Oasis Petroleum Inc.
Form 10-Q
May 10, 2016
Table of Contents

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

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2016
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-34776

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes 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 May 4, 2016: 180,449,655 shares.

Table of Contents

OASIS PETROLEUM INC.
FORM 10-Q
FOR THE QUARTER ENDED MARCH 31, 2016
TABLE OF CONTENTS

Table of Contents

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

	March 31, 2016	December 31, 2015
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 19,397	$ 9,730
Accounts receivable — oil and gas revenues	92,684	96,495
Accounts receivable — joint interest and other	104,512	100,914
Inventory	10,723	11,072
Prepaid expenses	7,411	7,328
Derivative instruments	91,590	139,697
Other current assets	46	50
Total current assets	326,363	365,286
Property, plant and equipment		
Oil and gas properties (successful efforts method)	6,327,027	6,284,401
Other property and equipment	477,343	443,265
Less: accumulated depreciation, depletion, amortization and impairment	(1,627,201)	(1,509,424)
Total property, plant and equipment, net	5,177,169	5,218,242
Assets held for sale	25,845	26,728
Derivative instruments	7,521	15,776
Other assets	23,370	23,343
Total assets	$ 5,560,268	$ 5,649,375
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 10,101	$ 9,983
Revenues and production taxes payable	115,412	132,356
Accrued liabilities	126,765	167,669
Accrued interest payable	24,277	49,413
Derivative instruments	1,018	—
Advances from joint interest partners	4,390	4,647
Other current liabilities	500	6,500
Total current liabilities	282,463	370,568
Long-term debt	2,201,938	2,302,584
Deferred income taxes	580,526	608,155
Asset retirement obligations	36,088	35,338
Liabilities held for sale	10,155	10,228
Derivative instruments	1,558	—
Other liabilities	3,091	3,160
Total liabilities	3,115,819	3,330,033
Commitments and contingencies (Note 15)		
Stockholders' equity		
Common stock, $0.01 par value: 300,000,000 shares authorized; 181,298,001 shares issued and 180,582,855 shares outstanding at March 31, 2016 and 139,583,990 shares issued and 139,076,064 shares outstanding at December 31, 2015	1,774	1,376

Treasury stock, at cost: 715,146 and 507,926 shares at March 31, 2016 and December 31, 2015, respectively	(14,652)	(13,620)
Additional paid-in capital	1,687,261	1,497,065
Retained earnings	770,066	834,521
Total stockholders’ equity	2,444,449	2,319,342
Total liabilities and stockholders’ equity	$ 5,560,268	$ 5,649,375

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

Table of Contents

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

	Three Months Ended March 31,	
	2016	2015
	(In thousands, except per share data)	
Revenues		
Oil and gas revenues	$ 117,315	$ 173,859
Well services and midstream revenues	12,968	6,528
Total revenues	130,283	180,387
Operating expenses		
Lease operating expenses	31,064	39,125
Well services and midstream operating expenses	4,389	1,952
Marketing, transportation and gathering expenses	8,552	7,278
Production taxes	10,753	16,621
Depreciation, depletion and amortization	122,449	118,478
Exploration expenses	363	843
Rig termination	—	1,080
Impairment	3,562	5,321
General and administrative expenses	24,366	23,324
Total operating expenses	205,498	214,022
Operating loss	(75,215)	(33,635)
Other income (expense)		
Net gain on derivative instruments	14,375	47,072
Interest expense, net of capitalized interest	(38,739)	(38,784)
Gain on extinguishment of debt	7,016	—
Other income (expense)	479	(70)
Total other income (expense)	(16,869)	8,218
Loss before income taxes	(92,084)	(25,417)
Income tax benefit	27,629	7,376
Net loss	$ (64,455)	$ (18,041)
Loss per share:		
Basic (Note 13)	$ (0.40)	$ (0.17)
Diluted (Note 13)	(0.40)	(0.17)
Weighted average shares outstanding:		
Basic (Note 13)	162,922	109,303
Diluted (Note 13)	162,922	109,303

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

Table of Contents

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
	(In thousands)						
Balance as of December 31, 2015	139,076	$ 1,376	508	$ (13,620)	$ 1,497,065	$ 834,521	$ 2,319,342
Issuance of common stock	39,100	391	—	—	182,773	—	183,164
Stock-based compensation	2,614	—	—		7,430	—	7,430
Vesting of restricted shares	—	7	—	—	(7)	—	—
Treasury stock – tax withholdings	(207)	—	207	(1,032)	—	—	(1,032)
Net loss	—	—	—	—	—	(64,455)	(64,455)
Balance as of March 31, 2016	180,583	$ 1,774	715	$ (14,652)	$ 1,687,261	$ 770,066	$ 2,444,449

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

Table of Contents

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

	Three Months Ended March 31, 2016	2015
	(In thousands)	
Cash flows from operating activities:		
Net loss	$(64,455)	$(18,041)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	122,449	118,478
Gain on extinguishment of debt	(7,016)	—
Impairment	3,562	5,321
Deferred income taxes	(27,629)	(7,376)
Derivative instruments	(14,375)	(47,072)
Stock-based compensation expenses	6,730	7,606
Deferred financing costs amortization and other	5,066	1,655
Working capital and other changes:		
Change in accounts receivable	(995)	63,313
Change in inventory	349	(602)
Change in prepaid expenses	241	1,892
Change in other current assets	4	5,539
Change in other assets	77	—
Change in accounts payable, interest payable and accrued liabilities	(64,056)	(42,341)
Change in other current liabilities	(6,000)	—
Change in other liabilities	(3)	(11)
Net cash provided by (used in) operating activities	(46,051)	88,361
Cash flows from investing activities:		
Capital expenditures	(103,411)	(359,113)
Derivative settlements	73,313	109,259
Advances from joint interest partners	(257)	(828)
Net cash used in investing activities	(30,355)	(250,682)
Cash flows from financing activities:		
Repurchase of senior unsecured notes	(22,308)	—
Proceeds from revolving credit facility	214,000	145,000
Principal payments on revolving credit facility	(287,000)	(480,000)
Deferred financing costs	(751)	—
Proceeds from sale of common stock	183,164	463,218
Purchases of treasury stock	(1,032)	(1,520)
Net cash provided by financing activities	86,073	126,698
Increase (decrease) in cash and cash equivalents	9,667	(35,623)
Cash and cash equivalents:		
Beginning of period	9,730	45,811
End of period	$19,397	$10,188
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$(19,230)	$(90,189)
Change in asset retirement obligations	1,212	1,413

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

4

Table of Contents

OASIS PETROLEUM INC.
Notes to Condensed Consolidated Financial Statements (Unaudited)
1. Organization and Operations of the Company
Oasis Petroleum Inc. (together with its consolidated subsidiaries, “Oasis” or the “Company”) was originally formed in 2007 and was incorporated pursuant to the laws of the State of Delaware in 2010. The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the North Dakota and Montana regions of the Williston Basin. Oasis Petroleum North America LLC (“OPNA”) conducts the Company’s exploration and production activities and owns its proved and unproved oil and natural gas properties. The Company also operates a well services business through Oasis Well Services LLC (“OWS”) and a midstream services business through Oasis Midstream Services LLC (“OMS”), both of which are separate reportable business segments that are complementary to its primary development and production activities.
2. Summary of Significant Accounting Policies
Basis of Presentation
The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis and its wholly-owned subsidiaries. All significant intercompany transactions have been eliminated in consolidation. The accompanying condensed consolidated financial statements of the Company have not been audited by the Company’s independent registered public accounting firm, except that the Condensed Consolidated Balance Sheet at December 31, 2015 is derived from audited financial statements. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for the fair presentation, have been included. Management has made certain estimates and assumptions that affect reported amounts in the condensed consolidated financial statements and disclosures of contingencies. Actual results may differ from those estimates. The results for interim periods are not necessarily indicative of annual results.
These interim financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (“SEC”) regarding interim financial reporting. Certain disclosures have been condensed or omitted from these financial statements. Accordingly, they do not include all of the information and notes required by accounting principles generally accepted in the United States of America (“GAAP”) for complete consolidated financial statements and should be read in conjunction with the Company’s audited consolidated financial statements and notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2015 (“2015 Annual Report”).
Risks and Uncertainties
As an oil and natural gas producer, the Company’s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, political and regulatory developments and competition from other energy sources. The energy markets have historically been very volatile, and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. Oil and natural gas prices have declined significantly since mid-2014. As a result of sustained lower commodity prices, the Company decreased its 2016 capital expenditures as compared to 2015 and continues to concentrate its drilling activities in certain areas that are the most economic in the Williston Basin. An extended period of low prices for oil and, to a lesser extent, natural gas could have a material adverse effect on the Company’s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.
Significant Accounting Policies
There have been no material changes to the Company’s critical accounting policies and estimates from those disclosed in the 2015 Annual Report.
Recent Accounting Pronouncements
Revenue recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Deferral of the Effective Date (“ASU 2015-14”). ASU

2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. In March 2016, the FASB issued Accounting Standards Update No. 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), which clarifies the implementation guidance on principal versus agent considerations on such matters. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Table of Contents

Going concern. In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 codifies in GAAP management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual reporting period ending after December 15, 2016 and for annual periods and interim periods thereafter. The adoption of this guidance will not impact the Company's financial position, cash flows or results of operations, but could result in additional disclosures.

Inventory. In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"). ASU 2015-11 changes the inventory measurement principle from lower of cost or market to lower of cost and net realizable value for entities using the first-in, first-out (FIFO) or average cost methods. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Financial instruments. In January 2016, the FASB issued Accounting Standards Update No. 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"), which requires that most equity instruments be measured at fair value with subsequent changes in fair value recognized in net income. ASU 2016-01 also impacts financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. ASU 2016-01 does not apply to equity method investments or investments in consolidated subsidiaries. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Leases. In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"), which requires a lessee to recognize lease payment obligations and a corresponding right-of-use asset to be measured at fair value on the balance sheet. ASU 2016-02 also requires certain qualitative and quantitative disclosures about the amount, timing and uncertainty of cash flows arising from leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Embedded derivatives. In March 2016, the FASB issued Accounting Standards Update No. 2016-06, Contingent Put and Call Options in Debt Instruments ("ASU 2016-06"), which clarifies what steps are required when assessing whether the economic characteristics and risks of call (put) options are clearly and closely related to the economic characteristics and risks of their debt hosts, which is one of the criteria for bifurcating an embedded derivative. ASU 2016-06 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

Stock-based compensation. In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"), which updates several aspects of the accounting for share-based payment transactions, including recognition of excess tax benefits and deficiencies, the classification of those excess tax benefits on the statement of cash flows, an accounting policy election for forfeitures, the amount an employer can withhold to cover income taxes and still qualify for equity classification and the classification of those taxes paid on the statement of cash flows. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. The Company is currently evaluating the effect that adopting this guidance will have on its financial position, cash flows and results of operations.

