with a $42.67 weighted average grant date per share value. Stock-based compensation expense recorded for restricted stock awards for the three and six months ended June 30, 2014 was $4.3 million and $8.2 million, respectively, and was $2.6 million and $4.6 million for three and six months ended June 30, 2013, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

Performance share units. The Company has granted performance share units ("PSUs") to officers of the Company under its Amended and Restated 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. For the six months ended June 30, 2014, the Company assumed an annual forfeiture rate of 3.3% based on the Company's forfeiture history for the officer employee group receiving PSUs.

During the six months ended June 30, 2014, officers of the Company were granted 158,970 PSUs with a $41.71 weighted average grant date per share value. Stock-based compensation expense recorded for PSUs for the three and six months ended June 30, 2014 was $0.9 million and $1.5 million, respectively, and is included in general and administrative expenses on the Condensed Consolidated Statement of Operations. Stock-based compensation expense recorded for PSUs for the three and six months ended June 30, 2013 was $0.5 million and $0.8 million, respectively.

13

Table of Contents

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

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

The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions for the Monte Carlo model are the forecast period, initial value, risk-free interest rate, volatility and correlation coefficients. The risk-free interest rate is the U.S. treasury bond rate on the date of grant that corresponds to the extended performance period. 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.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the PSUs granted during the six months ended June 30, 2014:

Forecast period (years)	4.00	
Risk-free interest rate	1.12	%
Oasis stock price volatility	44.49	%

Based on these assumptions, the Monte Carlo simulation model resulted in an expected percentage of PSUs earned of 98% for the PSUs granted during the six months ended June 30, 2014.

11. Income Taxes

The Company's effective tax rate for the three and six months ended June 30, 2014 was 37.5% and 37.4%, respectively. The Company's effective tax rate for the three and six months ended June 30, 2013 was 36.0% and 36.7%, 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 June 30, 2014, 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 June 30, 2014 recorded in 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 June 30, 2014, management determined that a valuation allowance was not required for the tax loss carryforwards as they are expected to be fully utilized before expiration.

12. 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.

Table of Contents

The following is a calculation of the basic and diluted weighted-average shares outstanding for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Basic weighted average common shares outstanding	99,663	92,399	99,612	92,387
Dilution effect of stock awards at end of period	597	303	716	425
Diluted weighted average common shares outstanding	100,260	92,702	100,328	92,812
Anti-dilutive stock-based compensation awards	1,115	914	909	711

Issuance of common stock. On December 9, 2013, the Company completed a public offering of 7,000,000 shares of its common stock, par value $0.01 per share, at an offering price of $44.94 per share. Net proceeds from the offering were $314.4 million, after deducting offering expenses, of which $70,000 is included in common stock and $314.3 million is included in additional paid-in capital on the Company’s Consolidated Balance Sheet. The Company used the net proceeds to repay outstanding indebtedness under its Second Amended Credit Facility, to fund its exploration, development and acquisition program and for general corporate purposes.

13. Business Segment Information

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

Table of Contents

	Exploration and Production	Well Services	Midstream Services	Consolidated
	(In thousands)			
Three months ended June 30, 2014:				
Revenues	$354,183	$58,447	$13,478	$426,108
Inter-segment revenues	—	(43,570)	(10,160)	(53,730)
Total revenues	354,183	14,877	3,318	372,378
Operating income	158,353	6,858	1,334	166,545
Other income (expense)	(104,448)	23	—	(104,425)
Income before income taxes	53,905	6,881	1,334	62,120
Three months ended June 30, 2013:				
Revenues	$241,842	$31,382	$7,035	$280,259
Inter-segment revenues	—	(19,921)	(5,756)	(25,677)
Total revenues	241,842	11,461	1,279	254,582
Operating income	105,459	3,310	4,681	113,450
Other income (expense)	(8,511)	4	—	(8,507)
Income before income taxes	96,948	3,314	4,681	104,943
Six months ended June 30, 2014:				
Revenues	$686,030	$110,853	$22,831	$819,714
Inter-segment revenues	—	(80,149)	(17,668)	(97,817)
Total revenues	686,030	30,704	5,163	721,897
Operating income	484,886	8,478	2,261	495,625
Other income (expense)	(162,108)	75	—	(162,033)
Income before income taxes	322,778	8,553	2,261	333,592
Six months ended June 30, 2013:				
Revenues	$483,493	$67,150	$11,855	$562,498
Inter-segment revenues	—	(49,975)	(9,637)	(59,612)
Total revenues	483,493	17,175	2,218	502,886
Operating income	218,357	5,873	7,173	231,403
Other income (expense)	(43,530)	8	—	(43,522)
Income before income taxes	174,827	5,881	7,173	187,881
Total assets:				
As of June 30, 2014	$4,844,196	$77,050	$115,733	$5,036,979
As of December 31, 2013	4,532,264	70,708	108,952	4,711,924

14. Commitments and Contingencies

Lease obligations. The Company’s total rental commitments under leases for office space and other property and equipment at June 30, 2014 were $27.4 million.

Drilling contracts. As of June 30, 2014, the Company had certain drilling rig contracts with initial terms greater than one year. In the event of early termination under these contracts, the Company would be obligated to pay approximately $35.0 million as of June 30, 2014 for the days remaining through the end of the primary terms of the contracts.

Volume commitment agreements. As of June 30, 2014, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 35.7 MMBbl and 10.4 Bcf from its Williston Basin project areas within specified timeframes, all of which are less than ten years. Future obligations under these agreements were approximately $179.8 million as of June 30, 2014.

Table of Contents

Water purchase agreements. As of June 30, 2014, the Company had certain agreements for the purchase of freshwater with an aggregate future obligation of approximately $4.2 million.

Cost sharing agreements. As of June 30, 2014, the Company had certain agreements to share the cost to construct and install electrical facilities. The Company's estimated future obligation under these agreements was $11.1 million as of June 30, 2014.

Investment commitment. As of June 30, 2014, the Company had a remaining capital spending commitment of $7.0 million in connection with drilling and completion activities that the Company agreed to fund for certain wells that were part of the Company's acquisitions of oil and natural gas properties in its East Nesson project area during the third quarter of 2013.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, the Company believes that 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. When the Company determines that a loss is probable of occurring and is reasonably estimable, the Company accrues an undiscounted liability for such contingencies based on its best estimate using information available at the time. The Company discloses contingencies where an adverse outcome may be material, or in the judgment of management, the matter should otherwise be disclosed.

On July 6, 2013, a freight train operated by Montreal, Maine and Atlantic Railway ("MMA") carrying crude oil (the "Train") derailed in Lac-Mégantic, Quebec. In March 2014, Oasis Petroleum Inc. and OP LLC were added to a group of over fifty named defendants, including other crude oil producers as well as the Canadian Pacific Railway, MMA and certain of its affiliates, owners and transloaders of the crude oil carried by the Train, several lessors of tank cars, and the Attorney General of Canada, in a motion filed in Quebec Superior Court to authorize a class-action lawsuit seeking economic, compensatory and punitive damages, as well as costs for claims arising out of the derailment of the Train (Yannick Gagne, etc., et al. v. Rail World, Inc., etc., et al., Case No. 48006000001132). The motion generally alleges wrongful death and negligence in the failure to provide for the proper and safe transportation of crude oil.

The Company believes that all claims against Oasis Petroleum Inc. and OP LLC in connection with the derailment of the Train in Lac-Mégantic, Quebec are without merit and intends to vigorously defend against them.

