Oasis Petroleum Inc.
Form 10-Q
August 07, 2013
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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, 2013
or
.. TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-34776

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

Number of shares of the registrant’s common stock outstanding at August 2, 2013: 93,538,091 shares.

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

	June 30, 2013	December 31, 2012
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$161,601	$213,447
Short-term investments	—	25,891
Accounts receivable — oil and gas revenues	130,518	110,341
Accounts receivable — joint interest partners	92,785	99,194
Inventory	16,385	20,707
Prepaid expenses	6,121	1,770
Advances to joint interest partners	1,319	1,985
Derivative instruments	7,353	19,016
Other current assets	5	335
Total current assets	416,087	492,686
Property, plant and equipment		
Oil and gas properties (successful efforts method)	2,675,902	2,348,128
Other property and equipment	144,518	49,732
Less: accumulated depreciation, depletion, amortization and impairment	(514,567)	(391,260)
Total property, plant and equipment, net	2,305,853	2,006,600
Derivative instruments	10,554	4,981
Deferred costs and other assets	25,650	24,527
Total assets	$2,758,144	$2,528,794
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$30,682	$12,491
Advances from joint interest partners	15,583	21,176
Revenues and production taxes payable	102,661	71,553
Accrued liabilities	180,988	189,863
Accrued interest payable	29,133	30,096
Derivative instruments	—	1,048
Deferred income taxes	1,030	4,558
Other current liabilities	688	—
Total current liabilities	360,765	330,785
Long-term debt	1,200,000	1,200,000
Asset retirement obligations	26,268	22,956
Derivative instruments	291	380
Deferred income taxes	249,172	177,671
Other liabilities	2,435	1,997
Total liabilities	1,838,931	1,733,789
Commitments and contingencies (Note 13)		
Stockholders' equity		
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,693,829 issued and 93,554,121 outstanding at June 30, 2013; 93,432,712 issued and 93,303,298 outstanding at December 31, 2012	925	925

Treasury stock, at cost; 139,708 and 129,414 shares at June 30, 2013 and December 31, 2012, respectively	(4,160)	(3,796)
Additional paid-in-capital	663,545	657,943
Retained earnings	258,903	139,933
Total stockholders' equity	919,213	795,005
Total liabilities and stockholders' equity	$2,758,144	$2,528,794

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$241,842	$145,203	$483,493	$283,109
Well services and midstream revenues	12,740	3,861	19,393	4,521
Total revenues	254,582	149,064	502,886	287,630
Expenses				
Lease operating expenses	18,266	12,029	37,755	21,845
Well services and midstream operating expenses	6,644	1,207	9,558	1,684
Marketing, transportation and gathering expenses	10,779	1,970	14,168	4,539
Production taxes	21,397	13,720	43,486	26,986
Depreciation, depletion and amortization	66,790	44,213	133,051	83,099
Exploration expenses	392	—	2,249	2,835
Impairment of oil and gas properties	208	2,203	706	2,571
General and administrative expenses	16,656	13,537	30,510	25,736
Total expenses	141,132	88,879	271,483	169,295
Operating income	113,450	60,185	231,403	118,335
Other income (expense)				
Net gain (loss) on derivative instruments	12,591	74,595	(2,021)	56,009
Interest expense, net of capitalized interest	(21,392)	(14,074)	(42,575)	(27,973)
Other income	294	776	1,074	1,374
Total other income (expense)	(8,507)	61,297	(43,522)	29,410
Income before income taxes	104,943	121,482	187,881	147,745
Income tax expense	37,824	45,439	68,911	55,261
Net income	$67,119	$76,043	$118,970	$92,484
Earnings per share:				
Basic (Note 11)	$0.73	$0.82	$1.29	$1.00
Diluted (Note 11)	0.72	0.82	1.28	1.00
Weighted average shares outstanding:				
Basic (Note 11)	92,399	92,176	92,387	92,153
Diluted (Note 11)	92,702	92,222	92,812	92,339

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

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

	Common Stock		Treasury Stock		Additional Paid-in-Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
Balance as of December 31, 2012	93,303	$925	129	$(3,796)	$ 657,943	$ 139,933	$795,005
Stock-based compensation	261	—	—	—	5,602	—	5,602
Treasury stock – tax withholdings	(10)	—	10	(364)	—	—	(364)
Net income	—	—	—	—	—	118,970	118,970
Balance as of June 30, 2013	93,554	$925	139	$(4,160)	$ 663,545	$ 258,903	$919,213

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

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

	Six Months Ended June 30,	
	2013	2012
	(In thousands)	
Cash flows from operating activities:		
Net income	$118,970	$92,484
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	133,051	83,099
Impairment of oil and gas properties	706	2,571
Deferred income taxes	67,974	55,161
Derivative instruments	2,021	(56,009)
Stock-based compensation expenses	5,371	3,898
Debt discount amortization and other	1,753	1,265
Working capital and other changes:		
Change in accounts receivable	(13,768)	(26,840)
Change in inventory	(4,200)	(21,636)
Change in prepaid expenses	(4,402)	1,500
Change in other current assets	330	490
Change in other assets	—	(7,365)
Change in accounts payable and accrued liabilities	48,701	40,022
Change in other current liabilities	688	2,470
Change in other liabilities	612	750
Net cash provided by operating activities	357,807	171,860
Cash flows from investing activities:		
Capital expenditures	(429,296)	(440,781)
Derivative settlements	2,932	(2,465)
Redemptions of short-term investments	25,000	19,994
Advances to joint interest partners	666	1,978
Advances from joint interest partners	(5,593)	19,380
Net cash used in investing activities	(406,291)	(401,894)
Cash flows from financing activities:		
Purchases of treasury stock	(364)	(1,206)
Debt issuance costs	(2,998)	(746)
Net cash used in financing activities	(3,362)	(1,952)
Decrease in cash and cash equivalents	(51,846)	(231,986)
Cash and cash equivalents:		
Beginning of period	213,447	470,872
End of period	$161,601	$238,886
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$(6,085)	$104,486
Change in asset retirement obligations	3,441	4,185