3. Inventory

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

	March 31, 2016	December 31, 2015

	(In thousands)	
Equipment and materials	$4,729	$ 4,920
Crude oil inventory	5,994	6,152
Total inventory	$10,723	$ 11,072

4. Fair Value Measurements

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

6

Table of Contents

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

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

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

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

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

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

Financial Assets and Liabilities

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

The following tables set forth by level within the fair value hierarchy the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis:

	At fair value as of March 31, 2016			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$54	$—	$ —	$54
Commodity derivative instruments (see Note 5)	—	99,111	—	99,111
Total assets	$54	$99,111	$ —	$99,165
Liabilities:				
Commodity derivative instruments (see Note 5)	$—	$2,576	$ —	$2,576
Total liabilities	$—	$2,576	$ —	$2,576

	At fair value as of December 31, 2015			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$742	$—	$ —	$742
Commodity derivative instruments (see Note 5)	—	155,473	—	155,473

Total assets	$742	$155,473	$ —	$156,215

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 March 31, 2016 and December 31, 2015. The Company's money market funds represent cash equivalents backed by the assets of high-quality major banks and financial institutions. The Company identifies the money market funds as Level 1 instruments because the money market funds have daily liquidity, quoted prices for the underlying investments can be obtained, and there are active markets for the underlying investments.

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include oil collars and swaps. 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 calculates the credit adjustment for derivatives in a net asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a net liability position is based on the Company's market credit spread. Based on these calculations, the Company recorded an adjustment to reduce the fair value of its net derivative asset by $0.1 million and $0.3 million at March 31, 2016 and December 31, 2015, respectively.

There were no transfers between fair value levels during the three months ended March 31, 2016 and 2015.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At March 31, 2016, the Company's cash equivalents were all Level 1 assets.

The carrying amount of the Company's long-term debt reported in the Condensed Consolidated Balance Sheet at March 31, 2016 was $2,201.9 million, which included $2,170.2 million of senior unsecured notes, $65.0 million of borrowings under the revolving credit facility and a $33.3 million reduction for deferred financing costs on the senior unsecured notes (see Note 8 – Long-Term Debt). The fair value of the Company's senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, was $1,632.7 million at March 31, 2016.

Non-Financial Assets and Liabilities

Asset retirement obligations. The carrying amount of ARO in the Company's Condensed Consolidated Balance Sheet at March 31, 2016 was $37.0 million (see Note 9 – Asset Retirement Obligations). The Company determines its 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 the timing and existence of a liability, as well as what constitutes adequate restoration when considering current regulatory requirements. 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 proved oil and natural gas properties and then compares such undiscounted future cash flows to the carrying amount of the proved 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 proved oil and natural gas properties to the 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.
As of March 31, 2016, the Company had certain proved oil and natural gas properties and other midstream properties held for sale (see Note 7 — Assets Held for Sale). For the three months ended March 31, 2016, the Company recorded an impairment loss of $3.6 million, of which $2.4 million was included in earnings in its midstream services segment and $1.1

Table of Contents

million was included in earnings in its exploration and production segment, to adjust the current carrying value of these assets, net of the associated ARO liabilities, to their estimated fair value of $15.7 million. For the year ended December 31, 2015, the Company recorded an impairment loss of $9.4 million to adjust its net assets held for sale to their estimated fair value. The fair value was determined based on the expected sales price, less costs to sell. No other impairment charges on proved oil and natural gas properties were recorded for the three months ended March 31, 2016. No impairment charges on proved oil and natural gas properties were recorded for the three months ended March 31, 2015.

In addition, as a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and natural gas properties of $5.3 million for the three months ended March 31, 2015. For the three months ended March 31, 2016, the Company did not record similar impairment charges as current expiring leases were already expensed as a result of the Company’s periodic assessments of unproved properties in prior periods.

5. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of March 31, 2016, the Company utilized two-way costless collar options and swaps 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 swap is a sold call and a purchased put established at the same price (both ceiling and floor).

All derivative instruments are recorded on the Company’s Condensed Consolidated Balance Sheet as either assets or liabilities measured at fair value (see Note 4 – Fair Value Measurements). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value are recognized in the other income (expense) section of the Company’s Condensed Consolidated Statement of Operations as a net gain or loss on derivative instruments. The Company’s cash flow is only impacted when the actual settlements under the derivative contracts result in making a payment to or receiving a payment from the counterparty. These cash settlements represent the cumulative gains and losses on the Company’s derivative instruments and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled. Cash settlements are reflected as investing activities in the Company’s Condensed Consolidated Statement of Cash Flows.

As of March 31, 2016, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the average NYMEX West Texas Intermediate crude oil index price (“WTI”):

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices			Fair Value
			Swap	Floor	Ceiling	
		(Barrels)	($/Barrel)			(In thousands)
2016	Swaps	8,707,000	$50.60			$ 82,960
2017	Swaps	3,967,000	$48.01			13,906
2017	Two-way collars	668,000		$40.00	$47.58	(638)
2018	Swaps	279,000	$47.61			433
2018	Two-way collars	62,000		$40.00	$47.58	(126)
						$ 96,535

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

Commodity	Balance Sheet Location	Fair Value Asset (Liability)	
		March 31, 2016	December 31, 2015
		(In thousands)	
Crude oil	Derivative instruments — current assets	$91,590	$139,697

Crude oil	Derivative instruments — non-current assets	7,521	15,776
Crude oil	Derivative instruments — current liabilities	(1,018)	—
Crude oil	Derivative instruments — non-current liabilities	(1,558)	—
Total derivative instruments		$96,535	$155,473

9

Table of Contents

The following table summarizes the location and amounts of gains and losses from the Company’s commodity derivative instruments recorded in the Company’s Condensed Consolidated Statement of Operations for the periods presented:

Statement of Operations Location	Three Months Ended March 31, 2016	2015
	(In thousands)	
Net gain on derivative instruments	$14,375	$47,072

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

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

Offsetting of Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
	(In thousands)		
As of March 31, 2016	$ 108,205	$ (9,094)	$ 99,111
As of December 31, 2015	155,473	—	155,473

Offsetting of Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet
	(In thousands)		
As of March 31, 2016	$ 11,670	$ (9,094)	$ 2,576
As of December 31, 2015	—	—	—

6. Property, Plant and Equipment

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

	March 31, 2016	December 31, 2015
	(In thousands)	
Proved oil and gas properties[(1)]	$5,698,259	$5,655,759
Less: accumulated depreciation, depletion, amortization and impairment	(1,539,515)	(1,428,427)
Proved oil and gas properties, net	4,158,744	4,227,332
Unproved oil and gas properties	628,768	628,642
Other property and equipment	477,343	443,265
Less: accumulated depreciation	(87,686)	(80,997)
Other property and equipment, net	389,657	362,268
Total property, plant and equipment, net	$5,177,169	$5,218,242

(1) Included in the Company’s proved oil and gas properties are estimates of future asset retirement costs of $31.1 million and $30.7 million at March 31, 2016 and December 31, 2015, respectively.

7. Assets Held for Sale

Net assets held for sale represent the assets that were expected to be sold, net of liabilities, which were expected to be assumed by the purchaser. As of March 31, 2016 and December 31, 2015, certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations were held for sale. These assets primarily consist of oil and gas properties in the Company’s exploration and production segment and include certain other property and equipment in the Company’s midstream segment. For the three months ended March 31, 2016 and the year ended December 31, 2015, the Company recorded losses of $3.6

Table of Contents

million and $9.4 million, respectively, which were included in impairment on the Company's Condensed Consolidated Statement of Operations, to adjust the carrying value of these assets to their estimated fair value, determined based on the expected sales price, less costs to sell. The Company sold these assets on April 1, 2016 (see Note 17 – Subsequent Events). The following table presents balance sheet data related to the assets held for sale:

	March 31, 2016 (In thousands)
Assets:	
Oil and gas properties	$ 121,137
Other property and equipment	34
Less: accumulated depreciation, depletion, amortization and impairment	(95,326)
Total assets	$ 25,845
Liabilities:	
Asset retirement obligation	$ (10,155)
Total liabilities	$ (10,155)
Net assets	$ 15,690

8. Long-Term Debt

As of March 31, 2016 and December 31, 2015, the Company's long-term debt consisted of the following:

	March 31, 2016	December 31, 2015
	(In thousands)	
Senior unsecured notes		
7.25% senior unsecured notes due February 1, 2019	$ 400,000	$ 400,000
6.5% senior unsecured notes due November 1, 2021	399,000	400,000
6.875% senior unsecured notes due March 15, 2022	985,000	1,000,000
6.875% senior unsecured notes due January 15, 2023	386,200	400,000
Less: deferred financing costs related to senior unsecured notes	(33,262)	(35,416)
Senior secured revolving line of credit	65,000	138,000
Total long-term debt	$ 2,201,938	$ 2,302,584

Senior unsecured notes. At March 31, 2016, the Company had $2,170.2 million principal amount of senior unsecured notes outstanding with maturities ranging from February 2019 to January 2023 and coupons ranging from 6.5% to 7.25% (the "Notes"). Interest on the Notes is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by the Company, along with its material subsidiaries (the "Guarantors"), which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions. The indentures governing the Notes contain customary events of default as well as covenants that place restrictions on the Company and certain of its subsidiaries.

Prior to certain dates, the Company has certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption.

Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The Company estimates that the fair value of these redemption options is immaterial at March 31, 2016 and December 31, 2015.

In March 2016, the Company repurchased an aggregate principal amount of $29.8 million of its outstanding Notes, consisting of $1.0 million principal amount of its 6.5% senior unsecured notes due November 2021, $15.0 million principal amount of its 6.875% senior unsecured notes due March 2022 and $13.8 million principal amount of its

6.875% senior unsecured notes due January 2023, for an aggregate cost of $22.3 million, including accrued interest and fees. The Company recognized a pre-tax gain of $7.0 million related to these repurchases, which was net of the $0.5 million write-off of unamortized deferred financing costs, and is reflected in gain on extinguishment of debt in the Company’s Condensed Consolidated Statement of Operations for the three months ended March 31, 2016.

Senior secured revolving line of credit. The Company has a senior secured revolving line of credit of $2,500.0 million as of March 31, 2016 (the "Credit Facility"), which has a maturity date of April 13, 2020. The Credit Facility is restricted to a borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On February 23, 2016, the lenders under the Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2016, resulting in a decrease in the borrowing base and aggregate elected commitment from $1,525.0 million to $1,150.0 million.