Table of Contents

15. Condensed Consolidating Financial Information

The Notes (see Note 8) 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 parent company, Oasis Petroleum Inc. ("Issuer"), and its Guarantors on a combined basis, prepared on the equity basis of accounting. The Non-Guarantor Subsidiaries are immaterial and, therefore, not presented separately. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantors operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantors because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantors.

Condensed Consolidating Balance Sheet

(In thousands, except share data)

	June 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$1,603	$25,354	$—	$26,957
Accounts receivable – oil and gas revenues	—	216,764	—	216,764
Accounts receivable – joint interest partners	—	147,056	—	147,056
Accounts receivable – affiliates	781	13,416	(14,197)	—
Inventory	—	17,636	—	17,636
Prepaid expenses	—	8,907	—	8,907
Deferred income taxes	—	25,390	—	25,390
Advances to joint interest partners	—	97	—	97
Other current assets	—	421	—	421
Total current assets	2,384	455,041	(14,197)	443,228
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	5,141,582	—	5,141,582
Other property and equipment	—	231,129	—	231,129
Less: accumulated depreciation, depletion, amortization and impairment	—	(823,500)	—	(823,500)
Total property, plant and equipment, net	—	4,549,211	—	4,549,211
Investments in and advances to subsidiaries	3,675,495	—	(3,675,495)	—
Deferred income taxes	117,199	—	(117,199)	—
Deferred costs and other assets	31,726	12,814	—	44,540
Total assets	$3,826,804	$5,017,066	$(3,806,891)	$5,036,979
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable	$—	$32,402	$—	$32,402
Accounts payable – affiliates	13,416	781	(14,197)	—
Revenues and production taxes payable	—	217,414	—	217,414
Accrued liabilities	24	288,789	—	288,813

Accrued interest payable	49,340	104	—	49,444
Derivative instruments	—	62,415	—	62,415
Advances from joint interest partners	—	6,910	—	6,910
Other current liabilities	—	3,311	—	3,311
Total current liabilities	62,780	612,126	(14,197)	660,709
Long-term debt	2,200,000	100,000	—	2,300,000
Deferred income taxes	—	578,096	(117,199)	460,897
Asset retirement obligations	—	37,542	—	37,542
Derivative instruments	—	11,844	—	11,844
Other liabilities	—	1,963	—	1,963
Total liabilities	2,262,780	1,341,571	(131,396)	3,472,955
Stockholders’ equity				
Capital contributions from affiliates	—	2,893,387	(2,893,387)	—
Common stock, $0.01 par value: 300,000,000 shares authorized; 101,396,597 issued	999	—	—	999
Treasury stock, at cost: 244,729 shares	(8,677)	—	—	(8,677)
Additional paid-in capital	995,024	8,743	(8,743)	995,024
Retained earnings	576,678	773,365	(773,365)	576,678
Total stockholders’ equity	1,564,024	3,675,495	(3,675,495)	1,564,024
Total liabilities and stockholders’ equity	$3,826,804	$5,017,066	$(3,806,891)	$5,036,979

Table of Contents

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

	December 31, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$34,277	$57,624	$—	$91,901
Accounts receivable – oil and gas revenues	—	175,653	—	175,653
Accounts receivable – joint interest partners	—	139,459	—	139,459
Accounts receivable – affiliates	770	9,100	(9,870)	—
Inventory	—	20,652	—	20,652
Prepaid expenses	318	9,873	—	10,191
Deferred income taxes	—	6,335	—	6,335
Derivative instruments	—	2,264	—	2,264
Advances to joint interest partners	—	760	—	760
Other current assets	—	391	—	391
Total current assets	35,365	422,111	(9,870)	447,606
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	4,528,958	—	4,528,958
Other property and equipment	—	188,468	—	188,468
Less: accumulated depreciation, depletion, amortization and impairment	—	(637,676)	—	(637,676)
Total property, plant and equipment, net	—	4,079,750	—	4,079,750
Assets held for sale	—	137,066	—	137,066
Investments in and advances to subsidiaries	3,450,668	—	(3,450,668)	—
Derivative instruments	—	1,333	—	1,333
Deferred income taxes	85,288	—	(85,288)	—
Deferred costs and other assets	33,983	12,186	—	46,169
Total assets	$3,605,304	$4,652,446	$(3,545,826)	$4,711,924
LIABILITIES AND STOCKHOLDERS’ EQUITY				
Current liabilities				
Accounts payable	$—	$8,920	$—	$8,920
Accounts payable – affiliates	9,100	770	(9,870)	—
Revenues and production taxes payable	—	146,741	—	146,741
Accrued liabilities	33	241,797	—	241,830
Accrued interest payable	47,622	288	—	47,910
Derivative instruments	—	8,188	—	8,188
Advances from joint interest partners	—	12,829	—	12,829
Total current liabilities	56,755	419,533	(9,870)	466,418
Long-term debt	2,200,000	335,570	—	2,535,570
Deferred income taxes	—	408,435	(85,288)	323,147
Asset retirement obligations	—	35,918	—	35,918
Derivative instruments	—	139	—	139
Other liabilities	—	2,183	—	2,183
Total liabilities	2,256,755	1,201,778	(95,158)	3,363,375
Stockholders’ equity				
Capital contributions from affiliates	—	2,930,978	(2,930,978)	—

Common stock, $0.01 par value: 300,000,000 shares authorized; 100,866,589 issued	996	—	—	996
Treasury stock, at cost: 167,155 shares	(5,362)	—	—	(5,362)
Additional paid-in capital	985,023	8,743	(8,743)	985,023
Retained earnings	367,892	510,947	(510,947)	367,892
Total stockholders' equity	1,348,549	3,450,668	(3,450,668)	1,348,549
Total liabilities and stockholders' equity	$3,605,304	$4,652,446	$(3,545,826)	$4,711,924

Table of Contents

Condensed Consolidating Statement of Operations
(In thousands)

	Three Months Ended June 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$354,182	$—	$354,182
Well services and midstream revenues	—	18,196	—	18,196
Total revenues	—	372,378	—	372,378
Expenses				
Lease operating expenses	—	40,553	—	40,553
Well services and midstream operating expenses	—	8,769	—	8,769
Marketing, transportation and gathering expenses	—	7,114	—	7,114
Production taxes	—	34,493	—	34,493
Depreciation, depletion and amortization	—	97,276	—	97,276
Exploration expenses	—	475	—	475
Impairment of oil and gas properties	—	42	—	42
General and administrative expenses	5,805	14,946	—	20,751
Total expenses	5,805	203,668	—	209,473
Gain on sale of properties	—	3,640	—	3,640
Operating income (loss)	(5,805)	172,350	—	166,545
Other income (expense)				
Equity in earnings in subsidiaries	65,485	—	(65,485)	—
Net loss on derivative instruments	—	(65,570)	—	(65,570)
Interest expense, net of capitalized interest	(36,705)	(2,285)	—	(38,990)
Other income (expense)	—	135	—	135
Total other income (expense)	28,780	(67,720)	(65,485)	(104,425)
Income before income taxes	22,975	104,630	(65,485)	62,120
Income tax benefit (expense)	15,858	(39,145)	—	(23,287)
Net income	$38,833	$65,485	$(65,485)	$38,833

Condensed Consolidating Statement of Operations
(In thousands)