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

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OASIS PETROLEUM INC.
Notes to Condensed Consolidated Financial Statements (Unaudited)
1. Organization and Operations of the Company
Organization
Oasis Petroleum Inc. (together with its subsidiaries, "Oasis" or the "Company") was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a holding company for Oasis Petroleum LLC ("OP LLC"), the Company's predecessor, which was formed as a Delaware limited liability company on February 26, 2007. In connection with its initial public offering in June 2010 and related corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company's common stock. In 2007, Oasis Petroleum North America LLC ("OPNA"), a Delaware limited liability company, was formed to conduct domestic oil and natural gas exploration and production activities. In 2008, Oasis Petroleum International LLC ("OPI"), a Delaware limited liability company, was formed to conduct business development activities outside of the United States of America. As of June 30, 2013, OPI had no business activities or material assets. In 2011, the Company formed Oasis Well Services LLC ("OWS"), a Delaware limited liability company, to provide well services to OPNA, and Oasis Petroleum Marketing LLC ("OPM"), a Delaware limited liability company, to provide marketing services to OPNA. In 2013, the Company formed Oasis Midstream Services LLC ("OMS"), a Delaware limited liability company, to provide midstream services to OPNA. As part of the formation of OMS, the Company transferred substantially all of its salt water disposal and other midstream assets from OPNA to OMS.
Nature of Business
The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the Williston Basin. The Company's proved and unproved oil and natural gas properties are located in the Montana and North Dakota areas of the Williston Basin and are owned by OPNA. The Company also operates a marketing business (OPM), a well services business (OWS) and a midstream services business (OMS), all of which are complementary to its primary development and production activities. Both OWS and OMS are separate reportable business segments.
2. Summary of Significant Accounting Policies
Basis of Presentation
The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly owned subsidiaries. The accompanying condensed consolidated financial statements of the Company have not been audited by the Company's independent registered public accounting firm, except that the condensed consolidated balance sheet at December 31, 2012 is derived from audited financial statements. All significant intercompany transactions have been eliminated in consolidation. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for the fair presentation, have been included. In preparing the accompanying condensed consolidated financial statements, management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.
These interim financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America ("GAAP") for complete consolidated financial statements and should be read in conjunction with the Company's audited consolidated financial statements and notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2012 ("2012 Annual Report").
Significant Accounting Policies
There have been no material changes to the Company's critical accounting policies and estimates from those disclosed in the 2012 Annual Report.
3. Inventory
Equipment and materials consist primarily of tubular goods, well equipment to be used in future drilling or repair operations, well fracturing equipment, chemicals and proppant, all of which are stated at the lower of cost or market

with cost determined on an average cost method. Crude oil inventories include oil in tank and line fill and are valued at the lower of average cost or market value. Inventory consists of the following:

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	June 30, 2013	December 31, 2012
	(In thousands)	
Equipment and materials	$10,562	$16,438
Crude oil inventory	5,823	4,269
Total inventory	$16,385	$20,707

4. Property, Plant and Equipment

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

	June 30, 2013	December 31, 2012
	(In thousands)	
Proved oil and gas properties (1)	$2,608,460	$2,271,711
Less: Accumulated depreciation, depletion, amortization and impairment	(498,007)	(383,564)
Proved oil and gas properties, net (2)	2,110,453	1,888,147
Unproved oil and gas properties	67,442	76,417
Total oil and gas properties, net	2,177,895	1,964,564
Other property and equipment	144,518	49,732
Less: Accumulated depreciation	(16,560)	(7,696)
Other property and equipment, net (2)	127,958	42,036
Total property, plant and equipment, net	$2,305,853	$2,006,600

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $26.3 million and $20.7 million at June 30, 2013 and December 31, 2012, respectively.

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

As a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $0.2 million and $0.7 million for the three and six months ended June 30, 2013, respectively, and $2.2 million and $2.6 million for the three and six months ended June 30, 2012, respectively. No impairment charges on proved oil and natural gas properties were recorded for the three and six months ended June 30, 2013 or 2012.

5. Fair Value Measurements

In accordance with the Financial Accounting Standards Board's ("FASB") authoritative guidance on fair value measurements, the Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

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

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

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using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument and can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

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

Financial Assets and Liabilities

As required, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The following tables set forth by level within the fair value hierarchy the Company's financial assets and liabilities that were accounted for at fair value on a recurring basis:

	At fair value as of June 30, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$36,442	$—	$—	$36,442
Commodity derivative instruments (see Note 6)	—	17,907	—	17,907
Total assets	$36,442	$17,907	$—	$54,349
Liabilities:				
Commodity derivative instruments (see Note 6)	$—	$291	$—	$291
Total liabilities	$—	$291	$—	$291

	At fair value as of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$66,387	$—	$—	$66,387
Commodity derivative instruments (see Note 6)	—	23,997	—	23,997
Total assets	$66,387	$23,997	$—	$90,384
Liabilities:				
Commodity derivative instruments (see Note 6)	$—	$1,428	$—	$1,428
Total liabilities	$—	$1,428	$—	$1,428

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, 2013 and December 31, 2012. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identified the money market funds as Level 1 instruments due to the fact that the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained and there are active markets for the underlying investments.

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include oil collars, swaps and puts. The fair values of the Company's commodity derivative instruments are based upon a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The Company compares the third-party preparer's valuation to counterparty valuation statements, investigating any significant differences, and analyzes monthly valuation changes in relation to movements in crude oil forward price curves. The determination of the fair value for derivative instruments also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in a net asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a net liability position is based on the Company’s market credit spread. Based on these calculations, the Company recorded downward adjustments to the fair value of its net derivative asset in the amounts of $76,000 and $29,000 at June 30, 2013 and December 31, 2012, respectively.

Fair Value of Other Financial Instruments

The Company’s financial instruments, including certain cash and cash equivalents, short-term investments, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At June 30, 2013, the Company’s cash equivalents and short-term investments were all Level 1 assets. The carrying amount of the Company’s long-term debt (senior unsecured notes due 2019, 2021 and 2023 – see Note 7) reported in the Condensed Consolidated Balance Sheet at June 30, 2013 is $1,200.0 million with a fair value of $1,239.0 million. The Company’s senior unsecured notes are publicly traded and therefore categorized as a Level 1 liability.

Nonfinancial Assets and Liabilities

Asset retirement obligations. The carrying amount of the Company’s asset retirement obligations (“ARO”) in the Condensed Consolidated Balance Sheet at June 30, 2013 is $26.7 million (see Note 8 – Asset Retirement Obligations). The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments, including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

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

6. Derivative Instruments

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

All derivative instruments are recorded on the balance sheet as either assets or liabilities measured at fair value (see Note 5 – Fair Value Measurements). Derivative assets and liabilities arising from the Company's derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value, both realized and unrealized, are recognized in the other income (expense) section of the Condensed Consolidated

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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 or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company’s Condensed Consolidated Statement of Cash Flows.