As of March 31, 2016, the Company had $45.0 million of LIBOR loans, $20.0 million of ABR loans and $14.2 million of outstanding letters of credit issued under the Credit Facility, resulting in an unused borrowing base committed capacity of $1,070.8 million. The weighted average interest rate on borrowings outstanding under the Credit Facility was 1.9% as of both March 31, 2016 and December 31, 2015. On a quarterly basis, the Company also pays a 0.375% (as of March 31, 2016) 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.

The Company was in compliance with the financial covenants of the Credit Facility as of March 31, 2016.

Deferred financing costs. As of March 31, 2016, the Company had $39.3 million of deferred financing costs related to the Notes and the Credit Facility. Deferred financing costs of $33.3 million related to the Notes are included in long-term debt on the Company's Condensed Consolidated Balance Sheet as of March 31, 2016, and are being amortized over the respective terms of the Notes. Deferred financing costs of $6.0 million related to the Credit Facility are included in other assets on the Company's Condensed Consolidated Balance Sheet as of March 31, 2016, and are being amortized over the term of the Credit Facility. Amortization of deferred financing costs recorded for the three months ended March 31, 2016 and 2015 was $2.1 million and $1.6 million, respectively, and are included in interest expense on the Company's Condensed Consolidated Statement of Operations. For the three months ended March 31, 2016, the Company's interest expense also included a $1.8 million charge for unamortized deferred financing costs related to the Credit Facility, which were written off in proportion to the decrease in the borrowing base. No deferred financing costs were written off during the three months ended March 31, 2015.

9. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the three months ended March 31, 2016:

	(In thousands)
Balance at December 31, 2015	$ 35,812
Liabilities incurred during period	64
Liabilities settled during period	(5)
Accretion expense during period[(1)]	465
Revisions to estimates	571
Liabilities held for sale[(2)]	73
Balance at March 31, 2016	$ 36,980

---

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

(2) Represents the change in ARO related to the properties held for sale during the three months ended March 31, 2016. The total ARO related to the properties held for sale as of March 31, 2016 was $10.2 million (see Note 7 – Assets Held for Sale).

At March 31, 2016, the current portion of the total ARO balance was approximately $0.9 million and is included in accrued liabilities on the Company's Condensed Consolidated Balance Sheet.

10. Income Taxes

The Company's effective tax rate for the three months ended March 31, 2016 and 2015 was 30.0% and 29.0%, respectively. The effective tax rates for both periods were lower than the combined federal statutory rate and the statutory rates for the states in which the Company conducts business due to the impact of permanent differences on the pre-tax loss for each period. The permanent differences were primarily between amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vesting during the three months ended March 31, 2016 and 2015 at stock prices lower than the grant date values.

The Company had deferred tax assets for its federal and state tax net operating losses and other tax carryforwards at March 31, 2016 recorded in deferred income 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. During the three months ended March 31, 2016, the Company recorded a valuation allowance of $0.9 million and $0.6 million for Montana net operating losses and federal charitable contribution carryovers, respectively, based on management's assessment that it is more likely than not that these net deferred tax assets will not be realized prior to their expiration due to current economic conditions and expectations for the future. Management determined that a valuation allowance was not required for its U.S. federal tax net operating loss carryforwards as they are expected to be fully utilized before their expiration. As of March 31, 2016, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

11. Common Stock

On February 2, 2016, the Company completed a public offering of 39,100,000 shares of its common stock (including 5,100,000 shares issued pursuant to the underwriters' option to purchase additional common stock) at an offering price of $4.685 per share. Net proceeds from the offering were $183.2 million, after deducting underwriting discounts and commissions and offering expenses, of which $0.4 million is included in common stock and $182.8 million is included in additional paid-in capital on the Company's Condensed Consolidated Balance Sheet as of March 31, 2016. The Company used the net proceeds for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on July 15, 2014.

12. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock grants is based on the closing sales price of the Company's common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. For the three months ended March 31, 2016, the Company assumed annual forfeiture rates by employee group ranging from 0% to 20.0% based on the Company's forfeiture history for this type of award.

During the three months ended March 31, 2016, employees and non-employee directors of the Company were granted restricted stock awards equal to 2,563,700 shares of common stock with a $4.32 weighted average grant date per share value. Stock-based compensation expense recorded for restricted stock awards for the three months ended March 31, 2016 and 2015 was $5.8 million and $6.8 million, respectively, and is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

Performance share units. The Company has granted performance share units ("PSUs") to officers of the Company under its Amended and Restated 2010 Long Term Incentive Plan. The PSUs are awards of restricted stock units, and each PSU that is earned represents the right to receive one share of the Company's common stock. For the three months ended March 31, 2016, the Company assumed annual forfeiture rates by employee group ranging from 3.3% to 4.6% based on the Company's forfeiture history for the officer employee groups receiving PSUs.

During the three months ended March 31, 2016, officers of the Company were granted 910,000 PSUs with a $3.00 weighted average grant date per share value. Stock-based compensation expense recorded for PSUs for the three months ended March 31, 2016 and 2015 was $0.9 million and $0.8 million, respectively, and is included in general and administrative expenses on the Company's Condensed Consolidated Statement of Operations.

The Company accounted for these PSUs as equity awards pursuant to the FASB's authoritative guidance for share-based payments. 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 periods. Depending on the Company's TSR performance relative to the defined peer group, award recipients will earn between 0% and 200% of the initial PSUs granted. The grant date fair value for each grant of PSUs is recognized on a straight-line basis over a four-year total performance period. 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 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 Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions for the Monte Carlo model are the forecast period, initial value, risk-free interest rate, volatility and correlation coefficients. The risk-free interest rate is the U.S. Treasury bond rate on the date of grant that corresponds to the total performance period. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage change in stock price over a historical period for the Company and each of its peers. The correlation coefficients are measures of the

Table of Contents

strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the PSUs granted during the three months ended March 31, 2016:

Forecast period (years)	4.00
Risk-free interest rate	1.25 %
Oasis stock price volatility	59.38 %

For the PSUs granted during the three months ended March 31, 2016, the Monte Carlo simulation model resulted in approximately 69% of PSUs expected to be earned.

13. Earnings (Loss) Per Share

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

The following is a calculation of the basic and diluted weighted average shares outstanding for the three months ended March 31, 2016 and 2015:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Basic weighted average common shares outstanding	162,922	109,303
Dilution effect of stock awards at end of period[1]	—	—
Diluted weighted average common shares outstanding	162,922	109,303
Anti-dilutive stock-based compensation awards	4,668	3,046

(1) No unvested stock awards were included in computing loss per share for the three months ended March 31, 2016 and 2015 because the effect was anti-dilutive.

14. Business Segment Information

The Company’s exploration and production segment is engaged in the acquisition and development of oil and natural gas properties. Revenues for the exploration and production segment are derived from the sale of oil and natural gas production. The Company’s well services business segment (OWS) performs 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 tool rentals. The Company’s midstream services business segment (OMS) performs salt water gathering and 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 salt water pipeline transport, salt water disposal and fresh water sales. The revenues and expenses related to work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation, and only the revenues and expenses related to non-affiliated working interest owners are included in the Company’s Condensed Consolidated Statement of Operations. These segments represent the Company’s three current operating units, each offering different products and services. The Company’s corporate activities have been allocated to the supported business segments accordingly.

Table of Contents

Management evaluates the performance of the Company’s business segments based on operating income, which is defined as segment operating revenues less operating expenses, including depreciation, depletion and amortization. The following table summarizes financial information for the Company’s business segments for the periods presented:

	Exploration and Production	Well Services	Midstream Services	Eliminations	Consolidated
	(In thousands)				
Three months ended March 31, 2016:					
Revenues from non-affiliates	$117,315	$ 5,985	$6,983	$—	$130,283
Inter-segment revenues	—	24,903	22,835	(47,738)	—
Total revenues	117,315	30,888	29,818	(47,738)	130,283
Operating income (loss)	(88,877)	4,006	15,144	(5,488)	(75,215)
Other income (expense)	(16,887)	5	13	—	(16,869)
Income (loss) before income taxes	$(105,764)	$ 4,011	$15,157	$(5,488)	$(92,084)
Three months ended March 31, 2015:					
Revenues from non-affiliates	$173,859	$ 2,708	$3,820	$—	$180,387
Inter-segment revenues	—	48,197	13,822	(62,019)	—
Total revenues	173,859	50,905	17,642	(62,019)	180,387
Operating income (loss)	(42,247)	9,610	9,308	(10,306)	(33,635)
Other income (expense)	8,239	(2)	(19)	—	8,218
Income (loss) before income taxes	$(34,008)	$ 9,608	$9,289	$(10,306)	$(25,417)
As of March 31, 2016:					
Property, plant and equipment, net	$4,994,366	$ 57,821	$295,913	$(170,931)	$5,177,169
Total assets(1)	5,367,881	62,076	301,242	(170,931)	5,560,268
As of December 31, 2015:					
Property, plant and equipment, net	$5,057,311	$ 61,402	$264,956	$(165,427)	$5,218,242
Total assets(1)	5,478,439	66,952	269,411	(165,427)	5,649,375

(1) As of March 31, 2016, total assets included assets held for sale of $25.8 million in the exploration and production segment and $34,000 in the midstream services segment. As of December 31, 2015, total assets included assets held for sale of $26.7 million in the exploration and production segment (see Note 7 – Assets Held for Sale). For the periods presented, the intercompany receivables (payables) for all segments were reclassified to capital contributions from (distributions to) parent and not included in total assets.

15. Commitments and Contingencies

Included below is a discussion of various future commitments of the Company as of March 31, 2016. The commitments under these arrangements are not recorded in the accompanying Condensed Consolidated Balance Sheet. The amounts disclosed represent undiscounted cash flows on a gross basis, and no inflation elements have been applied.

Lease obligations. The Company’s total rental commitments under leases for office space and other property and equipment as of March 31, 2016 were $24.6 million.

Drilling contracts. As of March 31, 2016, the Company had certain drilling rig contracts with initial terms of one year or greater. In the event of early termination under these contracts, the Company would be obligated to pay approximately $1.8 million as of March 31, 2016 through the end of the primary terms of the contracts.

Volume commitment agreements. As of March 31, 2016, the Company had certain agreements with an aggregate requirement to deliver or transport a minimum quantity of approximately 32.5 MMBbl of crude oil, 23.0 MMBbl of natural gas liquids and 221.8 Bcf of natural gas, prior to any applicable volume credits, within specified timeframes, all of which are ten years or less. The estimable future commitments under these agreements were approximately $446.2 million as of March 31, 2016. The future commitments under certain agreements cannot be estimated as they are based on fixed differentials relative to WTI under the agreements as compared to the differential relative to WTI for the Williston Basin for the production month.

Table of Contents

Purchase agreements. As of March 31, 2016, the Company had certain agreements for the purchase of fresh water with an aggregate future commitment of approximately $42.4 million.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, the Company believes that all such matters are without merit and involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows. When the Company determines that a loss is probable of occurring and is reasonably estimable, the Company accrues an undiscounted liability for such contingencies based on its best estimate using information available at the time. The Company discloses contingencies where an adverse outcome may be material, or in the judgment of management, the matter should otherwise be disclosed.