	Three Months Ended June 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$241,842	$—	$241,842
Well services and midstream revenues	—	12,740	—	12,740
Total revenues	—	254,582	—	254,582
Expenses				
Lease operating expenses	—	18,266	—	18,266
Well services and midstream operating expenses	—	6,644	—	6,644
Marketing, transportation and gathering expenses	—	10,779	—	10,779
Production taxes	—	21,397	—	21,397

Depreciation, depletion and amortization	—	66,790	—	66,790
Exploration expenses	—	392	—	392
Impairment of oil and gas properties	—	208	—	208
General and administrative expenses	3,524	13,132	—	16,656
Total expenses	3,524	137,608	—	141,132
Operating income (loss)	(3,524)	116,974	—	113,450
Other income (expense)				
Equity in earnings in subsidiaries	82,506	—	(82,506)	—
Net gain on derivative instruments	—	12,591	—	12,591
Interest expense, net of capitalized interest	(20,159)	(1,233)	—	(21,392)
Other income (expense)	(738)	1,032	—	294
Total other income (expense)	61,609	12,390	(82,506)	(8,507)
Income before income taxes	58,085	129,364	(82,506)	104,943
Income tax benefit (expense)	9,034	(46,858)	—	(37,824)
Net income	$67,119	$82,506	$(82,506)	$67,119

Condensed Consolidating Statement of Operations
(In thousands)

	Six Months Ended June 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$686,029	$—	$686,029
Well services and midstream revenues	—	35,868	—	35,868
Total revenues	—	721,897	—	721,897
Expenses				
Lease operating expenses	—	80,542	—	80,542
Well services and midstream operating expenses	—	19,689	—	19,689
Marketing, transportation and gathering expenses	—	12,300	—	12,300
Production taxes	—	66,296	—	66,296
Depreciation, depletion and amortization	—	188,548	—	188,548
Exploration expenses	—	855	—	855
Impairment of oil and gas properties	—	804	—	804
General and administrative expenses	11,417	32,854	—	44,271
Total expenses	11,417	401,888	—	413,305
Gain on sale of properties	—	187,033	—	187,033
Operating income (loss)	(11,417)	507,042	—	495,625
Other income (expense)				
Equity in earnings in subsidiaries	262,418	—	(262,418)	—
Net loss on derivative instruments	—	(83,173)	—	(83,173)
Interest expense, net of capitalized interest	(74,129)	(5,019)	—	(79,148)
Other income (expense)	3	285	—	288
Total other income (expense)	188,292	(87,907)	(262,418)	(162,033)
Income before income taxes	176,875	419,135	(262,418)	333,592
Income tax benefit (expense)	31,911	(156,717)	—	(124,806)
Net income	$208,786	$262,418	$(262,418)	$208,786

Condensed Consolidating Statement of Operations
(In thousands)

	Six Months Ended June 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$483,493	$—	$483,493
Well services and midstream revenues	—	19,393	—	19,393
Total revenues	—	502,886	—	502,886
Expenses				
Lease operating expenses	—	37,755	—	37,755
Well services and midstream operating expenses	—	9,558	—	9,558
Marketing, transportation and gathering expenses	—	14,168	—	14,168
Production taxes	—	43,486	—	43,486
Depreciation, depletion and amortization	—	133,051	—	133,051
Exploration expenses	—	2,249	—	2,249
Impairment of oil and gas properties	—	706	—	706
General and administrative expenses	6,400	24,110	—	30,510
Total expenses	6,400	265,083	—	271,483
Operating income (loss)	(6,400)	237,803	—	231,403
Other income (expense)				
Equity in earnings in subsidiaries	148,751	—	(148,751)	—
Net loss on derivative instruments	—	(2,021)	—	(2,021)
Interest expense, net of capitalized interest	(40,678)	(1,897)	—	(42,575)
Other income (expense)	(363)	1,437	—	1,074
Total other income (expense)	107,710	(2,481)	(148,751)	(43,522)
Income before income taxes	101,310	235,322	(148,751)	187,881
Income tax benefit (expense)	17,660	(86,571)	—	(68,911)
Net income	$118,970	$148,751	$(148,751)	$118,970

Table of Contents

Condensed Consolidating Statement of Cash Flows
(In thousands)

	Six Months Ended June 30, 2014			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$208,786	$262,418	$(262,418)	$208,786
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(262,418)	—	262,418	—
Depreciation, depletion and amortization	—	188,548	—	188,548
Gain on sale of properties	—	(187,033)		(187,033)
Impairment of oil and gas properties	—	804	—	804
Deferred income taxes	(31,911)	150,606	—	118,695
Derivative instruments	—	83,173	—	83,173
Stock-based compensation expenses	9,522	156	—	9,678
Debt discount amortization and other	2,255	965	—	3,220
Working capital and other changes:				
Change in accounts receivable	(11)	(41,448)	4,327	(37,132)
Change in inventory	—	3,016	—	3,016
Change in prepaid expenses	318	966	—	1,284
Change in other current assets	—	(30)	—	(30)
Change in other assets	—	(1,477)	—	(1,477)
Change in accounts payable and accrued liabilities	6,025	89,845	(4,327)	91,543
Change in other current liabilities	—	3,311	—	3,311
Change in other liabilities	—	(132)	—	(132)
Net cash provided by (used in) operating activities	(67,434)	553,688	—	486,254
Cash flows from investing activities:				
Capital expenditures	—	(606,924)	—	(606,924)
Acquisition of oil and gas properties	—	(8,116)	—	(8,116)
Proceeds from sale of properties	—	324,888	—	324,888
Costs related to sale of properties	—	(2,337)		(2,337)
Derivative settlements	—	(13,644)	—	(13,644)
Advances from joint interest partners	—	(5,919)	—	(5,919)
Net cash used in investing activities	—	(312,052)	—	(312,052)
Cash flows from financing activities:				
Proceeds from revolving credit facility	—	100,000	—	100,000
Principal payments on revolving credit facility	—	(335,570)	—	(335,570)
Purchases of treasury stock	(3,315)	—	—	(3,315)
Debt issuance costs	—	(85)	—	(85)
Investment in / capital contributions from affiliates	38,251	(38,251)	—	—
Other	(176)	—	—	(176)
Net cash provided by (used in) financing activities	34,760	(273,906)	—	(239,146)
Decrease in cash and cash equivalents	(32,674)	(32,270)	—	(64,944)
Cash and cash equivalents at beginning of period	34,277	57,624	—	91,901
Cash and cash equivalents at end of period	$1,603	$25,354	$—	$26,957

Condensed Consolidating Statement of Cash Flows
(In thousands)

	Six Months Ended June 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$118,970	$148,751	$(148,751)	$118,970
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(148,751)	—	148,751	—
Depreciation, depletion and amortization	—	133,051	—	133,051
Impairment of oil and gas properties	—	706	—	706
Deferred income taxes	(17,660)	85,634	—	67,974
Derivative instruments	—	2,021	—	2,021
Stock-based compensation expenses	5,263	108	—	5,371
Debt discount amortization and other	2,189	(436)	—	1,753
Working capital and other changes:				
Change in accounts receivable	(461)	(13,972)	665	(13,768)
Change in inventory	—	(4,200)	—	(4,200)
Change in prepaid expenses	313	(4,715)	—	(4,402)
Change in other current assets	232	98	—	330
Change in accounts payable and accrued liabilities	(388)	49,754	(665)	48,701
Change in other current liabilities	—	688	—	688
Change in other liabilities	—	612	—	612
Net cash provided by (used in) operating activities	(40,293)	398,100	—	357,807
Cash flows from investing activities:				
Capital expenditures	—	(428,630)	—	(428,630)
Derivative settlements	—	2,932	—	2,932
Redemptions of short-term investments	25,000	—	—	25,000
Advances from joint interest partners	—	(5,593)	—	(5,593)
Net cash provided by (used in) investing activities	25,000	(431,291)	—	(406,291)
Cash flows from financing activities:				
Purchases of treasury stock	(364)	—	—	(364)
Debt issuance costs	—	(2,998)	—	(2,998)
Investment in / capital contributions from affiliates	(34,370)	34,370	—	—
Net cash provided by (used in) financing activities	(34,734)	31,372	—	(3,362)
Decrease in cash and cash equivalents	(50,027)	(1,819)	—	(51,846)
Cash and cash equivalents at beginning of period	133,797	79,650	—	213,447
Cash and cash equivalents at end of period	$83,770	$77,831	$—	$161,601

16. 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.