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

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices Swap	Sub-Floor	Floor	Ceiling	Fair Value Asset (Liability)
		(Barrels)	($/Barrel)				(In thousands)
2013	Two-way collars	1,006,500			$86.82	$97.75	$(985)
2013	Three-way collars	1,121,790		$65.92	92.45	111.45	1,898
2013	Put spreads	906,210		70.93	91.09		1,364
2013	Swaps	1,464,000	$95.40				(255)
2014	Two-way collars	504,500			88.92	95.86	682
2014	Three-way collars	2,695,030		70.33	90.79	106.21	9,870
2014	Put spreads	150,970		71.03	91.03		576
2014	Swaps	1,083,000	93.04				2,290
2014	Swaps with sub-floors	1,336,000	92.03	70.00			318
2015	Two-way collars	31,000			90.00	94.90	137
2015	Three-way collars	232,500		70.67	90.67	105.81	1,114
2015	Swaps	77,500	92.34				363
2015	Swaps with sub-floors	124,000	92.03	70.00			244
							$17,616

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

Fair Value of Derivative Instrument Assets (Liabilities)

Commodity	Balance Sheet Location	Fair Value June 30, 2013	December 31, 2012
		(In thousands)	
Crude oil	Derivative instruments — current assets	$7,353	$19,016
Crude oil	Derivative instruments — non-current assets	10,554	4,981
Crude oil	Derivative instruments — current liabilities	—	(1,048)
Crude oil	Derivative instruments — non-current liabilities	(291)	(380)
Total derivative instruments		$17,616	$22,569

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

	Income Statement Location	Three Months Ended June 30, 2013	2012	Six Months Ended June 30, 2013	2012
		(In thousands)			
Change in unrealized gain (loss) on derivative instruments	Net gain (loss) on derivative instruments	$11,345	$75,769	$(4,953)	$58,474

Derivative settlements	Net gain (loss) on derivative instruments	1,246	(1,174)	2,932	(2,465)
Total net gain (loss) on derivative instruments		$12,591	$74,595	$(2,021)	$56,009

The Company has adopted the FASB’s authoritative guidance on disclosures about offsetting assets and liabilities, which requires entities to disclose both gross and net information about instruments and transactions eligible for offset in the

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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

Derivative Instruments	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, 2013	$44,565	$ (26,658)	$ 17,907
As of December 31, 2012	68,970	(44,973)	23,997

Offsetting of Derivative Liabilities

Derivative Instruments	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, 2013	$26,949	$ (26,658)	$ 291
As of December 31, 2012	46,401	(44,973)	1,428

7. Long-Term Debt

Senior unsecured notes. The Company issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 and $400.0 million of 6.5% senior unsecured notes due November 1, 2021 during 2011 and $400.0 million of 6.875% senior unsecured notes due January 15, 2023 during 2012 (collectively, the "Notes"). Interest on the Notes is payable semi-annually in arrears. The issuance of these Notes resulted in aggregate net proceeds to the Company of approximately $1,175.8 million. The Company is using the proceeds from the Notes to fund its exploration, development and acquisition program and for general corporate purposes. The Notes are guaranteed on a senior unsecured basis by the Company's material subsidiaries (the "Guarantors"). These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions, as follows:

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

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

The Indentures restrict the Company’s ability and the ability of certain of its subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain

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

The Indentures contain customary events of default, including:

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

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 October 6, 2016. In connection with entry into the Second Amended Credit Facility, the semi-annual redetermination of the Company's borrowing base was also completed on April 5, 2013, which resulted in an increase to the borrowing base of the Second Amended Credit Facility from $750 million to $1.25 billion. However, the Company elected to limit the aggregate commitment of the lenders under the Second Amended Credit Facility (the "Lenders") to $900 million. The Company may increase its aggregate commitment to the full $1.25 billion borrowing base by increasing the commitment of one or more lenders. In addition, under the Second Amended Credit Facility, the overall credit facility increased from $1.0 billion to $2.5 billion, and the Company added four new lenders to the bank group.

The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. Borrowings under the Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

Borrowings under the Second Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate ("LIBOR") loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or "ABR" loan). As of June 30, 2013, any outstanding LIBOR and ABR loans would have borne their respective interest rates plus the applicable margin indicated in the following table:

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

Greater than .90 to 1 but less than or equal 1	2.50 %	1.00 %

An ABR loan may be repaid at any time before the scheduled maturity of the 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, 2013) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

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

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

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

As of June 30, 2013, the Company had no borrowings and $2.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base capacity of $897.8 million. The Company was in compliance with the financial covenants of the Second Amended Credit Facility as of June 30, 2013.

Deferred financing costs. As of June 30, 2013, the Company had $24.6 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, 2013 and are being amortized over the respective terms of the Notes and the Second Amended Credit Facility. Amortization of deferred financing costs recorded for the three and six months ended June 30, 2013 was $1.0 million and $1.9 million, respectively, and $0.7 million and $1.3 million for the three and six months ended June 30, 2012, respectively. These costs are included in interest expense on the Company’s Condensed Consolidated Statement of Operations.

8. Asset Retirement Obligations

The following table reflects the changes in the Company’s ARO during the six months ended June 30, 2013:

	(In thousands)
Balance at December 31, 2012	$23,234
Liabilities incurred during period	2,635
Liabilities settled during period	23
Accretion expense during period (1)	581
Revisions to estimates	227
Balance at June 30, 2013	$26,700

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

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

9. Stock-Based Compensation

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

Stock-based compensation expense recorded for restricted stock awards for the three and six months ended June 30, 2013 was $2.6 million and $4.6 million, respectively. For the three and six months ended June 30, 2012, stock-based compensation expense recorded for restricted stock awards was $2.3 million and $3.9 million, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

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

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

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

	PSUs	Weighted Average Grant Date Fair Value per Unit
Non-vested PSUs at December 31, 2012	155,220	$ 26.22
Granted	135,620	42.01
Vested	—	—
Forfeited	(10,770)	32.89
Non-vested PSUs at June 30, 2013	280,070	$ 33.61

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

The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions for the Monte Carlo model are the forecast period, initial value, risk-free rate, volatility and correlation coefficients. The risk-free rate is the U.S. treasury rate on the date of grant. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage in stock price over a

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historical two-year period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data. Beginning January 1, 2013, the Company assumed an annual forfeiture rate of 2.7% based on management's expectations of forfeitures for all PSUs granted.

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

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

Based on these assumptions, the Monte Carlo simulation model resulted in an expected percentage of PSUs earned of 112% and 98% for the 2013 and 2012 grants, respectively. Stock-based compensation expense recorded for these PSUs for the three and six months ended June 30, 2013 was $0.5 million and $0.8 million, respectively, and is included in general and administrative expenses on the Condensed Consolidated Statement of Operations. No stock-based compensation expense related to PSUs was recorded for the three and six months ended June 30, 2012 as the Company had not issued PSUs prior to July 2012.