16. Condensed Consolidating Financial Information

The Notes (see Note 8 – Long-Term Debt) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company’s immaterial wholly-owned subsidiaries do not guarantee the Notes (“Non-Guarantor Subsidiaries”).

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

Condensed Consolidating Balance Sheet

	March 31, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets				
Cash and cash equivalents	$90	$19,307	$—	$19,397
Accounts receivable – oil and gas revenues	—	92,684	—	92,684
Accounts receivable – joint interest and other	—	104,512	—	104,512
Accounts receivable – affiliates	1,348	150,125	(151,473)	—
Inventory	—	10,723	—	10,723
Prepaid expenses	139	7,272	—	7,411
Derivative instruments	—	91,590	—	91,590
Other current assets	—	46	—	46
Total current assets	1,577	476,259	(151,473)	326,363
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	6,327,027	—	6,327,027
Other property and equipment	—	477,343	—	477,343
Less: accumulated depreciation, depletion, amortization and impairment	—	(1,627,201)	—	(1,627,201)
Total property, plant and equipment, net	—	5,177,169	—	5,177,169
Assets held for sale	—	25,845	—	25,845

Investments in and advances to subsidiaries	4,541,136	—	(4,541,136)	—
Derivative instruments	—	7,521	—	7,521
Deferred income taxes	213,270	—	(213,270)	—
Other assets	—	23,370	—	23,370
Total assets	$4,755,983	$5,710,164	$(4,905,879)	$5,560,268
LIABILITIES AND EQUITY				
Current liabilities				
Accounts payable	$—	$10,101	$—	$10,101
Accounts payable – affiliates	150,125	1,348	(151,473)	—
Revenues and production taxes payable	—	115,412	—	115,412
Accrued liabilities	216	126,549	—	126,765
Accrued interest payable	24,255	22	—	24,277
Derivative instruments	—	1,018	—	1,018
Advances from joint partners	—	4,390	—	4,390
Other current liabilities	—	500	—	500
Total current liabilities	174,596	259,340	(151,473)	282,463
Long-term debt	2,136,938	65,000	—	2,201,938
Deferred income taxes	—	793,796	(213,270)	580,526
Asset retirement obligations	—	36,088	—	36,088
Liabilities held for sale	—	10,155	—	10,155
Derivative instruments	—	1,558	—	1,558
Other liabilities	—	3,091	—	3,091
Total liabilities	2,311,534	1,169,028	(364,743)	3,115,819
Stockholders' equity				
Capital contributions from affiliates	—	3,375,186	(3,375,186)	—
Common stock, $0.01 par value: 300,000,000 shares authorized; 181,298,001 shares issued and 180,582,855 shares outstanding	1,774	—	—	1,774
Treasury stock, at cost: 715,146 shares	(14,652)	—	—	(14,652)
Additional paid-in-capital	1,687,261	8,743	(8,743)	1,687,261
Retained earnings	770,066	1,157,207	(1,157,207)	770,066
Total stockholders' equity	2,444,449	4,541,136	(4,541,136)	2,444,449
Total liabilities and stockholders' equity	$4,755,983	$5,710,164	$(4,905,879)	$5,560,268

Condensed Consolidating Balance Sheet

	December 31, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets				
Cash and cash equivalents	$777	$8,953	$—	$9,730
Accounts receivable – oil and gas revenues	—	96,495	—	96,495
Accounts receivable – joint interest and other	15	100,899	—	100,914
Accounts receivable – affiliates	1,248	247,488	(248,736)	—
Inventory	—	11,072	—	11,072
Prepaid expenses	278	7,050	—	7,328
Derivative instruments	—	139,697	—	139,697
Other current assets	—	50	—	50
Total current assets	2,318	611,704	(248,736)	365,286

Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	6,284,401	—	6,284,401
Other property and equipment	—	443,265	—	443,265
Less: accumulated depreciation, depletion, amortization and impairment	—	(1,509,424)	—	(1,509,424)
Total property, plant and equipment, net	—	5,218,242	—	5,218,242
Assets held for sale	—	26,728	—	26,728
Investments in and advances to subsidiaries	4,573,172	—	(4,573,172)	—
Derivative instruments	—	15,776	—	15,776
Deferred income taxes	205,174	—	(205,174)	—
Other assets	100	23,243	—	23,343
Total assets	$4,780,764	$5,895,693	$(5,027,082)	$5,649,375
LIABILITIES AND EQUITY				
Current liabilities				
Accounts payable	$—	$9,983	$—	$9,983
Accounts payable – affiliates	247,488	1,248	(248,736)	—
Revenue and production taxes payable	—	132,356	—	132,356
Accrued liabilities	10	167,659	—	167,669
Accrued interest payable	49,340	73	—	49,413
Advances from joint interest partners	—	4,647	—	4,647
Other current liabilities	—	6,500	—	6,500
Total current liabilities	296,838	322,466	(248,736)	370,568
Long-term debt	2,164,584	138,000	—	2,302,584
Deferred income taxes	—	813,329	(205,174)	608,155
Asset retirement obligations	—	35,338	—	35,338
Liabilities held for sale	—	10,228	—	10,228
Other liabilities	—	3,160	—	3,160
Total liabilities	2,461,422	1,322,521	(453,910)	3,330,033
Stockholders' equity				
Capital contributions from affiliates	—	3,369,895	(3,369,895)	—
Common stock, $0.01 par value: 300,000,000 shares authorized; 139,583,990 shares issued and 139,076,064 shares outstanding	1,376	—	—	1,376
Treasury stock, at cost: 507,926 shares	(13,620)	—	—	(13,620)
Additional paid-in-capital	1,497,065	8,743	(8,743)	1,497,065
Retained earnings	834,521	1,194,534	(1,194,534)	834,521
Total stockholders' equity	2,319,342	4,573,172	(4,573,172)	2,319,342
Total liabilities and stockholders' equity	$4,780,764	$5,895,693	$(5,027,082)	$5,649,375

Condensed Consolidating Statement of Operations

	Three Months Ended March 31, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 117,315	$ —	$ 117,315
Well services and midstream revenues	—	12,968	—	12,968
Total revenues	—	130,283	—	130,283
Operating expenses				
Lease operating expenses	—	31,064	—	31,064

Well services and midstream operating expenses	—	4,389	—	4,389
Marketing, transportation and gathering expenses	—	8,552	—	8,552
Production taxes	—	10,753	—	10,753
Depreciation, depletion and amortization	—	122,449	—	122,449
Exploration expenses	—	363	—	363
Impairment	—	3,562	—	3,562
General and administrative expenses	7,451	16,915	—	24,366
Total operating expenses	7,451	198,047	—	205,498
Operating loss	(7,451)	(67,764)	—	(75,215)
Other income (expense)				
Equity in loss of subsidiaries	(37,327)	—	37,327	—
Net gain on derivative instruments	—	14,375	—	14,375
Interest expense, net of capitalized interest	(34,832)	(3,907)	—	(38,739)
Gain on extinguishment of debt	7,016	—	—	7,016
Other income	43	436	—	479
Total other income (expense)	(65,100)	10,904	37,327	(16,869)
Loss before income taxes	(72,551)	(56,860)	37,327	(92,084)
Income tax benefit	8,096	19,533	—	27,629
Net loss	$(64,455)	$(37,327)	$ 37,327	$ (64,455)

Condensed Consolidating Statement of Operations

	Three Months Ended March 31, 2015			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 173,859	$ —	$ 173,859
Well services and midstream revenues	—	6,528	—	6,528
Total revenues	—	180,387	—	180,387
Operating expenses				
Lease operating expenses	—	39,125	—	39,125
Well services and midstream operating expenses	—	1,952	—	1,952
Marketing, transportation and gathering expenses	—	7,278	—	7,278
Production taxes	—	16,621	—	16,621
Depreciation, depletion and amortization	—	118,478	—	118,478
Exploration expenses	—	843	—	843
Rig termination	—	1,080	—	1,080
Impairment	—	5,321	—	5,321
General and administrative expenses	8,619	14,705	—	23,324
Total operating expenses	8,619	205,403	—	214,022
Operating loss	(8,619)	(25,016)	—	(33,635)
Other income (expense)				
Equity in earnings of subsidiaries	12,619	—	(12,619)	—
Net gain on derivative instruments	—	47,072	—	47,072
Interest expense, net of capitalized interest	(35,221)	(3,563)	—	(38,784)
Other expense	(1)	(69)	—	(70)
Total other income (expense)	(22,603)	43,440	(12,619)	8,218
Income (loss) before income taxes	(31,222)	18,424	(12,619)	(25,417)
Income tax benefit (expense)	13,181	(5,805)	—	7,376
Net income (loss)	$(18,041)	$ 12,619	$ (12,619)	$ (18,041)

Condensed Consolidating Statement of Cash Flows

	Three Months Ended March 31, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Cash flows from operating activities:				
Net loss	$(64,455)	$ (37,327)	$ 37,327	$ (64,455)
Adjustments to reconcile net loss to cash provided by (used in) operating activities:				
Equity in loss of subsidiaries	37,327	—	(37,327)	—
Depreciation, depletion and amortization	—	122,449	—	122,449
Gain on extinguishment of debt	(7,016)	—	—	(7,016)
Impairment	—	3,562	—	3,562
Deferred income taxes	(8,096)	(19,533)	—	(27,629)
Derivative instruments	—	(14,375)	—	(14,375)
Stock-based compensation expenses	6,547	183	—	6,730
Deferred financing costs amortization and other	1,701	3,365	—	5,066
Working capital and other changes:				
Change in accounts receivable	(85)	96,353	(97,263)	(995)
Change in inventory	—	349	—	349
Change in prepaid expenses	139	102	—	241
Change in other current assets	—	4	—	4
Change in other assets	77	—	—	77
Change in accounts payable, interest payable and accrued liabilities	(122,242)	(39,077)	97,263	(64,056)
Change in other current liabilities	—	(6,000)	—	(6,000)
Change in other liabilities	—	(3)	—	(3)
Net cash provided by (used in) operating activities	(156,103)	110,052	—	(46,051)
Cash flows from investing activities:				
Capital expenditures	—	(103,411)	—	(103,411)
Derivative settlements	—	73,313	—	73,313
Advances from joint interest partners	—	(257)	—	(257)
Net cash used in investing activities	—	(30,355)	—	(30,355)
Cash flows from financing activities:				
Repurchase of senior unsecured notes	(22,308)	—	—	(22,308)
Proceeds from revolving credit facility	—	214,000	—	214,000
Principal payments on revolving credit facility	—	(287,000)	—	(287,000)
Deferred financing costs	—	(751)	—	(751)
Proceeds from sale of common stock	183,164	—	—	183,164
Purchases of treasury stock	(1,032)	—	—	(1,032)
Investment in / capital contributions from subsidiaries	(4,408)	4,408	—	—
Net cash provided by (used in) financing activities	155,416	(69,343)	—	86,073
Increase (decrease) in cash and cash equivalents	(687)	10,354	—	9,667
Cash and cash equivalents at beginning of period	777	8,953	—	9,730
Cash and cash equivalents at end of period	$90	$ 19,307	$ —	$ 19,397