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, 2013 ("2013 Annual Report"), as well as the unaudited condensed consolidated financial statements and notes thereto included in this Quarterly Report on Form 10-Q.

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report on Form 10-Q, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed under Item 1A. "Risk Factors" in our 2013 Annual Report could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- timing and amount of future production of oil and natural gas;
- drilling and completion of wells;
- estimated inventory of wells remaining to be drilled and completed;
- costs of exploiting and developing our properties and conducting other operations;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating well services and midstream companies;
- infrastructure for salt water disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- property acquisitions;
- integration and benefits of property acquisitions, including our recent acquisitions of oil and gas properties in our West Williston and East Nesson project areas, or the effects of such acquisitions on our cash position and levels of indebtedness;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- our financial strategy, budget, projections, execution of business plan and operating results;
- cash flows and liquidity;
- oil and natural gas realized prices;
- general economic conditions;
- operating environment, including inclement weather conditions;
- effectiveness of risk management activities;
- competition in the oil and natural gas industry;
- counterparty credit risk;
- environmental liabilities;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- technology;

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

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

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

- commodity prices for oil and natural gas;
- transportation capacity;
- availability and cost of services; and
- availability of qualified personnel.

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

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk, and enter into physical delivery contracts to manage our price differentials. In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, we sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of June 30, 2014, we were flowing approximately 75% of our gross operated oil production through these gathering systems.

Table of Contents

Changes in commodity prices may also significantly affect the economic viability of drilling projects and economic recovery of oil and gas reserves. As a result of higher commodity prices and continued successes in the application of completion technologies in the Bakken and Three Forks formations, there were approximately 200 active drilling rigs in the Williston Basin at June 30, 2014. Although additional Williston Basin transportation takeaway capacity was added in recent years, production also increased due to the elevated drilling activity. The increased production coupled with delays in rail car arrivals and commissioning of rail loading facilities caused price differentials at times to be at the high-end of the historical average range of approximately 10% to 15% of the price quoted for NYMEX West Texas Intermediate ("WTI") crude oil in the first half of 2012. In the third quarter of 2012, our average price differentials relative to WTI began to narrow, primarily due to transportation capacity additions, including expanded rail infrastructure and pipeline expansions, outpacing production growth. In the fourth quarter of 2012 and into the first quarter of 2013, average price differentials continued to narrow, primarily due to our ability to access premium coastal markets by rail. As the premium received in coastal markets contracted during the second and third quarters of 2013, our average price differentials relative to WTI increased. In the fourth quarter of 2013 and into the first quarter of 2014, our average price differentials relative to WTI continued to increase due to the pipeline market weakening as a result of refinery down time and increased United States and Canadian production. More recently, the pipeline and rail markets have been balanced, and our price differentials to WTI have returned to approximately 8% to 9%. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations.

Second Quarter 2014 Highlights:

- We completed and placed on production 41 gross (30.8 net) operated wells in the Williston Basin during the three months ended June 30, 2014;
- We had approximately 16 rigs running during the second quarter of 2014, and as of June 30, 2014, we had an inventory of gross operated wells waiting on completion of 35 wells in our West Williston project area and 32 wells in our East Nesson project area;
- Average daily production was 43,668 Boe per day during the three months ended June 30, 2014;
- E&P capital expenditures were $326.9 million, consisting primarily of $291.0 million in drilling and completion expenditures during the three months ended June 30, 2014;
- At June 30, 2014, we had $27.0 million of cash and cash equivalents and had total liquidity of $1,421.8 million, including our $1,500.0 revolving credit facility; and
- Adjusted EBITDA, a non-GAAP financial measure, was $254.7 million for the three months ended June 30, 2014. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities, see "Non-GAAP Financial Measures" below.

Results of Operations

Revenues

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

Table of Contents

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
Operating results (in thousands):						
Revenues						
Oil	$334,559	$232,625	$101,934	$643,790	$464,300	$179,490
Natural gas	19,623	9,217	10,406	42,239	19,193	23,046
Well services and midstream	18,196	12,740	5,456	35,868	19,393	16,475
Total revenues	372,378	254,582	117,796	721,897	502,886	219,011
Production data:						
Oil (MBbls)	3,541	2,489	1,052	6,990	4,971	2,019
Natural gas (MMcf)	2,596	1,540	1,056	5,045	2,929	2,116
Oil equivalents (MBoe)	3,974	2,746	1,228	7,831	5,459	2,372
Average daily production (Boe/d)	43,668	30,171	13,497	43,264	30,162	13,102
Average sales prices:						
Oil, without derivative settlements (per Bbl)(1)	$94.48	$91.15	$3.33	$92.10	$92.24	$(0.14)
Oil, with derivative settlements (per Bbl)(1)(2)	91.26	91.65	(0.39)	90.15	92.83	(2.68)
Natural gas (per Mcf)(3)	7.56	5.98	1.58	8.37	6.55	1.82

(1) For the three and six months ended June 30, 2013, average sales prices for oil are calculated using total oil revenues, excluding bulk oil sales of $5.8 million, divided by oil production.

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

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

Three months ended June 30, 2014 as compared to three months ended June 30, 2013

Our total revenues increased $117.8 million, or 46%, to $372.4 million during the three months ended June 30, 2014 as compared to the three months ended June 30, 2013.

Oil and gas revenues. 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 13,497 Boe per day, or 45%, to 43,668 Boe per day during the three months ended June 30, 2014 as compared to the three months ended June 30, 2013. The increase in average daily production sold was primarily a result of our well completions during the twelve months ended June 30, 2014 and our four distinct acquisitions during 2013 of approximately 161,000 net acres in and around our West Williston and East Nesson project areas (the “2013 Acquisitions”), offset by the decline in production in wells that were producing as of June 30, 2013. Average daily production in our West Williston and East Nesson project areas increased by 12,124 Boe per day and 3,975 Boe per day, respectively, during the second quarter of 2014 as compared to the second quarter of 2013. Average daily production in our Sanish project area decreased 2,602 Boe per day during the second quarter of 2014 as compared to the second quarter of 2013 as a result of the the sale of certain non-operated properties in our Sanish project area and other non-operated leases adjacent to our Sanish position (the “Sanish Divestiture”) during the first quarter of 2014. Average oil sales prices, without derivative settlements, increased by $3.33/Bbl to an average of $94.48/Bbl, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, increased by $1.58/Mcf to an average of $7.56/Mcf for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013. The higher production amounts sold increased revenues by $107.4 million and higher oil and natural gas sales prices increased revenues by $10.7 million during the three months ended June 30, 2014 compared to the three months ended June 30, 2013. In addition, there was a $5.8 million decrease in bulk oil sales related to marketing activities included in oil revenues during the three months ended June 30, 2014 as compared to the three months ended June 30, 2013.