10. Income Taxes

The Company's effective tax rate for the three and six months ended June 30, 2013 was 36.0% and 36.7%, respectively. The Company's effective tax rate for the three and six months ended June 30, 2012 was 37.4%. 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, 2013, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

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

11. Earnings Per Share

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(In thousands)			
Basic weighted average common shares outstanding	92,399	92,176	92,387	92,153
Dilution effect of stock awards at end of period	303	46	425	186
Diluted weighted average common shares outstanding	92,702	92,222	92,812	92,339
Anti-dilutive stock-based compensation awards	914	634	711	397

12. Business Segment Information

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

Management evaluates the performance of the Company's business segments based on operating income, which is defined as segment operating revenues less expenses. Summarized financial information for the Company's segments is shown in the following table:

	Exploration and Production (In thousands)	Well Services	Midstream Services	Consolidated
Three Months Ended 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
Three Months Ended June 30, 2012:				
Revenues	$145,203	$16,505	$—	$161,708
Inter-segment revenues	—	(12,644)	—	(12,644)
Total revenues	145,203	3,861	—	149,064
Operating income	58,735	1,450	—	60,185
Other income (expense)	61,297	—	—	61,297
Income before income taxes	120,032	1,450	—	121,482
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
Six Months Ended June 30, 2012:				
Revenues	$283,109	$17,749	$—	$300,858
Inter-segment revenues	—	(13,228)	—	(13,228)
Total revenues	283,109	4,521	—	287,630
Operating income	100,978	17,357	—	118,335
Other income (expense)	29,410	—	—	29,410

Income before income taxes	130,388	17,357	—	147,745
Total Assets:				
As of June 30, 2013	$2,617,366	$52,209	$88,569	$2,758,144
As of December 31, 2012	2,475,820	52,974	—	2,528,794

13. Commitments and Contingencies

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Lease obligations. The Company's total rental commitments under leases for office space and other property and equipment at June 30, 2013 were $12.2 million.
Drilling contracts. As of June 30, 2013, the Company had certain drilling rig contracts with initial terms greater than one year. In the event of early contract termination under these contracts, the Company would be obligated to pay approximately $30.2 million as of June 30, 2013 for the days remaining through the end of the primary terms of the contracts.
Volume commitment agreements. As of June 30, 2013, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of approximately 18.2 MMBbl and 13.6 Bcf from its Williston Basin project areas within specified timeframes, all of which are less than six years. Future obligations under these agreements were approximately $61.1 million as of June 30, 2013.
Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. The Company believes all such matters are without merit and involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows.

14. Condensed Consolidating Financial Information
The Notes (see Note 7) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company's immaterial wholly owned subsidiaries do not guarantee the Notes ("Non-Guarantor Subsidiaries").
The following financial information reflects consolidating financial information of the Company ("Issuer") and its Guarantors on a combined basis, prepared on the equity basis of accounting. The Non-Guarantor Subsidiaries are immaterial and, therefore, not presented separately. The information is presented in accordance with the requirements of Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations, cash flows or financial position had the Guarantors operated as independent entities. The Company has not presented separate financial and narrative information for each of the Guarantors because it believes such financial and narrative information would not provide any additional information that would be material in evaluating the sufficiency of the Guarantors.
Condensed Consolidating Balance Sheet
(In thousands, except share data)

	June 30, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$83,770	$77,831	$—	$161,601
Accounts receivable – oil and gas revenues	—	130,518	—	130,518
Accounts receivable – joint interest partners	—	92,785	—	92,785
Accounts receivable – from affiliates	771	6,511	(7,282)	—
Inventory	—	16,385	—	16,385
Prepaid expenses	—	6,121	—	6,121
Advances to joint interest partners	—	1,319	—	1,319
Derivative instruments	—	7,353	—	7,353
Other current assets	3	2	—	5
Total current assets	84,544	338,825	(7,282)	416,087
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	2,675,902	—	2,675,902
Other property and equipment	—	144,518	—	144,518

Less: accumulated depreciation, depletion, amortization and impairment	—	(514,567)	—	(514,567)
Total property, plant and equipment, net	—	2,305,853	—	2,305,853
Investments in and advances to subsidiaries	1,990,470	—	(1,990,470)	—
Derivative instruments	—	10,554	—	10,554
Deferred income taxes	60,406	—	(60,406)	—
Deferred costs and other assets	19,450	6,200	—	25,650
Total assets	$2,154,870	$2,661,432	$(2,058,158)	$2,758,144
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable	$22	$30,660	$—	$30,682
Accounts payable – from affiliates	6,511	771	(7,282)	—
Advances from joint interest partners	—	15,583	—	15,583
Revenues and production taxes payable	—	102,661	—	102,661
Accrued liabilities	27	180,961	—	180,988
Accrued interest payable	29,097	36	—	29,133
Deferred income taxes	—	1,030	—	1,030
Other current liabilities	—	688	—	688
Total current liabilities	35,657	332,390	(7,282)	360,765
Long-term debt	1,200,000	—	—	1,200,000
Asset retirement obligations	—	26,268	—	26,268
Derivative instruments	—	291	—	291
Deferred income taxes	—	309,578	(60,406)	249,172
Other liabilities	—	2,435	—	2,435
Total liabilities	1,235,657	670,962	(67,688)	1,838,931
Stockholders' equity				
Capital contributions from affiliates	—	1,621,489	(1,621,489)	—
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,693,829 issued and 93,554,121 outstanding	925	—	—	925
Treasury stock, at cost; 139,708 shares	(4,160)	—	—	(4,160)
Additional paid-in-capital	663,545	8,743	(8,743)	663,545
Retained earnings	258,903	360,238	(360,238)	258,903
Total stockholders' equity	919,213	1,990,470	(1,990,470)	919,213
Total liabilities and stockholders' equity	$2,154,870	$2,661,432	$(2,058,158)	$2,758,144

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

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

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

Condensed Consolidating Statement of Operations
(In thousands)

	Three Months Ended 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	(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)

	Three Months Ended June 30, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$145,203	$—	$145,203
Well services revenues	—	3,861	—	3,861
Total revenues	—	149,064	—	149,064
Expenses				
Lease operating expenses	—	12,029	—	12,029
Well services operating expenses	—	1,207	—	1,207
Marketing, transportation and gathering expenses	—	1,970	—	1,970
Production taxes	—	13,720	—	13,720
Depreciation, depletion and amortization	—	44,213	—	44,213

Impairment of oil and gas properties	—	2,203	—	2,203
General and administrative expenses	2,644	10,893	—	13,537
Total expenses	2,644	86,235	—	88,879
Operating income (loss)	(2,644)	62,829	—	60,185
Other income (expense)				
Equity in earnings in subsidiaries	86,024	—	(86,024)	—
Net gain on derivative instruments	—	74,595	—	74,595
Interest expense, net of capitalized interest	(13,414)	(660)	—	(14,074)
Other income	118	658	—	776
Total other income (expense)	72,728	74,593	(86,024)	61,297
Income before income taxes	70,084	137,422	(86,024)	121,482
Income tax benefit (expense)	5,959	(51,398)	—	(45,439)
Net income	$76,043	$86,024	$(86,024)	$76,043

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	(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

Condensed Consolidating Statement of Operations
(In thousands)

	Six Months Ended June 30, 2012			
	Parent/	Combined	Intercompany	Consolidated

	Issuer	Guarantor Subsidiaries	Eliminations	
Revenues				
Oil and gas revenues	$—	$283,109	$—	$283,109
Well services and midstream revenues	—	4,521	—	4,521
Total revenues	—	287,630	—	287,630
Expenses				
Lease operating expenses	—	21,845	—	21,845
Well services and midstream operating expenses	—	1,684	—	1,684
Marketing, transportation and gathering expenses	—	4,539	—	4,539
Production taxes	—	26,986	—	26,986
Depreciation, depletion and amortization	—	83,099	—	83,099
Exploration expenses	—	2,835	—	2,835
Impairment of oil and gas properties	—	2,571	—	2,571
General and administrative expenses	5,090	20,646	—	25,736
Total expenses	5,090	164,205	—	169,295
Operating income (loss)	(5,090)	123,425	—	118,335
Other income (expense)				
Equity in earnings in subsidiaries	112,286	—	(112,286)	—
Net gain on derivative instruments	—	56,009	—	56,009
Interest expense, net of capitalized interest	(26,829)	(1,144)	—	(27,973)
Other income	295	1,079	—	1,374
Total other income (expense)	85,752	55,944	(112,286)	29,410
Income before income taxes	80,662	179,369	(112,286)	147,745
Income tax benefit (expense)	11,822	(67,083)	—	(55,261)
Net income	$92,484	$112,286	$(112,286)	$92,484