Condensed Consolidating Statement of Cash Flows

	Three Months Ended March 31, 2015			
	Parent/	Combined	Intercompany	Consolidated

	Issuer	Guarantor Subsidiaries	Eliminations	
	(In thousands)			
Cash flows from operating activities:				
Net income (loss)	$(18,041)	$ 12,619	$ (12,619)	$ (18,041)
Adjustments to reconcile net income (loss) to cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(12,619)	—	12,619	—
Depreciation, depletion and amortization	—	118,478	—	118,478
Impairment	—	5,321	—	5,321
Deferred income taxes	(13,180)	5,804	—	(7,376)
Derivative instruments	—	(47,072)	—	(47,072)
Stock-based compensation expenses	7,542	64	—	7,606
Deferred financing costs amortization and other	1,119	536	—	1,655
Working capital and other changes:				
Change in accounts receivable	(251)	11,255	52,309	63,313
Change in inventory	—	(602)	—	(602)
Change in prepaid expenses	149	1,743	—	1,892
Change in other current assets	—	5,539	—	5,539
Change in accounts payable, interest payable and accrued liabilities	27,293	(17,325)	(52,309)	(42,341)
Change in other liabilities	—	(11)	—	(11)
Net cash provided by (used in) operating activities	(7,988)	96,349	—	88,361
Cash flows from investing activities:				
Capital expenditures	—	(359,113)	—	(359,113)
Derivative settlements	—	109,259	—	109,259
Advances from joint interest partners	—	(828)	—	(828)
Net cash used in investing activities	—	(250,682)	—	(250,682)
Cash flows from financing activities:				
Proceeds from revolving credit facility	—	145,000	—	145,000
Principal payments on revolving credit facility	—	(480,000)	—	(480,000)
Proceeds from sale of common stock	463,218	—	—	463,218
Purchases of treasury stock	(1,520)	—	—	(1,520)
Investment in / capital contributions from subsidiaries	(453,712)	453,712	—	—
Net cash provided by financing activities	7,986	118,712	—	126,698
Decrease in cash and cash equivalents	(2)	(35,621)	—	(35,623)
Cash and cash equivalents at beginning of period	776	45,035	—	45,811
Cash and cash equivalents at end of period	$774	$ 9,414	$ —	$ 10,188

16

Table of Contents

17. 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.

Divestiture. On April 1, 2016, the Company completed the sale of certain legacy wells that have been producing from conventional reservoirs and other formations in the Williston Basin other than the Bakken or Three Forks formations for cash proceeds of approximately $12.2 million, which includes, and is subject to further, customary post close adjustments, and a $4.0 million 10% secured promissory note due within one year.

Extinguishment of debt. In April 2016, the Company repurchased an additional aggregate principal amount of $46.8 million of its outstanding Notes, consisting of $1.0 million principal amount of its 7.25% senior unsecured notes due February 2019, $1.3 million principal amount of its 6.5% senior unsecured notes due November 2021 and $44.5 million principal amount of its 6.875% senior unsecured notes due March 2022, for an aggregate cost of $34.6 million, including accrued interest and fees.

Derivative instruments. In April and May 2016, the Company entered into new swap and three-way costless collar agreements with a weighted average floor price of $46.23 per barrel for total notional amounts of 153,000 barrels, 1,061,000 barrels and 62,000 barrels, which settle in 2016, 2017 and 2018, respectively, based on WTI. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

Table of Contents

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10-K for the year ended December 31, 2015 ("2015 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 Exchange Act of 1934, as amended (the "Exchange Act"). These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact 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," "project" and similar 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 2015 Annual Report could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about:

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

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

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

Table of Contents

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

Overview

We are an independent exploration and production ("E&P") company focused on the acquisition and development of unconventional oil and natural gas resources primarily in the North Dakota and Montana regions of the Williston Basin. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity is primarily directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. Oasis Petroleum North America LLC ("OPNA") conducts our domestic oil and natural gas E&P activities. We also operate a well services business through Oasis Well Services LLC ("OWS") and a midstream services business through Oasis Midstream Services LLC ("OMS"), both of which are separate reportable business segments that are complementary to our primary development and production activities. The revenues and expenses related to work performed by 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. We built our Williston Basin assets through acquisitions and development activities, which were financed with a combination of capital from private investors, borrowings under our revolving credit facility, cash flows provided by operating activities, proceeds from our senior unsecured notes, proceeds from our public equity offerings, the sale of certain non-core oil and gas properties and cash settlements of derivative contracts. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided an entry into 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. 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, and may fluctuate widely in the future. The current global oversupply of crude oil has caused a sharp decline in oil prices since mid-2014. As a result of sustained low oil prices, we have decreased our planned 2016 capital expenditures as compared to 2015, and we are continuing to concentrate our drilling activities in certain areas that are the most economic in the Williston Basin. Extended 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.

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. 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. 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

Table of Contents

significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of March 31, 2016, we were flowing 84% 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 natural gas reserves. Crude oil produced and sold in the Williston Basin has historically sold at a discount to the NYMEX West Texas Intermediate crude oil index prices (“WTI”) due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to oil production in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. Recent expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the first quarter of 2015, as WTI declined, our price differentials increased as a percentage of WTI but decreased in terms of the dollar per barrel discount to WTI to an average of $7.85 per barrel of oil. In the second quarter of 2015, as WTI improved, our price differentials returned to approximately 10% as a percentage of WTI and continued to decrease in terms of the dollar per barrel discount to WTI to an average of $5.90 per barrel of oil. In the second half of 2015, while WTI fell again, our price differentials strengthened, decreasing to less than $5.00 per barrel of oil and remaining at approximately 10% as a percentage of WTI. In the first quarter of 2016, as WTI continued to fall, our price differentials increased as a percentage of WTI, but remained less than $5.00 per barrel discount to WTI, at an average of $4.85 per barrel of oil. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations.

Forward commodity prices and estimates of future production play a significant role in determining impairment of proved oil and natural gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to monitor our proved oil and natural gas properties for impairment. For the three months ended March 31, 2016, we recorded an impairment loss of $3.6 million to further write down our properties held for sale to their fair value, as determined by the sales price on April 1, 2016, less costs to sell. No other proved impairment charges were recorded during the three months ended March 31, 2016, although the excess of our expected undiscounted future cash flows over the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations has narrowed to $684.0 million as of March 31, 2016, a decrease of approximately 46% as compared to an excess of $1,264.8 million at December 31, 2015. The underlying commodity prices embedded in our expected undiscounted cash flows were determined using NYMEX forward strip prices for five years, escalating 3% per year thereafter. Our expected undiscounted estimated cash flows also included a 3% inflation factor applied to the future operating and development costs after five years. If expected future oil prices decline by 7% as compared to March 31, 2016, holding all other factors constant, the expected undiscounted cash flows may not exceed the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations, and as a result, we may recognize additional proved impairment charges in the future, and such impairment charges could exceed $2,300.0 million assuming a discount rate of 10%.

Changes in commodity prices may significantly impact our estimates of oil and natural gas reserves, which are estimated and reported as of December 31 of each calendar year. Our estimated net proved reserves at December 31, 2015 were determined using unweighted arithmetic average first-day-of-the-month prices for the prior twelve months of $50.16 per barrel for oil and $2.63 per MMBtu for natural gas. The current forward commodity price curve for commodity prices is significantly lower compared to year-end 2015 SEC pricing; therefore, the following sensitivity table is provided to illustrate the estimated impact on our estimated proved reserves, PV-10 and Standardized Measure. In addition to the different price assumptions, the sensitivity case below includes assumed capital and expense reductions we expect to realize at lower commodity prices. The reduction in proved developed reserves is attributable to reaching the economic limit sooner. The reduction in proved undeveloped reserves is a result of well locations no longer meeting our investment criteria as well as reaching the economic limit sooner.

This sensitivity case is only to demonstrate the impact that a lower price and cost environment would have had on estimated proved reserves, PV-10 and Standardized Measure as of December 31, 2015, holding all other factors constant. There is no assurance that these prices or assumed cost savings will actually be achieved. Our estimated net proved reserves, PV-10 and Standardized Measure were determined using prices for oil and natural gas, without giving effect to derivative transactions, which were held constant throughout the life of the properties. The prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Table of Contents

	Actual at December 31, 2015[(1)]		Sensitivity Case[(2)]	
Oil price (per Bbl)	$	50.16	$	39.05
Natural gas price (per MMBtu)	2.63		2.18	
Capital expenditure reduction	n/a		15%	
Operating expense reduction	n/a		16%	
Estimated proved developed reserves (MMBoe)	147.6		144.2	
Estimated proved undeveloped reserves (MMBoe)	70.7		62.8	
Total estimated proved reserves (MMBoe)	$	218.2	$	207.0
PV-10 (in millions)[(3)]	$	2,022.7	$	1,465.3
Present value of future income taxes discounted at 10% (in millions)	108.4		—	
Standardized Measure of discounted future net cash flows (in millions)[(4)]	$	1,914.3	$	1,465.3

(1) The actual reserve estimates at December 31, 2015 were prepared using SEC pricing, calculated as the unweighted arithmetic average first-day-of-the-month prices for the prior twelve months, which was $50.16 per barrel for oil and $2.63 per MMBtu for natural gas for the year ended December 31, 2015.

(2) The sensitivity case prices represent potential SEC pricing based on actual prices for each of the three months ended March 2016 and forward commodity prices as of March 31, 2016 for the remaining months of 2016.

(3) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable financial measure under accounting principles generally accepted in the United States of America (“GAAP”), because it does not include the effect of income taxes on discounted future net cash flows. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas reserves. The oil and gas industry uses PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(4) Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows.

First Quarter 2016 Highlights:

- Average daily production was 50,315 Boe per day during the three months ended March 31, 2016;
-

- We completed and placed on production 15 gross (12.8 net) operated wells in the Williston Basin during the three months ended March 31, 2016;
- For the three months ended March 31, 2016, total capital expenditures were $88.0 million;
- We decreased lease operating expenses to $6.78 per Boe for the three months ended March 31, 2016;
- At March 31, 2016, we had $19.4 million of cash and cash equivalents and had total liquidity of $1,090.2 million, including the availability under our revolving credit facility; and
- Adjusted EBITDA, a non-GAAP financial measure, was $132.9 million for the three months ended March 31, 2016. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income and net cash provided by operating activities, see “Non-GAAP Financial Measures” below.