Well services and midstream revenues. Well services revenues increased $3.4 million for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013 due to an increase in well completion activity, related product sales and tool rentals. Midstream revenues were $3.3 million, a $2.0 million increase quarter over quarter, primarily due to increased water volumes flowing through our salt water disposal systems and fresh water sales. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA’s operated wells only, as work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation.

Six months ended June 30, 2014 as compared to six months ended June 30, 2013

Table of Contents

Our total revenues increased $219.0 million, or 44%, to $721.9 million during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013.

Oil and gas revenues. 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 13,102 Boe per day, or 43%, to 43,264 Boe per day during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. The increase in average daily production sold was primarily a result of our well completions during the twelve months ended June 30, 2014 coupled with the 2013 Acquisitions, offset by the decline in production in wells that were producing as of June 30, 2013. Average daily production in our West Williston and East Nesson project areas increased by 10,674 Boe per day and 4,283 Boe per day, respectively, during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. Average daily production in our Sanish project area decreased 1,855 Boe per day during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013 as a result of the Sanish Divestiture during the first quarter of 2014. Average oil sales prices, without derivative settlements, decreased by $0.14/Bbl to an average of $92.10/Bbl, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, increased by $1.82/Mcf to an average of $8.37/Mcf for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. The higher production amounts sold increased revenues by $203.6 million, while higher natural gas sales prices, offset by a slight decrease in oil sales prices, increased revenues by $4.6 million during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. In addition, there was a $5.8 million decrease in bulk oil sales related to marketing activities included in oil revenues during the six months ended June 30, 2014 as compared to the six months ended June 30, 2013.

Well services and midstream revenues. Well services revenues increased $13.5 million for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013 due to an increase in well completion activity, related product sales and tool rentals. Midstream revenues were $5.2 million, a $2.9 million increase period over period, primarily due to increased water volumes flowing through our salt water disposal systems and fresh water sales. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA's operated wells only, as work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation.

Table of Contents

Expenses and gain on sale of properties

The following table summarizes our operating and other expenses and our gain on sale of properties for the periods presented:

	Three Months Ended June 30,			Six Months Ended June 30,		
	2014	2013	Change	2014	2013	Change
	(In thousands, except per Boe of production)					
Expenses:						
Lease operating expenses	$40,553	$18,266	$22,287	$80,542	$37,755	$42,787
Well services and midstream operating expenses	8,769	6,644	2,125	19,689	9,558	10,131
Marketing, transportation and gathering expenses	7,114	10,779	(3,665)	12,300	14,168	(1,868)
Production taxes	34,493	21,397	13,096	66,296	43,486	22,810
Depreciation, depletion and amortization	97,276	66,790	30,486	188,548	133,051	55,497
Exploration expenses	475	392	83	855	2,249	(1,394)
Impairment of oil and gas properties	42	208	(166)	804	706	98
General and administrative expenses	20,751	16,656	4,095	44,271	30,510	13,761
Total expenses	209,473	141,132	68,341	413,305	271,483	141,822
Gain on sale of properties	3,640	—	3,640	187,033	—	187,033
Operating income	166,545	113,450	53,095	495,625	231,403	264,222
Other income (expense):						
Net gain (loss) on derivative instruments	(65,570)	12,591	(78,161)	(83,173)	(2,021)	(81,152)
Interest expense, net of capitalized interest	(38,990)	(21,392)	(17,598)	(79,148)	(42,575)	(36,573)
Other income (expense)	135	294	(159)	288	1,074	(786)
Total other income (expense)	(104,425)	(8,507)	(95,918)	(162,033)	(43,522)	(118,511)
Income before income taxes	62,120	104,943	(42,823)	333,592	187,881	145,711
Income tax expense	23,287	37,824	(14,537)	124,806	68,911	55,895
Net income	$38,833	$67,119	$(28,286)	$208,786	$118,970	$89,816
Cost and expense (per Boe of production):						
Lease operating expenses	$10.21	$6.65	$3.56	$10.29	$6.92	$3.37
Marketing, transportation and gathering expenses	1.79	3.93	(2.14)	1.57	2.60	(1.03)
Production taxes	8.68	7.79	0.89	8.47	7.97	0.50
Depreciation, depletion and amortization	24.48	24.33	0.15	24.08	24.37	(0.29)
General and administrative expenses	5.22	6.07	(0.85)	5.65	5.58	0.07

Three months ended June 30, 2014 as compared to three months ended June 30, 2013

Lease operating expenses. Lease operating expenses increased $22.3 million to $40.6 million for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our well completions and the 2013 Acquisitions, as well as increased workover costs, which include costs to protect producing wells from wells that are being completed. Lease operating expenses increased from $6.65 per Boe for the three months ended June 30, 2013 to $10.21 per Boe for the three months ended June 30, 2014.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and midstream operating expenses incurred by OMS. The $2.1 million increase for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013 was attributable to a $0.8 million increase from OWS' well completion activity and related product sales, and a $1.3 million increase related to midstream services operating expenses.

Marketing, transportation and gathering expenses. The $3.7 million decrease for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013 was primarily attributable to a $5.8 million decrease in bulk oil purchases made by OPM, offset by increased oil transportation costs associated with having additional wells connected to third-party infrastructure. In addition, there was a $0.1 million increase due to the change in the non-cash valuation adjustments on our oil pipeline imbalances. Excluding bulk oil purchases and non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis would have been $1.76 and $1.82 for the three months ended June 30, 2014 and 2013,

Table of Contents

respectively. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the three months ended June 30, 2014 and 2013 were 9.7% and 9.1%, respectively, as a percentage of oil and natural gas sales. The second quarter 2014 production tax rate was higher than the second quarter 2013 production tax rate primarily due to the increased weighting of wells in North Dakota compared to Montana, which has lower production tax rates. For the three months ended June 30, 2014 and 2013, the percentage of our total production located in North Dakota was 86% and 80%, respectively, with an average production tax rate of approximately 10.5%.

Depreciation, depletion and amortization (“DD&A”). DD&A expense increased $30.5 million to $97.3 million for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013. This increase in DD&A expense for the three months ended June 30, 2014 was a result of the production increases from our wells completed during the twelve months ended June 30, 2014 and the 2013 Acquisitions. The DD&A rate for the three months ended June 30, 2014 was $24.48 per Boe compared to $24.33 per Boe for the three months ended June 30, 2013.

Impairment of oil and gas properties. During the three months ended June 30, 2014 and 2013, we recorded non-cash impairment charges of $42,000 and $0.2 million, respectively for expiring leases. No impairment charges of proved oil and gas properties were recorded for the three months ended June 30, 2014 or 2013.

General and administrative (“G&A”) expenses. Our G&A expenses increased $4.1 million for the three months ended June 30, 2014 from $16.7 million for the three months ended June 30, 2013. Of this increase, approximately $3.3 million related to increased employee compensation expense due to our organizational growth and $2.1 million was due to increased amortization of our restricted stock awards and performance share units quarter over quarter. As of June 30, 2014, we had 522 full-time employees compared to 322 full-time employees as of June 30, 2013. There were offsetting decreases to G&A related to OWS and OMS of $1.4 million and $0.4 million, respectively, quarter over quarter.