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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	—	(429,296)	—	(429,296)
Derivative settlements	—	2,932	—	2,932
Redemptions of short-term investments	25,000	—	—	25,000
Advances to joint interest partners	—	666	—	666
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

Condensed Consolidating Statement of Cash Flows
(In thousands)

	Six Months Ended June 30, 2012			
	Parent/	Combined	Intercompany	Consolidated

	Issuer	Guarantor Subsidiaries	Eliminations	
Cash flows from operating activities:				
Net income	$92,484	$112,286	$(112,286)	$92,484
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(112,286)	—	112,286	—
Depreciation, depletion and amortization	—	83,099	—	83,099
Impairment of oil and gas properties	—	2,571	—	2,571
Deferred income taxes	(11,822)	66,983	—	55,161
Derivative instruments	—	(56,009)	—	(56,009)
Stock-based compensation expenses	3,793	105	—	3,898
Debt discount amortization and other	960	305	—	1,265
Working capital and other changes:				
Change in accounts receivable	(178)	(28,661)	1,999	(26,840)
Change in inventory	—	(21,636)	—	(21,636)
Change in prepaid expenses	246	1,254	—	1,500
Change in other current assets	17	473	—	490
Change in other assets	(7,305)	(60)	—	(7,365)
Change in accounts payable and accrued liabilities	9,657	32,364	(1,999)	40,022
Change in other current liabilities	—	2,470	—	2,470
Change in other liabilities	—	750	—	750
Net cash provided by (used in) operating activities	(24,434)	196,294	—	171,860
Cash flows from investing activities:				
Capital expenditures	—	(440,781)	—	(440,781)
Derivative settlements	—	(2,465)	—	(2,465)
Redemptions of short-term investments	19,994	—	—	19,994
Advances to joint interest partners	—	1,978	—	1,978
Advances from joint interest partners	—	19,380	—	19,380
Net cash provided by (used in) investing activities	19,994	(421,888)	—	(401,894)
Cash flows from financing activities:				
Purchases of treasury stock	(1,206)	—	—	(1,206)
Debt issuance costs	(46)	(700)	—	(746)
Investment in / capital contributions from affiliates	(242,130)	242,130	—	—
Net cash provided by (used in) financing activities	(243,382)	241,430	—	(1,952)
Increase (decrease) in cash and cash equivalents	(247,822)	15,836	—	(231,986)
Cash and cash equivalents at beginning of period	443,482	27,390	—	470,872
Cash and cash equivalents at end of period	$195,660	$43,226	$—	$238,886

15. Subsequent Events

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

Derivative instruments. In July 2013, the Company entered into new three-way collar options, swaps and swaps with sub-floors, which settle monthly based on the WTI crude oil index price, for a total notional amount of 1,879,000 barrels in 2014 and 124,000 barrels in 2015. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

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Drilling contracts. In July 2013, the Company extended one of its existing drilling rig contracts for an additional year. In the event of early contract termination under this extended contract, the Company would be obligated to pay an additional maximum of approximately $4.8 million if terminated immediately after execution.

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

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

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Quarterly Report on Form 10-Q, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Quarterly Report on Form 10-Q, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed below and detailed under Item 1A. "Risk Factors" in our 2012 Annual Report could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about:

- our business strategy;
- estimated future net reserves and present value thereof;
- technology;
- cash flows and liquidity;
- our financial strategy, budget, projections, execution of business plan and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling, completion and production equipment and materials;
- availability of qualified personnel;
- owning and operating well services and midstream companies;
- the amount, nature and timing of capital expenditures;
- availability and terms of capital;
- property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- drilling and completion of wells;
- estimated inventory of wells remaining to be drilled and completed;
- infrastructure for salt water disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- general economic conditions;
- operating environment, including inclement weather conditions;
- competition in the oil and natural gas industry;
- effectiveness of risk management activities;
- environmental liabilities;
- counterparty credit risk;
- governmental regulation and the taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- uncertainty regarding future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report on Form 10-Q are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Quarterly Report on Form 10-Q, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Overview

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

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

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

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

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

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

Changes in commodity prices may also significantly affect the economic viability of drilling projects and economic recovery of oil and gas reserves. As a result of higher commodity prices and continued successes in the application of completion technologies in the Bakken formation, there were approximately 192 active drilling rigs in the Williston Basin at

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June 30, 2013. Both production and takeaway capacity have rapidly grown in the Williston Basin throughout 2012 and the first half of 2013. In the first half of 2012, price differentials were at or above the historical average discount range of 10% to 15% to the price quoted for NYMEX West Texas Intermediate ("WTI") crude oil due to production growth in the Williston Basin combined with refinery and transportation constraints. In the third quarter of 2012, our price differentials relative to WTI began to narrow, primarily due to transportation capacity additions, including expanded rail infrastructure and pipeline expansions, outpacing production growth. In the fourth quarter of 2012 and into the first quarter of 2013, average price differentials continued to narrow, primarily due to our ability to access premium coastal markets by rail. As the premium at coastal markets contracted during the second quarter of 2013, our price differentials relative to WTI increased. More recently, as pricing on pipelines has become more attractive relative to pricing on rail, we began transporting more of our crude oil volumes by pipeline.

Second Quarter 2013 Highlights:

- We completed and placed on production 20 gross (14.0 net) operated wells in the Williston Basin during the three months ended June 30, 2013;
- We had 37 gross operated wells awaiting completion and 11 gross operated wells in the process of being drilled in the Bakken and Three Forks formations at June 30, 2013;
- Average daily production was 30,171 Boe per day during the three months ended June 30, 2013;
- E&P capital expenditures were $189.0 million, consisting primarily of $184.1 million in drilling and completion expenditures during the three months ended June 30, 2013; and
- At June 30, 2013, we had $161.6 million of cash and cash equivalents. We had no outstanding borrowings and had $2.2 million of outstanding letters of credit under our revolving credit facility.