Results of Operations

Revenues

Our oil and gas revenues are derived from the sale of oil and natural gas production. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices. Our well services and midstream revenues are primarily derived from well completion activity, tool rentals, salt water pipeline transport, salt water disposal and fresh water sales for third-party working interest owners in OPNA’s operated wells. Intercompany revenues for work performed by OWS and OMS for OPNA’s working interests are eliminated in consolidation.

Table of Contents

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

	Three Months Ended March 31,		
	2016	2015	Change
Operating results (in thousands):			
Revenues			
Oil	$111,206	$163,813	$(52,607)
Natural gas	6,109	10,046	(3,937)
Well services	5,985	2,708	3,277
Midstream	6,983	3,820	3,163
Total revenues	$130,283	$180,387	$(50,104)
Production data:			
Oil (MBbls)	3,870	4,022	(152)
Natural gas (MMcf)	4,253	3,107	1,146
Oil equivalents (MBoe)	4,579	4,540	39
Average daily production (Boe per day)	50,315	50,446	(131)
Average sales prices:			
Oil, without derivative settlements (per Bbl)	$28.74	$40.73	$(11.99)
Oil, with derivative settlements (per Bbl)(1)	47.68	67.89	(20.21)
Natural gas (per Mcf)(2)	1.44	3.23	(1.79)

(1) Realized prices include gains or losses on cash settlements for commodity derivatives, which do not qualify for and were not designated as hedging instruments for accounting purposes. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

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

Three months ended March 31, 2016 as compared to three months ended March 31, 2015

Total revenues. Our total revenues decreased $50.1 million, or 28%, to $130.3 million during the three months ended March 31, 2016 as compared to the three months ended March 31, 2015, primarily due to lower realized oil and natural gas sales prices. Our average realized prices for oil and natural gas decreased by 29% and 55%, respectively, during the three months ended March 31, 2016 as compared to the three months ended March 31, 2015.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold decreased by 131 Boe per day to 50,315 Boe per day during the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. The decrease in average daily production sold was primarily a result of the natural decline in production in wells that were producing as of March 31, 2015, offset by our 58.2 total net well completions in the Williston Basin during the twelve months ended March 31, 2016. Average oil sales prices, without derivative settlements, decreased by $11.99 per barrel to an average of $28.74 per barrel, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, decreased by $1.79 per Mcf to an average of $1.44 per Mcf for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. The lower oil and natural gas sales prices decreased revenues by $53.8 million, coupled with lower production amounts sold, which decreased revenues by $2.7 million during the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. Extended low commodity prices could result in a significant decrease in our oil and gas volumes and revenues in the future.

Well services and midstream revenues. In response to the low commodity price environment, we have decreased the pace of our well completions and reduced OWS to one fracturing fleet during the first quarter of 2016. While our well completion activity decreased, our well services revenues increased by $3.3 million to $6.0 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015 primarily due to a $5.5 million increase in well completion revenues as a result of OWS completing OPNA wells with a higher average third-party working interest, offset by a $1.6 million decrease in well completion product sales to third parties as a result of OWS completing all of OPNA's operated wells during the three months ended March 31, 2016. Midstream revenues were $7.0 million for the three months ended March 31, 2016, which was a $3.2 million increase as compared to the three months ended March 31, 2015, primarily due to increased water volumes flowing through our salt water disposal systems and increased fresh water sales.

Table of Contents

Expenses and other income

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

	Three Months Ended March 31,		
	2016	2015	Change
	(In thousands, except per Boe of production)		
Operating expenses:			
Lease operating expenses	$31,064	$39,125	$(8,061)
Well services and midstream operating expenses	4,389	1,952	2,437
Marketing, transportation and gathering expenses	8,552	7,278	1,274
Production taxes	10,753	16,621	(5,868)
Depreciation, depletion and amortization	122,449	118,478	3,971
Exploration expenses	363	843	(480)
Rig termination	—	1,080	(1,080)
Impairment	3,562	5,321	(1,759)
General and administrative expenses	24,366	23,324	1,042
Total operating expenses	205,498	214,022	(8,524)
Operating loss	(75,215)	(33,635)	(41,580)
Other income (expense):			
Net gain on derivative instruments	14,375	47,072	(32,697)
Interest expense, net of capitalized interest	(38,739)	(38,784)	45
Gain on extinguishment of debt	7,016	—	7,016
Other income (expense)	479	(70)	549
Total other income (expense)	(16,869)	8,218	(25,087)
Loss before income taxes	(92,084)	(25,417)	(66,667)
Income tax benefit	27,629	7,376	20,253
Net loss	$(64,455)	$(18,041)	$(46,414)
Costs and expenses (per Boe of production):			
Lease operating expenses	$6.78	$8.62	$(1.84)
Marketing, transportation and gathering expenses	1.87	1.60	0.27
Production taxes	2.35	3.66	(1.31)
Depreciation, depletion and amortization	26.74	26.10	0.64
General and administrative expenses	5.32	5.14	0.18

Three months ended March 31, 2016 as compared to three months ended March 31, 2015

Lease operating expenses. Lease operating expenses decreased $8.1 million to $31.1 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. This decrease was primarily due to an increase in salt water disposal volumes being transported on OMS pipelines and injected in OMS salt water disposal wells and lower workover costs. Lease operating expenses decreased from $8.62 per Boe for the three months ended March 31, 2015 to $6.78 per Boe for the three months ended March 31, 2016.

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 OMS. The $2.4 million increase for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015 was attributable to a $1.6 million increase in well completion costs as a result of OWS completing OPNA wells with a higher average third-party working interest, offset by lower well completion product sales to third parties due to OWS completing all of OPNA's operated wells during the three months ended March 31, 2016. In addition, midstream operating expenses increased $0.8 million during the three months ended March 31, 2016 as compared to the three months ended March 31, 2016 primarily due to increases in fresh water purchased.

Marketing, transportation and gathering expenses. The $1.3 million increase in marketing, transportation and gathering expenses for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015 was primarily attributable to a $1.2 million increase in our pipeline imbalance and a $0.5 million increase in gas gathering charges related to additional well connections on OMS infrastructure, partially offset by a $0.4 million decrease in oil transportation costs.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 9.2% and 9.6%, respectively, for the three months ended March 31, 2016 and 2015. The production tax rate decreased period over period primarily due to the reduction in the North Dakota oil extraction tax rate, partially offset by an increased weighting of production in North Dakota, which has a higher average production tax rate as compared to Montana. For the three months ended March 31, 2016 and 2015, the percentage of our total production located in North Dakota was 91% and 86%, respectively. In 2015, North Dakota had a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax, resulting in a combined tax rate of 11.5% of crude oil revenues. In 2016, the North Dakota oil extraction tax was reduced to 5%, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion and amortization (“DD&A”). DD&A expense increased $4.0 million to $122.4 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. This increase in DD&A expense for the three months ended March 31, 2016 was a result of an increase in the DD&A rate coupled with production increases from our wells completed during the twelve months ended March 31, 2016. The DD&A rate for the three months ended March 31, 2016 was $26.74 per Boe compared to $26.10 per Boe for the three months ended March 31, 2015. The increase in the DD&A rate was primarily due to lower proved reserves as a result of lower oil and natural gas prices.

Impairment. For the three months ended March 31, 2016, we recorded an impairment loss of $3.6 million to further adjust the carrying value of our properties held for sale to their estimated fair value, determined based on the expected sales price, less costs to sell. No impairment charges of proved oil and gas properties were recorded for the three months ended March 31, 2015. For the three months ended March 31, 2015, we recorded non-cash impairment charges of $5.3 million for unproved properties due to leases that expired during the period and periodic assessments of unproved properties. During the year ended December 31, 2015, we recorded non-cash impairment charges of $5.1 million related to leases that expired during the three months ended March 31, 2016 as a result of periodic assessments of unproved properties because there were no plans to drill or extend the leases prior to their expiration. Consequently, no impairment charges for unproved properties were recorded during the three months ended March 31, 2016 as all leases that expired during that period had been previously impaired.

General and administrative expenses (“G&A”). Our G&A increased $1.0 million to $24.4 million for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. G&A for our OWS and OMS segments increased by $2.0 million and $0.2 million, respectively, for the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. The increase in OWS G&A was primarily due to severance expenses related to reducing OWS to one fracturing fleet during the first quarter of 2016 coupled with an increase related to OWS completing OPNA wells with a higher average third-party working interest during the three months ended March 31, 2016 as compared to the three months ended March 31, 2015. E&P G&A were $21.1 million and $22.3 million for the three months ended March 31, 2016 and 2015, respectively. The $1.2 million decrease in E&P G&A was primarily due to decreased compensation expenses due to a decrease in employee headcount, partially offset by severance expenses during the first quarter of 2016.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $14.4 million net gain on derivative instruments, including net cash settlement receipts of $73.3 million, for the three months ended March 31, 2016, and a $47.1 million net gain on derivative instruments, including net cash settlement receipts of $109.3 million, for the three months ended March 31, 2015. Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Interest expense. Interest expense was relatively flat at $38.7 million for the three months ended March 31, 2016 as compared to $38.8 million for the three months ended March 31, 2015. The slight decrease was due to a decrease in interest expense incurred on borrowings under our revolving credit facility coupled with increased interest costs capitalized, offset by a $1.8 million write-off of unamortized deferred financing costs related to the decrease in the borrowing base under our revolving credit facility during the three months ended March 31, 2016. For the three months ended March 31, 2016 and 2015, the weighted average debt outstanding under our revolving credit facility was $108.0 million and $454.3 million, respectively. The weighted average interest rate incurred on the outstanding borrowings under our revolving credit facility was 1.9% for each of the three months ended March 31, 2016 and 2015. Interest capitalized during the three months ended March 31, 2016 and 2015 was $4.5 million and $3.9 million, respectively. The increase in interest costs capitalized was due to increased work in progress assets, including the natural gas processing plant we are constructing in Wild Basin.

Gain on extinguishment of debt. In March 2016, we repurchased an aggregate principal amount of $29.8 million of our outstanding senior unsecured notes for an aggregate cost of $22.3 million, including interest and fees. For the three months ended March 31, 2016, we recognized a pre-tax gain related to the repurchase of $7.0 million, which included the write-off of $0.5 million of unamortized deferred financing costs. For the three months ended March 31, 2015, we did not repurchase any portion of our outstanding senior unsecured notes.