Gain on sale of properties. During the three months ended June 30, 2014, we recognized a gain on sale of properties of $3.6 million for post close adjustments related to the Sanish Divestiture in the first quarter of 2014. No gain or loss on sale of properties was recorded for the three months ended June 30, 2013.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net loss of $11.4 million for the three months ended June 30, 2014 and a cash settlement net gain of $1.2 million for the three months ended June 30, 2013. In addition, as a result of forward oil price changes, we recognized a $54.2 million non-cash mark-to-market net derivative loss during the three months ended June 30, 2014 and an $11.3 million non-cash mark-to-market net derivative gain during the three months ended June 30, 2013.

Interest expense. Interest expense increased $17.6 million to $39.0 million for the three months ended June 30, 2014 as compared to the three months ended June 30, 2013. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in September 2013 at an interest rate of 6.875% coupled with interest expense incurred on borrowings under our revolving credit facility during the three months ended June 30, 2014. For the three months ended June 30, 2014, the weighted average debt outstanding under our revolving credit facility was $121.5 million and the weighted average interest rate incurred on the outstanding borrowings was 1.7%. There were no borrowings under our revolving credit facility during the three months ended June 30, 2013. Interest capitalized during the three months ended June 30, 2014 and 2013 was $2.3 million and $1.1 million, respectively.

Income taxes. Income tax expense for the three months ended June 30, 2014 and 2013 was recorded at 37.5% and 36.0% 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.

Six months ended June 30, 2014 as compared to six months ended June 30, 2013

Lease operating expenses. Lease operating expenses increased $42.8 million to $80.5 million for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our well completions and the 2013 Acquisitions, as well as increased workover costs, which relate to restoring wells that were down due to winter weather conditions and costs to protect producing wells from wells that are being completed. Lease operating expenses increased from $6.92 per Boe for the six months ended June 30, 2013 to $10.29 per Boe for the six months ended June 30, 2014.

Table of Contents

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and midstream operating expenses incurred by OMS. The $10.1 million increase for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013 was attributable to an $8.4 million increase from OWS' well completion activity and related product sales, and a $1.7 million increase related to midstream services operating expenses.

Marketing, transportation and gathering expenses. The $1.9 million decrease for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013 was primarily attributable to a $5.8 million decrease in bulk oil purchases made by OPM, offset by increased oil transportation costs associated with having additional wells connected to third-party infrastructure. In addition, there was a $0.7 million decrease due to the change in the non-cash valuation adjustments on our oil pipeline imbalances. Excluding bulk oil purchases and non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis would have been $1.65 and $1.52 for the six months ended June 30, 2014 and 2013, respectively. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the six months ended June 30, 2014 and 2013 were 9.7% and 9.1%, respectively, as a percentage of oil and natural gas sales. The 2014 production tax rate was higher than the 2013 production tax rate primarily due to the increased weighting of wells in North Dakota compared to Montana, which has lower production tax rates. For the six months ended June 30, 2014 and 2013, the percentage of our total production located in North Dakota was 86% and 80%, respectively, with an average production tax rate of approximately 10.5%.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $55.5 million to $188.5 million for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. This increase in DD&A expense for the six months ended June 30, 2014 was a result of the production increases from our wells completed during the twelve months ended June 30, 2014 and the 2013 Acquisitions. The DD&A rate for the six months ended June 30, 2014 was $24.08 per Boe as compared to $24.37 per Boe for the six months ended June 30, 2013. In the first two months of 2014, we had production from the wells sold in the Sanish Divestiture, but these wells were not depreciated because the assets were held for sale, which lowered DD&A by $0.38 per Boe for the six months ended June 30, 2014.

Impairment of oil and gas properties. During the six months ended June 30, 2014 and 2013, we recorded non-cash impairment charges of $0.8 million and $0.7 million, respectively, for expiring leases. No impairment charges of proved oil and gas properties were recorded for the six months ended June 30, 2014 or 2013.

General and administrative ("G&A") expenses. Our G&A expenses increased $13.8 million for the six months ended June 30, 2014 from $30.5 million for the six months ended June 30, 2013. Of this increase, approximately $10.1 million related to increased employee compensation expense due to our organizational growth and $4.3 million was due to increased amortization of our restricted stock awards and performance share units. As of June 30, 2014, we had 522 full-time employees compared to 322 full-time employees as of June 30, 2013. There were offsetting decreases to G&A related to OWS and OMS of $1.2 million and $1.0 million, respectively, for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013.

Gain on sale of properties. We recognized a gain on sale of properties of $187.0 million for the Sanish Divestiture in the six months ended June 30, 2014. No gain or loss on sale of properties was recorded in the six months ended June 30, 2013.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net loss of $13.6 million for the six months ended June 30, 2014 and a cash settlement net gain of $2.9 million for the six months ended June 30, 2013. In addition, as a result of forward oil price changes, we recognized a $69.5 million and a $5.0 million non-cash mark-to-market net derivative loss during the six months ended June 30, 2014 and 2013, respectively.

Interest expense. Interest expense increased $36.6 million to $79.1 million for the six months ended June 30, 2014 as compared to the six months ended June 30, 2013. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in September 2013 at an interest rate of 6.875% coupled with interest expense incurred on borrowings under our revolving credit facility during the six months ended June 30, 2014. For the six months ended June 30, 2014, the weighted average debt outstanding under our revolving credit facility was $188.4 million and the weighted average interest rate incurred on the outstanding borrowings was 1.7%. There were no borrowings under our revolving credit facility during the six months ended June 30, 2013. Interest capitalized during the six months ended June 30, 2014 and 2013 was $3.8 million and $1.9 million, respectively.

Table of Contents

Income taxes. Income tax expense for the six months ended June 30, 2014 and 2013 was recorded at 37.4% and 36.7% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report are proceeds from our senior unsecured notes, borrowings and availability under our revolving credit facility, proceeds from public equity offerings and cash flows from operations. Our primary use of capital has been for the development and acquisition of oil and natural gas properties. We continually monitor potential capital sources, including 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 six months ended June 30, 2014 and 2013 are presented below:

	Six Months Ended June 30,	
	2014	2013
	(In thousands)	
Net cash provided by operating activities	$486,254	$357,807
Net cash used in investing activities	(312,052)	(406,291)
Net cash used in financing activities	(239,146)	(3,362)
Decrease in cash and cash equivalents	$(64,944)	$(51,846)

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

Cash flows provided by operating activities

Net cash provided by operating activities was $486.3 million and $357.8 million for the six months ended June 30, 2014 and 2013, respectively. The increase in cash flows provided by operating activities for the period ended June 30, 2014 as compared to 2013 was primarily the result of our 43% increase in oil and natural gas production, coupled with increases in well completion activity, related product sales and salt water disposal for non-affiliated working interest owners in OPNA’s operated wells.

Working capital. Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and acquisitions, and the impact of our outstanding derivative instruments. We had a working capital deficit of $217.5 million at June 30, 2014. We believe we have adequate liquidity to meet our working capital requirements. As of June 30, 2014, we had $1,421.8 million of liquidity available, including $27.0 million in cash and cash equivalents and $1,394.8 million available under our revolving credit facility. At June 30, 2013, we had a working capital surplus of $55.3 million.

Cash flows used in investing activities

Net cash used in investing activities was $312.1 million and $406.3 million during the six months ended June 30, 2014 and 2013, respectively. Net cash used in investing activities during the six months ended June 30, 2014 was primarily attributable to $606.9 million in capital expenditures primarily for drilling and development costs, partially offset by proceeds of $324.9 million related to the Sanish Divestiture. Net cash used in investing activities during the six months ended June 30, 2013 was primarily attributable to $428.6 million in capital expenditures primarily for drilling and development costs, partially offset by $25.0 million for the redemption of short-term investments.