Results of Operations

Revenues

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

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	Change	2013	2012	Change
Operating results (in thousands):						
Revenues						
Oil	$232,625	$138,559	$94,066	$464,300	$269,935	$194,365
Natural gas	9,217	6,644	2,573	19,193	13,174	6,019
Well services and midstream	12,740	3,861	8,879	19,393	4,521	14,872
Total revenues	254,582	149,064	105,518	502,886	287,630	215,256
Production data:						
Oil (MBbls)	2,489	1,682	807	4,971	3,156	1,815
Natural gas (MMcf)	1,540	1,019	521	2,929	1,803	1,126
Oil equivalents (MBoe)	2,746	1,852	894	5,459	3,457	2,002
Average daily production (Boe/d)	30,171	20,353	9,818	30,162	18,993	11,169
Average sales prices:						
Oil, without realized derivatives (per Bbl) (1)	$91.15	$82.36	$8.79	$92.24	$85.04	$7.20
Oil, with realized derivatives (per Bbl) (1) (2)	91.65	81.67	9.98	92.83	84.26	8.57
Natural gas (per Mcf) (3)	5.98	6.52	(0.54)	6.55	7.30	(0.75)

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

for the six months ended June 30, 2012.

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

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

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

Total revenues. Our total revenues increased $105.5 million or 71%, to $254.6 million during the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 9,818 Boe per day, or 48%, to 30,171 Boe per day during the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The increase in average daily production sold was primarily a result of our well completions during the twelve months ended June 30, 2013, offsetting the decline in production in wells that were producing as of June 30, 2012. Average daily production in our East Nesson, West Williston and Sanish project areas increased by approximately 4,874 Boe per day, 4,484 Boe per day and 460 Boe per day, respectively, during the second quarter of 2013 as compared to the second quarter of 2012. Average oil sales prices, without realized derivatives, increased by $8.79/Bbl to an average of $91.15/Bbl for the three months ended June 30, 2013 as compared to the three months ended June 30, 2012. The higher production amounts sold increased revenues by $76.6 million, while higher oil prices, offset by a slight decrease in natural gas prices, increased revenues by $14.2 million during the three months ended June 30, 2013 compared to the three months ended June 30, 2012. In addition, there was a $5.8 million bulk oil sale related to marketing activities included in oil revenues during the three months ended June 30, 2013. There were no bulk oil sales in the three months ended June 30, 2012.

Well services revenues increased $7.6 million for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 due to an increase in well completion activity and related product sales. Midstream revenues totaled $1.3 million for the three months ended June 30, 2013. There were no midstream revenues during the second quarter of 2012 because OMS did not commence activity until the first quarter of 2013. Prior to 2013, the salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA’s operated wells only, as work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation.

Six months ended June 30, 2013 as compared to six months ended June 30, 2012

Total revenues. Our total revenues increased $215.3 million or 75%, to $502.9 million during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 11,169 Boe per day, or 59%, to 30,162 Boe per day during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. The increase in average daily production sold was primarily a result of our well completions during the twelve months ended June 30, 2013, offsetting the decline in production in wells that were producing as of June 30, 2012. Average daily production in our West Williston, East Nesson and Sanish project areas increased by approximately 5,686 Boe per day, 4,861 Boe per day and 622 Boe per day, respectively, during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. Average oil sales prices, without realized derivatives, increased by $7.20/Bbl to an average of $92.24/Bbl for the six months ended June 30, 2013 as compared to the six months ended June 30, 2012. The higher production amounts sold increased revenues by $174.8 million, while higher oil prices, offset by a slight decrease in natural gas sales prices, increased revenues by $21.3 million during the six months ended June 30, 2013 compared to the six months ended June 30, 2012. In addition, bulk oil sales related to marketing activities included in oil revenues increased $4.3 million during the six months ended June 30, 2013 as compared to the six months ended June 30, 2012.

Well services revenues increased $12.7 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 due to an increase in well completion activity and related product sales. Midstream revenues totaled $2.2 million for the six months ended June 30, 2013. There were no midstream revenues during 2012 because OMS did not commence activity until the first quarter of 2013. Prior to 2013, the salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA’s operated wells only, as work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation.

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Expenses

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2013	2012	$ Change	2013	2012	$ Change
Expenses:						
Lease operating expenses (1)	$18,266	$12,029	$6,237	$37,755	$21,845	$15,910
Well services and midstream operating expenses	6,644	1,207	5,437	9,558	1,684	7,874
Marketing, transportation and gathering expenses	10,779	1,970	8,809	14,168	4,539	9,629
Production taxes	21,397	13,720	7,677	43,486	26,986	16,500
Depreciation, depletion and amortization	66,790	44,213	22,577	133,051	83,099	49,952
Exploration expenses	392	—	392	2,249	2,835	(586)
Impairment of oil and gas properties	208	2,203	(1,995)	706	2,571	(1,865)
General and administrative expenses	16,656	13,537	3,119	30,510	25,736	4,774
Total expenses	141,132	88,879	52,253	271,483	169,295	102,188
Operating income	113,450	60,185	53,265	231,403	118,335	113,068
Other income (expense):						
Net gain (loss) on derivative instruments	12,591	74,595	(62,004)	(2,021)	56,009	(58,030)
Interest expense, net of capitalized interest	(21,392)	(14,074)	(7,318)	(42,575)	(27,973)	(14,602)
Other income	294	776	(482)	1,074	1,374	(300)
Total other income (expense)	(8,507)	61,297	(69,804)	(43,522)	29,410	(72,932)
Income before income taxes	104,943	121,482	(16,539)	187,881	147,745	40,136
Income tax expense	37,824	45,439	(7,615)	68,911	55,261	13,650
Net income	$67,119	$76,043	$(8,924)	$118,970	$92,484	$26,486
Cost and expense (per Boe of production):						
Lease operating expenses (1)	$6.65	$6.49	$0.16	$6.92	$6.32	$0.60
Marketing, transportation and gathering expenses	3.93	1.06	2.87	2.60	1.31	1.29
Production taxes	7.79	7.41	0.38	7.97	7.81	0.16
Depreciation, depletion and amortization	24.33	23.87	0.46	24.37	24.04	0.33
General and administrative expenses	6.07	7.31	(1.24)	5.58	7.45	(1.87)

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

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

Lease operating expenses. Lease operating expenses increased $6.2 million to $18.3 million for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our well completions. Additionally, the formation of OMS in the first quarter of 2013 resulted in income related to midstream activity being included in well services and midstream revenues, rather than as a reduction to lease operating expenses. Lease operating expenses increased from $6.49 per Boe for the three months ended June 30, 2012 to $6.65 per Boe for the three months ended June 30, 2013, and $0.75 per Boe of this increase was associated with the formation of OMS.

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 $5.4 million increase for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 was attributable to a $5.2 million increase from OWS' well completion activity and related product sales, and a $0.2 million increase related to midstream services operating expenses. There were no midstream services operating expenses during the second quarter of 2012 because OMS did not commence activity until the first quarter of 2013.