Income taxes. The income tax benefit for the three months ended March 31, 2016 and 2015 was recorded at 30.0% and 29.0% of pre-tax net income, respectively. The effective tax rates for both periods were lower than the combined federal statutory rate and the statutory rates for the states in which we conduct business due to the impact of permanent differences on our pre-tax loss. The permanent differences were primarily for compensation amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vesting during the three months ended March 31, 2016 and 2015 at stock prices lower than the grant date values. In addition, during the three months ended March 31, 2016, we recorded a valuation allowance of $0.9 million and $0.6 million for Montana net operating losses and federal charitable contribution carryovers, respectively, based on management's assessment that it is more likely than not that these net deferred tax assets will not be realized prior to their expiration due to current economic conditions and expectations for the future.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report have been proceeds from our senior unsecured notes, borrowings under our revolving credit facility, proceeds from public equity offerings, cash flows from operations, the sale of certain non-core oil and gas properties and cash settlements of derivative contracts. Our primary uses of capital have been for the acquisition and development of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings and potential asset monetizations, in order to enhance liquidity and decrease leverage. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Our cash flows for the three months ended March 31, 2016 and 2015 are presented below:

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Net cash provided by (used in) operating activities	$(46,051)	$88,361
Net cash used in investing activities	(30,355)	(250,682)
Net cash provided by financing activities	86,073	126,698
Increase (decrease) in cash and cash equivalents	$9,667	$(35,623)

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. Prices for oil have declined significantly since mid-2014, which has substantially decreased our cash flows provided by operating activities. The decline in operating cash flows caused by lower oil prices is partially offset by cash flows from our derivative contracts. On February 2, 2016, we completed a public equity offering resulting in net proceeds of $183.2 million, after deducting underwriting discounts and commissions and offering expenses, which we used for general corporate purposes. Our existing revolving credit facility provides additional liquidity, with a current borrowing base and elected commitment amount of $1,150.0 million. The next redetermination of the borrowing base is scheduled for October 1, 2016. We believe we have adequate liquidity to fund planned 2016 capital expenditures and to meet our near-term future obligations. For additional information on the impact of changing prices on our financial position, see Item 3. "Quantitative and Qualitative Disclosures about Market Risk" below.

Cash flows provided by operating activities

Net cash used in operating activities was $46.1 million for the three months ended March 31, 2016 and net cash provided by operating activities was $88.4 million for the three months ended March 31, 2015. The change in cash flows from operating activities for the period ended March 31, 2016 as compared to 2015 was primarily the result of lower realized oil and natural gas sales prices coupled with decreases in well completion product sales to third parties,

offset by increases in well completion revenue, salt water transport, salt water disposal and fresh water sales.
Working capital. Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and acquisitions, and the impact of our outstanding derivative instruments. We had a working capital surplus of $43.9 million at March 31, 2016 due to decreases in our current liabilities, including our accrued liabilities for drilling and development costs and accrued interest payable. As of March 31, 2016, we had $1,090.2 million of liquidity available, including $19.4 million in cash and cash equivalents

Table of Contents

and $1,070.8 million of unused borrowing base committed capacity available under our revolving credit facility. At March 31, 2015, we had a working capital deficit of $95.7 million.

Cash flows used in investing activities

Net cash used in investing activities was $30.4 million and $250.7 million during the three months ended March 31, 2016 and 2015, respectively. Net cash used in investing activities during the three months ended March 31, 2016 was primarily attributable to $103.4 million in capital expenditures primarily for drilling and development costs, partially offset by $73.3 million of derivative settlements received as a result of lower commodity prices. Net cash used in investing activities during the three months ended March 31, 2015 was primarily attributable to $359.1 million in capital expenditures primarily for drilling and development costs, partially offset by $109.3 million of derivative settlements as a result of lower commodity prices.

Our capital expenditures are summarized in the following table:

	Three Months Ended March 31, 2016
	(In thousands)
Capital expenditures:	
E&P	$ 47,734
OMS	35,039
OWS	650
Other capital expenditures[1]	4,532
Total capital expenditures[2]	$ 87,955

(1) Other capital expenditures include such items as administrative capital and capitalized interest.

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

Our total 2016 capital expenditure budget is $400 million, which includes $340 million for E&P capital expenditures and $60 million for non-E&P capital expenditures, including OWS, administrative capital and capitalized interest. Our planned E&P capital expenditures include $200 million of drilling and completion capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS) and $140 million of OMS capital expenditures (including Wild Basin infrastructure).

While we have budgeted $400 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. Additionally, if we acquire additional acreage, our capital expenditures may be higher than budgeted. We believe that cash on hand, cash flows from operating activities, proceeds from cash settlements under our derivative contracts and availability under our revolving credit facility should be sufficient to fund our 2016 capital expenditure budget. However, because the operated wells funded by our 2016 drilling plan represent only a small percentage of our potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

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

Cash flows provided by financing activities

Net cash provided by financing activities was $86.1 million and $126.7 million for the three months ended March 31, 2016 and 2015, respectively. For the three months ended March 31, 2016, cash provided by financing activities was primarily due to proceeds from borrowings under our revolving credit facility and net proceeds from the issuance of our common stock,

Table of Contents

partially offset by principal payments on our revolving credit facility and the repurchase of a portion of our outstanding senior unsecured notes. Net cash provided by financing activities during the three months ended March 31, 2015 was primarily due to net proceeds from the issuance of our common stock and proceeds from borrowings under our revolving credit facility, partially offset by principal payments on our revolving credit facility. For both the three months ended March 31, 2016 and 2015, cash was used in financing activities for the purchases of treasury stock for shares that employees surrendered back to us to pay tax withholdings upon the vesting of restricted stock awards.

Sale of common stock. On February 2, 2016 we completed a public offering of 39,100,000 shares of our common stock at an offering price of $4.685 per share. We used the net proceeds from the offering of $183.2 million, after deducting underwriting discounts and commissions and offering expenses, for general corporate purposes.

Senior unsecured notes. As of March 31, 2016, our long-term debt includes outstanding senior unsecured note obligations of $2,170.2 million, including $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the "2019 Notes"), $399.0 million of 6.5% senior unsecured notes due November 1, 2021 (the "2021 Notes"), $985.0 million of 6.875% senior unsecured notes due March 15, 2022 (the "2022 Notes") and $386.2 million of 6.875% senior unsecured notes due January 15, 2023 (the "2023 Notes," and together with the 2019 Notes, the 2021 Notes and the 2022 Notes, the "Notes"). Interest on the Notes is payable semi-annually in arrears.

Prior to certain dates, we have 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, we have 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. We may from time to time seek to retire or purchase our outstanding Notes through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

The Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The indentures governing 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.

In March and April 2016, we repurchased an aggregate principal amount of $76.6 million of our outstanding Notes, consisting of $1.0 million principal amount of our 2019 Notes, $2.3 million principal amount of our 2021 Notes, $59.5 million principal amount of our 2022 Notes and $13.8 million principal amount of our 2023 Notes, for an aggregate cost of $56.9 million, including accrued interest and fees. As a result of this repurchase, we had $399.0 million, $397.7 million, $940.5 million and $386.2 million outstanding on the 2019 Notes, the 2021 Notes, the 2022 Notes and the 2023 Notes, respectively.

Senior secured revolving line of credit. We have a revolving credit facility (the "Credit Facility") with an overall senior secured line of credit of $2,500.0 million as of March 31, 2016. The 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. The maturity date of the Credit Facility is April 13, 2020, provided that the 2019 Notes are retired or refinanced 90 days prior to the maturity of the 2019 Notes. On February 23, 2016, the lenders under the Credit Facility (the "Lenders") completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2016, resulting in a decrease in the borrowing base and aggregate elected commitment from $1,525.0 million to $1,150.0 million. The next redetermination of the borrowing base is scheduled for October 1, 2016.

As of March 31, 2016, we had $65.0 million of borrowings at a weighted average interest rate of 2.4% and $14.2 million of outstanding letters of credit issued under the Credit Facility. As of March 31, 2016, we had unused borrowing base committed capacity of $1,070.8 million.

The Credit Facility contains covenants that include, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;

Table of Contents

- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on our assets and our 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 we maintain a ratio of consolidated EBITDAX (as defined in the Credit Facility) to consolidated Interest Expense (as defined in the 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 we maintain a Current Ratio (as defined in the Credit Facility) of consolidated current assets (including unused borrowing base committed capacity and with exclusions as described in the Credit Facility) to consolidated current liabilities (with exclusions as described in the Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The 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 Credit Facility to be immediately due and payable. We were in compliance with the financial covenants of the Credit Facility as of March 31, 2016. As of March 31, 2016, our consolidated EBITDAX was $744.2 million and our consolidated Interest Expense was $159.2 million, resulting in a ratio of 4.7 as compared to a minimum required ratio of 2.5. In addition, as of March 31, 2016, our consolidated current assets and consolidated current liabilities (as described above) were $1,305.6 million and $281.4 million, respectively, resulting in a Current Ratio of 4.6 as compared to a minimum required ratio of 1.0. Given the extended decline in commodity prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

Obligations and commitments

We have the following contractual obligations and commitments as of March 31, 2016:

	Payments due by period				
Contractual obligations	Total	Within 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Senior unsecured notes[1]	$2,170,200	$—	$400,000	$—	$1,770,200
Interest payments on senior unsecured notes[1]	834,781	149,205	298,410	240,410	146,756
Borrowings under revolving credit facility[1]	65,000	—	—	65,000	—
Interest payments on borrowings under revolving credit facility[1]	234	234	—	—	—
Asset retirement obligations[2]	36,980	892	1,459	629	34,000
Operating leases[3]	24,574	7,300	9,795	7,479	—
Drilling rig commitments[3]	1,764	1,764	—	—	—
Volume commitment agreements[3]	446,211	13,669	102,317	108,550	221,675
Purchase agreements[3]	42,374	564	16,760	16,700	8,350
Total contractual cash obligations	$3,622,118	$173,628	$828,741	$438,768	$2,180,981

(1) See Note 8 to our unaudited condensed consolidated financial statements for a description of our senior unsecured notes, revolving credit facility and related interest payments. As of March 31, 2016, we had $65.0 million of borrowings and $14.2 million of outstanding letters of credit issued under our Credit Facility.

(2) Amounts represent our estimate of future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 9 to our unaudited condensed consolidated financial statements.

(3) See Note 15 to our unaudited condensed consolidated financial statements for a description of our operating leases, drilling rig commitments, volume commitment agreements and purchase agreements.

28

Table of Contents

Non-GAAP Financial Measures

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

Adjusted EBITDA

We define Adjusted EBITDA as earnings (loss) before interest expense, income taxes, DD&A, exploration expenses and other similar non-cash or non-recurring charges. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Management believes that the presentation of Adjusted EBITDA provides useful additional information to investors and analysts for assessing our results of operations and our ability to incur and service debt and to fund capital expenditures.