Table of Contents

Our capital expenditures are summarized in the following table:

	Six Months Ended June 30, 2014 (In thousands)
Project Area:	
West Williston	$412,814
East Nesson	211,213
Total E&P capital expenditures(1)	624,027
OWS	25,313
Non-E&P capital expenditures(2)	9,993
Total capital expenditures(3)	$659,333

(1) Total E&P capital expenditures include $12.5 million for OMS, primarily related to pipelines and salt water disposal wells.
(2) Non-E&P capital expenditures include such items as administrative capital and capitalized interest.
(3) 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 changes in accrued liabilities from the previous reporting period for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

Our total 2014 capital expenditure budget is $1,425 million, which consists of:

- $1,250 million of drilling and completion (including production-related equipment) capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS);
- $60 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems;
- $25 million for maintaining and expanding our leasehold position;
- $19 million for field facilities and other miscellaneous E&P capital expenditures;
- $13 million for collection of subsurface reservoir data;
- $35 million for OWS, including district tools; and
- $23 million for other non-E&P capital, including items such as administrative capital and capitalized interest.

While we have budgeted $1,425 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. Additionally, if we acquire additional acreage, as was the case in 2013, our capital expenditures may be higher than budgeted. We believe that cash on hand, cash flows from operating activities and availability under our revolving credit facility should be sufficient to fund our 2014 capital expenditure budget. However, because the operated wells funded by our 2014 drilling plan represent only a small percentage of our gross potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control. We actively review acquisition opportunities on an ongoing basis. Our ability to make significant acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be

able to obtain on terms acceptable to us or at all.
Cash flows used in financing activities
Net cash used in financing activities was $239.1 million and $3.4 million for the six months ended June 30, 2014 and 2013, respectively. For the six months ended June 30, 2014, cash used in financing activities was primarily due to principal payments on our revolving credit facility partially offset by proceeds from borrowings under our revolving credit facility. For the six months ended June 30, 2013, cash used in financing activities was primarily attributable to deferred financing costs related to a second amended and restated credit agreement (the “Second Amended Credit Facility”), which included the semi-annual redetermination of our borrowing base under our revolving credit facility, entered into on April 5, 2013. For both the six

months ended June 30, 2014 and 2013, cash used in financing activities was also attributable to 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 September 24, 2013, we issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”). Interest is payable on the 2022 Notes semi-annually in arrears on each March 15 and September 15, commencing March 15, 2014. The 2022 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2022 Notes resulted in net proceeds to us of approximately $983.6 million, which we used to fund a portion of the 2013 Acquisitions.

At any time prior to September 15, 2016, we may redeem up to 35% of the 2022 Notes at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding after such redemption. Prior to September 15, 2017, we may redeem some or all of the 2022 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after September 15, 2017, we may redeem some or all of the 2022 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.438% for the twelve-month period beginning on September 15, 2017, 101.719% for the twelve-month period beginning on September 15, 2018 and 100.00% beginning on September 15, 2019, plus accrued and unpaid interest to the redemption date.

On June 30, 2014, we filed a registration statement on Form S-4 with the SEC to allow the holders of the 2022 Notes to exchange the 2022 Notes for the same principal amount of a new issue of notes with substantially identical terms, except the new notes will be freely transferable under the Securities Act. The registration statement was declared effective on July 16, 2014. We will use commercially reasonable efforts to cause the exchange to be completed within 360 days after the 2022 Notes issuance date. Under certain circumstances, in lieu of a registered exchange offer, we must use commercially reasonable efforts to file a shelf registration statement for the resale of the 2022 Notes. If we fail to satisfy these obligations on a timely basis, the annual interest borne by the 2022 Notes will be increased by 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective. We estimate the value of this contingent interest is immaterial at June 30, 2014 and December 31, 2013.

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

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

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

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

Table of Contents

the twelve-month period beginning on November 1, 2018 and 100.00% beginning on November 1, 2019, plus accrued and unpaid interest to the redemption date.

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

Prior to February 1, 2015, we may redeem some or all of the 2019 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, we may redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning on February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

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

Senior secured revolving line of credit. On April 5, 2013, we entered into the Second Amended Credit Facility, which has a maturity date of April 5, 2018. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On March 27, 2014, the lenders under our Second Amended Credit Facility (the "Lenders") completed their regular semi-annual redetermination of the borrowing base, resulting in an increase to the borrowing base from $1,500.0 million to $1,750.0 million. However, we elected to limit the Lenders' aggregate commitment to $1,500.0 million. The overall senior secured line of credit under our Second Amended Credit Facility is $2,500.0 million as of June 30, 2014.

Borrowings under our Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. At our election, interest is generally determined by reference to (i) the London interbank offered rate ("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 June 30, 2014, we had $100.0 million of borrowings and $5.2 million outstanding letters of credit under our Second Amended Credit Facility, resulting in an unused borrowing base capacity of $1,394.8 million.

The Second Amended Credit Facility also contains certain financial covenants and customary events of default. If an event of default occurs and is continuing, the Lenders may declare all amounts outstanding under our Second Amended Credit Facility to be immediately due and payable. As of June 30, 2014, we were in compliance with the financial covenants of our Second Amended Credit Facility.

Non-GAAP Financial Measures

Adjusted EBITDA and Adjusted Net Income are supplemental non-GAAP financial measures that are used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. These non-GAAP measures should not be considered in isolation or as a substitute for net income, operating income, net cash provided by operating activities or any other measures prepared under accounting principles generally accepted in the United States of America ("GAAP"). Because Adjusted EBITDA and Adjusted Net Income exclude some but not all items that affect net income and may vary among companies, the amounts presented may not be comparable to similar metrics of other companies.

Adjusted EBITDA

We define Adjusted EBITDA as earnings before interest expense, income taxes, depreciation, depletion, amortization, exploration expenses and other similar non-cash or non-recurring charges. Adjusted EBITDA is not a measure of net income or cash flows as determined by GAAP. Management believes that the presentation of Adjusted EBITDA provides useful additional

Table of Contents

information to investors and analysts for assessing our results of operations and our ability to incur and service debt and to fund capital expenditures.

The following table presents reconciliations of the non-GAAP financial measure of Adjusted EBITDA to the GAAP financial measures of net income and net cash provided by operating activities for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands)			
Adjusted EBITDA reconciliation to net income:				
Net income	$38,833	$67,119	$208,786	$118,970
Gain on sale of properties	(3,640)	—	(187,033)	—
Non-cash change in fair value of derivative instruments	54,165	(11,345)	69,529	4,953
Interest expense	38,990	21,392	79,148	42,575
Depreciation, depletion and amortization	97,276	66,790	188,548	133,051
Impairment of oil and gas properties	42	208	804	706
Exploration expenses	475	392	855	2,249
Stock-based compensation expenses	5,173	3,082	9,678	5,371
Income tax expense	23,287	37,824	124,806	68,911
Other non-cash adjustments	118	25	(628)	74
Adjusted EBITDA	$254,719	$185,487	$494,493	$376,860
Adjusted EBITDA reconciliation to net cash provided by operating activities:				
Net cash provided by operating activities	$277,987	$187,260	$486,254	$357,807
Derivative settlements	(11,405)	1,246	(13,644)	2,932
Interest expense	38,990	21,392	79,148	42,575
Exploration expenses	475	392	855	2,249
Debt discount amortization and other	(1,733)	(1,007)	(3,220)	(1,753)
Current tax expense	3,345	837	6,111	937
Changes in working capital	(53,058)	(24,658)	(60,383)	(27,961)
Other non-cash adjustments	118	25	(628)	74
Adjusted EBITDA	$254,719	$185,487	$494,493	$376,860

Adjusted Net Income

We define Adjusted Net Income as net income after adjusting first for (1) the impact of certain non-cash and non-recurring items, including non-cash changes in the fair value of derivative instruments, impairment of oil and gas properties and other similar non-cash and non-recurring charges, and then (2) the non-cash and non-recurring items' impact on taxes based on our effective tax rate in the same period. Adjusted Net Income is not a measure of net income as determined by GAAP. We define Adjusted Diluted Earnings Per Share as Adjusted Net Income divided by diluted weighted average shares outstanding. Management believes that the presentation of Adjusted Net Income and Adjusted Diluted Earnings Per Share provides useful additional information to investors and analysts for evaluating our operational trends and performance.