Marketing, transportation and gathering expenses. The $8.8 million increase for the three months ended June 30, 2013 compared to the three months ended June 30, 2012 was primarily attributable to a $5.8 million bulk oil purchase made by OPM coupled with higher operated volumes flowing through third-party gathering pipelines during the three months ended June 30,

2013. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the three months ended June 30, 2013 and 2012 were 9.1% and 9.5%, respectively, as a percentage of oil and natural gas sales. The second quarter 2013 production tax rate was lower than the second quarter 2012 production tax rate primarily due to the increased weighting of oil revenues on certain new wells in Montana that are subject to lower incentivized production tax rates.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $22.6 million to $66.8 million for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. This increase in DD&A expense for the three months ended June 30, 2013 was primarily a result of our production increases from our wells completed during the twelve months ended June 30, 2013. The DD&A rate for the three months ended June 30, 2013 was $24.33 per Boe compared to $23.87 per Boe for the three months ended June 30, 2012.

Impairment of oil and gas properties. During the three months ended June 30, 2013 and 2012, we recorded non-cash impairment charges of $0.2 million and $2.2 million, respectively, for expiring leases and periodic assessments of unproved properties. No impairment charges of proved oil and gas properties were recorded for the three months ended June 30, 2013 or 2012.

General and administrative ("G&A") expenses. Our G&A expenses increased $3.1 million for the three months ended June 30, 2013 from $13.5 million for the three months ended June 30, 2012. Of this increase, approximately $3.1 million related to increased employee compensation expense due to our organizational growth and $0.8 million was due to increased amortization of our restricted stock awards and performance share units quarter over quarter. As of June 30, 2013, we had 322 full-time employees compared to 223 full-time employees as of June 30, 2012. There was an offsetting decrease quarter over quarter of $0.6 million related to the formation of OMS.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net gain of $1.2 million for the three months ended June 30, 2013 and a cash settlement net loss of $1.2 million for the three months ended June 30, 2012. In addition, as a result of forward oil price changes, we recognized an $11.3 million and a $75.8 million non-cash unrealized mark-to-market net derivative gain during the three months ended June 30, 2013 and 2012, respectively.

Interest expense. Interest expense increased $7.3 million to $21.4 million for the three months ended June 30, 2013 compared to the three months ended June 30, 2012. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in July 2012 at an interest rate of 6.875%. There were no borrowings under our revolving credit facility during the three months ended June 30, 2013 or 2012. Interest capitalized during the three months ended June 30, 2013 and 2012 was $1.1 million and $0.8 million, respectively.

Income taxes. Income tax expense for the three months ended June 30, 2013 and 2012 was recorded at 36.0% and 37.4% 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, 2013 compared to six months ended June 30, 2012

Lease operating expenses. Lease operating expenses increased $15.9 million to $37.8 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our well completions. Additionally, the formation of OMS in the first quarter of 2013 resulted in income related to midstream activity being included in well services and midstream revenues, rather than as a reduction to lease operating expenses. Lease operating expenses increased from $6.32 per Boe for the six months ended June 30, 2012 to $6.92 per Boe for the six months ended June 30, 2013, and $0.68 per Boe of this increase was associated with the formation of OMS.

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 $7.9 million increase for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 was attributable to a $7.4 million increase from OWS' well completion activity and related product sales, and a $0.5 million increase related to midstream services operating expenses. There were no midstream services operating expenses during the first half of 2012 because OMS did not commence activity until the first quarter of 2013.

Marketing, transportation and gathering expenses. The $9.6 million increase for the six months ended June 30, 2013 compared to the six months ended June 30, 2012 was primarily attributable to a $5.2 million increase related to higher operated volumes flowing through third-party gathering pipelines and a $4.4 million increase in bulk oil purchases made by OPM. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the six months ended June 30, 2013 and 2012 were 9.1% and 9.6%, respectively, as a percentage of oil and natural gas sales. The production tax rate for the six months ended June 30, 2013 was lower than the production tax rate for the six months ended June 30, 2012 primarily due to the increased weighting of oil revenues on certain new wells in Montana that are subject to lower incentivized production tax rates.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $50.0 million to $133.1 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. This increase in DD&A expense for the six months ended June 30, 2013 was primarily a result of our production increases from our wells completed during the twelve months ended June 30, 2013. The DD&A rate for the six months ended June 30, 2013 was $24.37 per Boe compared to $24.04 per Boe for the six months ended June 30, 2012.

Impairment of oil and gas properties. During the six months ended June 30, 2013 and 2012, we recorded non-cash impairment charges of $0.7 million and $2.6 million, respectively, for expiring leases and periodic assessments of unproved properties. No impairment charges of proved oil and gas properties were recorded for the six months ended June 30, 2013 or 2012.

General and administrative ("G&A") expenses. Our G&A expenses increased $4.8 million for the six months ended June 30, 2013 from $25.7 million for the six months ended June 30, 2012. Of this increase, approximately $5.9 million related to increased employee compensation expenses due to our organizational growth and $1.4 million was due to increased amortization of our restricted stock awards and performance share units period over period. As of June 30, 2013, we had 322 full-time employees compared to 223 full-time employees as of June 30, 2012. There was an offsetting decrease of $1.2 million related to OWS and $0.6 million related to the formation of OMS during the six months ended June 30, 2013.

Derivative instruments. As a result of our derivative activities, we incurred a cash settlement net gain of $2.9 million for the six months ended June 30, 2013 and a cash settlement net loss of $2.5 million for the six months ended June 30, 2012. In addition, as a result of forward oil price changes, we recognized a $5.0 million non-cash unrealized mark-to-market net derivative loss during the six months ended June 30, 2013 and a $58.5 million non-cash unrealized mark-to-market net derivative gain during the six months ended June 30, 2012.

Interest expense. Interest expense increased $14.6 million to $42.6 million for the six months ended June 30, 2013 compared to the six months ended June 30, 2012. The increase was primarily the result of interest expense incurred on our senior unsecured notes issued in July 2012 at an interest rate of 6.875%. There were no borrowings under our revolving credit facility during the six months ended June 30, 2013 and 2012, respectively. Interest capitalized during the six months ended June 30, 2013 and 2012 was $1.9 million and $1.6 million, respectively.

Income taxes. Income tax expense for the six months ended June 30, 2013 and 2012 was recorded at 36.7% and 37.4% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report are proceeds from our senior unsecured notes, cash flows from operations and availability under our revolving credit facility. Our primary use of capital has been for the development and acquisition of oil and natural gas properties. We continually monitor potential capital sources, including 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.

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

	Six Months Ended June 30, 2013	2012
	(In thousands)	
Net cash provided by operating activities	$357,807	$171,860
Net cash used in investing activities	(406,291)	(401,894)
Net cash used in financing activities	(3,362)	(1,952)
Decrease in cash and cash equivalents	$(51,846)	$(231,986)

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 $357.8 million and $171.9 million for the six months ended June 30, 2013 and 2012, respectively. The increase in cash flows provided by operating activities for the period ended June 30, 2013 as compared to 2012 was primarily the result of our 59% increase in oil and natural gas production. In addition, 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 $406.3 million and $401.9 million during the six months ended June 30, 2013 and 2012, respectively, and was primarily attributable to capital expenditures for drilling and development costs. Our capital expenditures for drilling, development, acquisition, OWS and non-E&P costs are summarized in the following table:

	Six Months Ended June 30, 2013 (In thousands)
Project Area:	
West Williston	$222,309
East Nesson	175,005
Sanish	25,520
Total E&P capital expenditures (1)	422,834
OWS	2,861
Non-E&P capital expenditures (2)	3,643
Total capital expenditures (3)	$429,338

(1) Total E&P capital expenditures include $6.0 million for OMS, primarily related to salt water disposal systems.