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

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Net loss	$(64,455)	$(18,041)
Gain on extinguishment of debt	(7,016)	—
Net gain on derivative instruments	(14,375)	(47,072)
Derivative settlements[1]	73,313	109,259
Interest expense, net of capitalized interest	38,739	38,784
Depreciation, depletion and amortization	122,449	118,478
Impairment	3,562	5,321
Rig termination	—	1,080
Exploration expenses	363	843
Stock-based compensation expenses	6,730	7,606
Income tax benefit	(27,629)	(7,376)
Other non-cash adjustments	1,207	(4)
Adjusted EBITDA	$132,888	$208,878
Net cash provided by (used in) operating activities	$(46,051)	$88,361
Derivative settlements[1]	73,313	109,259
Interest expense, net of capitalized interest	38,739	38,784
Rig termination	—	1,080
Exploration expenses	363	843
Deferred financing costs amortization and other	(5,066)	(1,655)
Changes in working capital	70,383	(27,790)
Other non-cash adjustments	1,207	(4)
Adjusted EBITDA	$132,888	$208,878

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

The following tables present reconciliations of the GAAP financial measure of income (loss) before income taxes to the non-GAAP financial measure of Adjusted EBITDA for our three reportable business segments on a gross basis for the periods presented:

Table of Contents

Exploration and Production

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Loss before income taxes	$(105,764)	$(34,008)
Gain on extinguishment of debt	(7,016)	—
Net gain on derivative instruments	(14,375)	(47,072)
Derivative settlements[1]	73,313	109,259
Interest expense, net of capitalized interest	38,739	38,784
Depreciation, depletion and amortization	120,842	117,540
Impairment	1,131	5,321
Rig termination	—	1,080
Exploration expenses	363	843
Stock-based compensation expenses	6,547	7,542
Other non-cash adjustments	1,207	(4)
Adjusted EBITDA	$114,987	$199,285

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

Well Services

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Income before income taxes	$4,011	$9,608
Depreciation, depletion and amortization	4,248	4,518
Stock-based compensation expenses	664	543
Adjusted EBITDA	$8,923	$14,669

Midstream Services

	Three Months Ended March 31,	
	2016	2015
	(In thousands)	
Income before income taxes	$15,157	$9,289
Depreciation, depletion and amortization	1,684	1,186
Impairment	2,431	—
Stock-based compensation expenses	219	204
Adjusted EBITDA	$19,491	$10,679

Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) Per Share

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

Table of Contents

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

	Three Months Ended March 31,	
	2016	2015
	(In thousands, except per share data)	
Net loss	$ (64,455)	$ (18,041)
Gain on extinguishment of debt	(7,016)	—
Net gain on derivative instruments	(14,375)	(47,072)
Derivative settlements(1)	73,313	109,259
Impairment	3,562	5,321
Rig termination	—	1,080
Other non-cash adjustments	1,207	(4)
Tax impact(2)	(21,191)	(25,719)
Adjusted Net Income (Loss)	$ (28,955)	$ 24,824
Diluted loss per share	$ (0.40)	$ (0.17)
Gain on extinguishment of debt	(0.04)	—
Net gain on derivative instruments	(0.09)	(0.43)
Derivative settlements(1)	0.45	1.00
Impairment	0.02	0.05
Rig termination	—	0.01
Other non-cash adjustments	0.01	—
Tax impact(2)	(0.13)	(0.23)
Adjusted Diluted Earnings (Loss) Per Share	$ (0.18)	$ 0.23
Diluted weighted average shares outstanding	162,922	109,303
Effective tax rate applicable to adjustment items	37.4 %	37.5 %

(1) Cash settlements represent the cumulative gains and losses on our derivative instruments for the periods presented and do not include a recovery of costs that were paid to acquire or modify the derivative instruments that were settled.

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

Fair Value of Financial Instruments

See Note 4 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 2015 Annual Report.

Recent accounting pronouncements

Revenue recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Deferral of the Effective Date (“ASU 2015-14”). ASU

2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. In March 2016, the FASB issued Accounting Standards Update No. 2016-08, Principal versus Agent Considerations (Reporting Revenue Gross versus Net), which clarifies the implementation guidance on principal versus agent considerations on such matters. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Going concern. In August 2014, the FASB issued Accounting Standards Update No. 2014-15, Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 codifies in GAAP management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and to provide related footnote disclosures. ASU 2014-15 is effective for the annual reporting period ending after December 15, 2016 and for annual periods and interim periods thereafter. The adoption of this guidance will not impact our financial position, cash flows or results of operations, but could result in additional disclosures.

Inventory. In July 2015, the FASB issued Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"). ASU 2015-11 changes the inventory measurement principle from lower of cost or market to lower of cost and net realizable value for entities using the first-in, first-out (FIFO) or average cost methods. ASU 2015-11 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Financial instruments. In January 2016, the FASB issued Accounting Standards Update No. 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities ("ASU 2016-01"), which requires that most equity instruments be measured at fair value with subsequent changes in fair value recognized in net income. ASU 2016-01 also impacts financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. ASU 2016-01 does not apply to equity method investments or investments in consolidated subsidiaries. ASU 2016-01 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Leases. In February 2016, the FASB issued Accounting Standards Update No. 2016-02, Leases ("ASU 2016-02"), which requires a lessee to recognize lease payment obligations and a corresponding right-of-use asset to be measured at fair value on the balance sheet. ASU 2016-02 also requires certain qualitative and quantitative disclosures about the amount, timing and uncertainty of cash flows arising from leases. ASU 2016-02 is effective for fiscal years beginning after December 15, 2018, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Embedded derivatives. In March 2016, the FASB issued Accounting Standards Update No. 2016-06, Contingent Put and Call Options in Debt Instruments ("ASU 2016-06"), which clarifies what steps are required when assessing whether the economic characteristics and risks of call (put) options are clearly and closely related to the economic characteristics and risks of their debt hosts, which is one of the criteria for bifurcating an embedded derivative. ASU 2016-06 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Stock-based compensation. In March 2016, the FASB issued Accounting Standards Update No. 2016-09, Improvements to Employee Share-Based Payment Accounting ("ASU 2016-09"), which updates several aspects of the accounting for share-based payment transactions, including recognition of excess tax benefits and deficiencies, the classification of those excess tax benefits on the statement of cash flows, an accounting policy election for forfeitures, the amount an employer can withhold to cover income taxes and still qualify for equity classification and the classification of those taxes paid on the statement of cash flows. ASU 2016-09 is effective for fiscal years beginning after December 15, 2016, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See Note 15 to our unaudited condensed consolidated financial statements for a description of our commitments and contingencies.

32

Table of Contents

Item 3. — Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2015 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 March 31, 2016, we utilized two-way costless collar options and swaps 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 swap is a sold call and a purchased put established at the same price (both ceiling and floor).

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 March 31, 2016:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices			Fair Value
			Swap	Floor	Ceiling	
		(Barrels)	($/Barrel)			(In thousands)
2016	Swaps	8,707,000	$50.60			$ 82,960
2017	Swaps	3,967,000	$48.01			13,906
2017	Two-way collars	668,000		$40.00	$47.58	(638)
2018	Swaps	279,000	$47.61			433
2018	Two-way collars	62,000				(126)
						$ 96,535

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) $399.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum and (iii) $1,371.2 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum outstanding at March 31, 2016. At March 31, 2016, we had $65.0 million of borrowings and $14.2 million letters of credit outstanding under our Credit Facility, which were subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a LIBOR loan or a domestic bank prime interest rate loan (defined in the Credit Facility as an Alternate Based Rate or "ABR" loan). At March 31, 2016, the outstanding borrowings under our Credit Facility bore interest at LIBOR plus a 1.5% margin. 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 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 Credit Facility. This risk is also managed by spreading our derivative exposure across several institutions and limiting the volumes placed under individual contracts. We are likely to enter into future derivative instruments with these or other Lenders under our 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

Table of Contents

the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $96.5 million at March 31, 2016.

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

We may, from time to time, purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial sector. Our investment policy requires that our counterparties have minimum credit ratings thresholds and provides maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers being unable to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If a commercial paper issuer is unable to return investment proceeds to us at the maturity date, it could take a significant amount of time to recover all or a portion of the assets originally invested. Our commercial paper balance was $36,000 at March 31, 2016.

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, and our Chief Financial Officer ("CFO"), our principal financial officer, 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 March 31, 2016. 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 and CFO as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, our CEO and CFO have concluded that our disclosure controls and procedures were effective at March 31, 2016.

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 March 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

PART II — OTHER INFORMATION

Item 1. — Legal Proceedings

See Part I, Item 1, Note 15 to our unaudited condensed consolidated financial statements entitled “Commitments and Contingencies,” which is incorporated in this item by reference.

Item 1A. — Risk Factors

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

For a discussion of our potential risks and uncertainties, see the information in Item 1A. “Risk Factors” in our 2015 Annual Report. There have been no material changes in our risk factors from those described in our 2015 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 March 31, 2016:

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
January 1 - January 31, 2016	113,618	$ 4.85	—	—
February - February 29, 2016	68,341	4.55	—	—
March 1 - March 31, 2016	25,261	6.76	—	—
Total	207,220	4.98	—	—

(1) Represent shares that employees surrendered back to us to pay tax withholdings upon the vesting of restricted stock awards. These repurchases were not part of a publicly announced program to repurchase shares of our common stock, nor do we have a publicly announced program to repurchase shares of our common stock.

Table of Contents

Item 6. — Exhibits

Exhibit No.	Description of Exhibit
10.1	Fifth Amendment to Second Amended and Restated Credit Agreement dated as of February 23, 2016 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 10.35 to the Company's Annual Report on Form 10-K on February 25, 2016, and incorporated herein by reference).
10.2(a)	Form of Notice of Grant of Performance Share Units.
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS (a)	XBRL Instance Document.
101.SCH (a)	XBRL Schema Document.
101.CAL (a)	XBRL Calculation Linkbase Document.
101.DEF (a)	XBRL Definition Linkbase Document.
101.LAB (a)	XBRL Labels Linkbase Document.
101.PRE (a)	XBRL Presentation Linkbase Document.

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

Table of Contents

SIGNATURES

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

OASIS PETROLEUM INC.

Date: May 10, 2016 By: /s/ Thomas B. Nusz

Thomas B. Nusz
Chairman and Chief Executive Officer
(Principal Executive Officer)

By: /s/ Michael H. Lou
Michael H. Lou
Executive Vice President and Chief Financial Officer
(Principal Financial Officer and Principal Accounting Officer)

Table of Contents

EXHIBIT INDEX

Exhibit No.	Description of Exhibit
10.1	Fifth Amendment to Second Amended and Restated Credit Agreement dated as of February 23, 2016 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 10.35 to the Company’s Annual Report on Form 10-K on February 25, 2016, and incorporated herein by reference).
10.2(a)	Form of Notice of Grant of Performance Share Units.
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.