Table of Contents

The following table provides reconciliations of the GAAP financial measure of net income to the non-GAAP financial measure of Adjusted Net Income and the GAAP financial measure of diluted earnings per share to the non-GAAP financial measure of Adjusted Diluted Earnings Per Share for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(In thousands, except per share data)			
Net income	$38,833	$67,119	$208,786	$118,970
Non-cash change in fair value of derivative instruments	54,165	(11,345)	69,529	4,953
Gain on sale of properties	(3,640)	—	(187,033)	—
Impairment of oil and gas properties	42	208	804	706
Other non-cash adjustments	118	25	(628)	74
Tax impact(1)	(19,000)	4,045	43,896	(2,145)
Adjusted Net Income	$70,518	$60,052	$135,354	$122,558
Diluted earnings per share	$0.39	$0.72	$2.08	$1.28
Non-cash change in fair value of derivative instruments	0.54	(0.12)	0.69	0.05
Gain on sale of properties	(0.04)	—	(1.86)	—
Impairment of oil and gas properties	—	—	0.01	0.01
Other non-cash adjustments	—	—	(0.01)	—
Tax impact(1)	(0.19)	0.05	0.44	(0.02)
Adjusted Diluted Earnings Per Share	$0.70	$0.65	$1.35	$1.32
Diluted weighted average shares outstanding	100,260	92,702	100,328	92,812
Effective tax rate	37.5%	36.0%	37.4%	36.7%

(1) The tax impact is computed utilizing our effective tax rate on the adjustments for certain non-cash and non-recurring items.

Fair Value of Financial Instruments

See Note 6 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.

Critical Accounting Policies and Estimates

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2013 Annual Report other than those noted below.

Recent accounting pronouncements

Revenue recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP and is effective for interim and annual reporting periods beginning after December 15, 2016. We are currently evaluating the effect that adopting this new guidance will have on our financial position, cash flows and results of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the Securities and Exchange Commission (“SEC”). In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See

Note 14 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 2013 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 June 30, 2014, we utilized two-way and three-way costless collar options, swaps, swaps with sub-floors and deferred premium puts to reduce the volatility of oil prices on a significant portion of our future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be WTI crude oil index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A swap with a sub-floor is a swap coupled with a sold put (sub-floor) at which point the minimum price would be WTI crude oil index price plus the difference between the swap and the sold put strike price. For the deferred premium puts, we agree to pay a premium to the counterparty at the time of settlement. At settlement, if the WTI price is below the floor price of the put, we receive the difference between the floor price and the WTI price multiplied by the contract volumes, less the premium. If the WTI price settles at or above the floor price of the put, we pay only the premium.

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 June 30, 2014:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Weighted Average Prices: Swap ($/Barrel)	Sub-Floor	Floor	Ceiling	Weighted Average Deferred Premium	Fair Value Asset (Liability) (In thousands)
2014	Two-way collars	1,855,500			$94.92	$106.16		$ (3,019)
2014	Three-way collars	1,615,500		$70.57	$90.57	$105.20		(3,774)
2014	Swaps	1,858,500	$96.13					(14,339)
2014	Swaps with sub-floors	1,098,000	$92.60	$70.00				(12,194)
2015	Two-way collars	2,388,500			$87.98	$103.21		(2,738)
2015	Three-way collars	263,500		$70.59	$90.59	$105.25		(489)
2015	Swaps	5,263,500	$90.81					(34,657)
2015	Swaps with sub-floors	186,000	$92.60	$70.00				(1,544)
2015	Deferred premium puts	1,086,000			$90.00		$2.55	(549)
2016	Two-way collars	155,000			$86.00	$103.42		92
2016	Swaps	310,000	$90.15					(1,048)
								$ (74,259)

Interest rate risk. We had (i) $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum, (ii) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum and (iii) $1,400.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum outstanding at June 30, 2014. At June 30, 2014, we had $100.0 million of borrowings and $5.2 million letters of credit outstanding under our Second Amended Credit Facility, which were subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a LIBOR loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or “ABR” loan). At June 30, 2014, the outstanding borrowings under our Second Amended Credit Facility bore interest at LIBOR plus a 1.5% margin. We do not

Table of Contents

currently, but may in the future, utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to debt issued under our Second Amended Credit Facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

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

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

We may, from time to time, purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. Our investment policy requires that our counterparties have minimum credit ratings thresholds and provides maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers being unable to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If a commercial paper issuer is unable to return investment proceeds to us at the maturity date, it could take a significant amount of time to recover all or a portion of the assets originally invested. Our commercial paper balance was $36,000 at June 30, 2014.

Most of the counterparties on our derivative instruments currently in place are lenders under our Second Amended Credit Facility with investment grade ratings. We are likely to enter into future derivative instruments with these or other lenders under our Second Amended Credit Facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative liability position of $74.3 million at June 30, 2014.

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 June 30, 2014. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO, CFO and CAO as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, our CEO, CFO and CAO have concluded that our disclosure controls and

procedures were effective at June 30, 2014.
Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended June 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II — OTHER INFORMATION

Item 1. — Legal Proceedings

See Part I, Item 1, Note 14 to our unaudited condensed consolidated financial statements entitled "Commitments and Contingencies," which is incorporated in this item by reference.

Item 1A. — Risk Factors

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

For a discussion of our potential risks and uncertainties, see the information in Item 1A. "Risk Factors" in our 2013 Annual Report. There have been no material changes in our risk factors from those described in our 2013 Annual Report.

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 June 30, 2014:

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
April 1 - April 30, 2014	1,858	$42.55	—	—
May 1 - May 31, 2014	2,063	45.51	—	—
June 1 - June 30, 2014	2,355	49.54	—	—
Total	6,276	$46.14	—	—

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

Item 6. — Exhibits

Exhibit No.	Description of Exhibit
10.1(a)**	Amended and Restated 2010 Long Term Incentive Plan of Oasis Petroleum Inc.
10.2(a)**	Amended and Restated 2010 Annual Incentive Compensation Plan of Oasis Petroleum Inc.
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.

Table of Contents

(b) Furnished herewith.
** Management contract or compensatory plan or arrangement.

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: August 6, 2014	By:	/s/ Thomas B. Nusz Thomas B. Nusz Chairman 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 and Chief Accounting Officer (Principal Accounting Officer)

Table of Contents

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(b) Furnished herewith.
** Management contract or compensatory plan or arrangement.