(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 accrued liabilities for capital expenditures, while the amounts presented in the statement of cash flows are presented on a cash basis.

Our total 2013 capital expenditure budget is $1,020 million, which consists of:

- $897 million of drilling and completion capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS);

- $43 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems;
- $25 million for maintaining and expanding our leasehold position;

- $10 million for micro-seismic work, purchasing seismic data and other test work;
- $21 million for facilities and other miscellaneous E&P capital expenditures;
- $14 million for OWS; and
- $10 million for other non-E&P capital, including items such as administrative capital and capitalized interest.

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

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

Cash flows used in financing activities

Net cash used in financing activities was $3.4 million and $2.0 million for the six months ended June 30, 2013 and 2012, respectively. 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 senior secured revolving line of credit entered into on April 5, 2013. For the six months ended June 30, 2012, cash used in financing activities was primarily attributable to purchases of treasury stock for shares withheld by us equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards.

Senior unsecured notes. On February 2, 2011, we issued $400 million of 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”). Interest is payable on the 2019 Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The 2019 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2019 Notes resulted in net proceeds to us of approximately $390 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

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

On November 10, 2011, we issued $400 million of 6.5% senior unsecured notes due November 1, 2021 (the “2021 Notes”). Interest is payable on the 2021 Notes semi-annually in arrears on each May 1 and November 1, commencing May 1, 2012. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2021 Notes resulted in net proceeds to us of approximately $393 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

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

On July 2, 2012, we issued $400 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes”). Interest is payable on the 2023 Notes semi-annually in arrears on each January 15 and July 15, commencing January 15, 2013. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2023 Notes resulted in net proceeds to us of approximately $392 million, which we are using to fund our exploration, development and acquisition program and for general corporate purposes.

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

The indentures governing our 2019 Notes, 2021 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. In connection with entry into the Second Amended Credit Facility, the semi-annual redetermination of our borrowing base was also completed on April 5, 2013, which resulted in an increase to the borrowing base of the Second Amended Credit Facility from $750 million to $1.25 billion. However, we elected to limit the aggregate commitment of the lenders under the Second Amended Credit Facility (the “Lenders”) to $900 million. We may increase our aggregate commitment to the full $1.25 billion borrowing base by increasing the commitment of one or more lenders. In addition, under the Second Amended Credit Facility, the overall credit facility increased from $1 billion to $2.5 billion, and we added four new lenders to the bank group.

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

As of June 30, 2013, we had no borrowings and $2.2 million outstanding letters of credit under our Second Amended Credit Facility, resulting in an unused borrowing base capacity of $897.8 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, 2013, we were in compliance with the financial covenants of our Second Amended Credit Facility.

Fair Value of Financial Instruments

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

Disclosures About Market Risk” below.

Critical Accounting Policies and Estimates

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

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Off-Balance Sheet Arrangements

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

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Item 3. — Quantitative and Qualitative Disclosures About Market Risk

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

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

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

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

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

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

Settlement Period	Derivative Instrument	Total Notional Amount of Oil (Barrels)	Weighted Average Prices ($/Barrel) Swap	Sub-Floor	Floor	Ceiling	Fair Value Asset (Liability) (In thousands)
2013	Two-way collars	1,006,500			$86.82	$97.75	$(985)
2013	Three-way collars	1,121,790		$65.92	92.45	111.45	1,898
2013	Put spreads	906,210		70.93	91.09		1,364
2013	Swaps	1,464,000	$95.40				(255)
2014	Two-way collars	504,500			88.92	95.86	682
2014	Three-way collars	2,695,030		70.33	90.79	106.21	9,870
2014	Put spreads	150,970		71.03	91.03		576
2014	Swaps	1,083,000	93.04				2,290
2014	Swaps with sub-floors	1,336,000	92.03	70.00			318
2015	Two-way collars	31,000			90.00	94.90	137
2015	Three-way collars	232,500		70.67	90.67	105.81	1,114
2015	Swaps	77,500	92.34				363
2015	Swaps with sub-floors	124,000	92.03	70.00			244

$17,616

Interest rate risk. We had (i) $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum, (ii) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum and (iii) $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum outstanding at June 30, 2013. During the first six months of 2013, we had no indebtedness outstanding under our Second Amended Credit Facility. We do not currently, but may in the future, utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to debt issued under our Second Amended Credit Facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

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

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

We may, from time to time, purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. Our investment policy requires that our counterparties have minimum credit ratings thresholds and provides maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers being unable to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If a commercial paper issuer is unable to return investment proceeds to us at the maturity date, it could take a significant amount of time to recover all or a portion of the assets originally invested. Our commercial paper balance was $15.0 million at June 30, 2013.

Most of the counterparties on our derivative instruments currently in place are lenders under our Second Amended Credit Facility with investment grade ratings. We are likely to enter into future derivative instruments with these or other lenders under our Second Amended Credit Facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $17.6 million at June 30, 2013.

Item 4. — Controls and Procedures

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

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

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PART II — OTHER INFORMATION
Item 1. — Legal Proceedings
See Part I, Item 1, Note 13 to our unaudited condensed consolidated financial statements entitled “Commitments and Contingencies,” which is incorporated in this item by reference.
Item 1A. — Risk Factors
Our business faces many risks. Any of the risks discussed elsewhere in this Form 10-Q and our other SEC filings could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.
There have been no material changes in our risk factors from those described in our 2012 Annual Report. For a discussion of our potential risks and uncertainties, see the information in Item 1A. “Risk Factors” in our 2012 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, 2013:

Period	Total Number of Shares Exchanged (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
April 1 - April 30, 2013	1,497	$36.97	—	—
May 1 - May 31, 2013	1,766	32.85	—	—
June 1 - June 30, 2013	2,512	37.27	—	—
Total	5,775	$35.84	—	—

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

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Item 6. — Exhibits

Exhibit No.	Description of Exhibit
4.1(a)	Third Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of June 18, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee.
4.2(a)	Third Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of June 18, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee.
10.1	Second Amended and Restated Credit Agreement, dated as of April 5, 2013, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on April 9, 2013, and incorporated herein by reference).
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS (a)	XBRL Instance Document.
101.SCH (a)	XBRL Schema Document.
101.CAL (a)	XBRL Calculation Linkbase Document.
101.DEF (a)	XBRL Definition Linkbase Document.
101.LAB (a)	XBRL Labels Linkbase Document.
101.PRE (a)	XBRL Presentation Linkbase Document.

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

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SIGNATURES

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

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

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(b) Furnished herewith.