Oasis Petroleum Inc.
Form 10-Q
August 03, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-34776

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer”, “smaller reporting company” and “emerging growth 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 ¨
	Emerging growth company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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 July 31, 2017: 237,415,441 shares.

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

	June 30, 2017	December 31, 2016
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 11,440	$ 11,226
Accounts receivable, net	218,302	204,335
Inventory	17,942	10,648
Prepaid expenses	10,610	7,623
Derivative instruments	31,851	362
Other current assets	62	4,355
Total current assets	290,207	238,549
Property, plant and equipment		
Oil and gas properties (successful efforts method)	7,488,075	7,296,568
Other property and equipment	695,592	618,790
Less: accumulated depreciation, depletion, amortization and impairment	(2,252,653)	(1,995,791)
Total property, plant and equipment, net	5,931,014	5,919,567
Derivative instruments	11,834	—
Long-term inventory	8,762	—
Other assets	19,904	20,516
Total assets	$ 6,261,721	$ 6,178,632
LIABILITIES AND STOCKHOLDERS’ EQUITY		
Current liabilities		
Accounts payable	$ 12,257	$ 4,645
Revenues and production taxes payable	143,715	139,737
Accrued liabilities	139,766	119,173
Accrued interest payable	39,128	39,004
Derivative instruments	—	60,469
Advances from joint interest partners	5,816	7,597
Other current liabilities	—	10,490
Total current liabilities	340,682	381,115
Long-term debt	2,359,683	2,297,214
Deferred income taxes	527,181	513,529
Asset retirement obligations	51,059	48,985
Derivative instruments	—	11,714
Other liabilities	5,506	2,918
Total liabilities	3,284,111	3,255,475
Commitments and contingencies (Note 13)		
Stockholders’ equity		
Common stock, $0.01 par value: 450,000,000 shares authorized; 238,642,598 shares issued and 237,410,395 shares outstanding at June 30, 2017 and 237,201,064 shares issued and 236,344,172 shares outstanding at December 31, 2016	2,345	2,331
Treasury stock, at cost: 1,232,203 and 856,892 shares at June 30, 2017 and December 31, 2016, respectively	(21,401)	(15,950)

Additional paid-in capital	2,362,084	2,345,271
Retained earnings	634,582	591,505
Total stockholders’ equity	2,977,610	2,923,157
Total liabilities and stockholders’ equity	$ 6,261,721	$ 6,178,632

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands, except per share data)			
Revenues				
Oil and gas revenues	$218,633	$159,337	$455,885	$276,652
Bulk oil sales	8,091	—	35,722	—
Midstream revenues	15,566	6,910	30,172	13,893
Well services revenues	11,801	12,833	17,428	18,818
Total revenues	254,091	179,080	539,207	309,363
Operating expenses				
Lease operating expenses	44,665	31,523	88,537	62,587
Midstream operating expenses	3,263	1,740	6,590	3,478
Well services operating expenses	8,088	7,135	11,990	9,786
Marketing, transportation and gathering expenses	12,039	6,491	22,990	15,043
Bulk oil purchases	7,980	—	35,982	—
Production taxes	18,971	14,367	39,270	25,120
Depreciation, depletion and amortization	125,291	122,488	251,957	244,937
Exploration expenses	1,667	340	3,156	703
Impairment	3,200	23	5,882	3,585
General and administrative expenses	23,548	21,876	47,382	46,242
Total operating expenses	248,712	205,983	513,736	411,481
Loss on sale of properties	—	(1,311)	—	(1,311)
Operating income (loss)	5,379	(28,214)	25,471	(103,429)
Other income (expense)				
Net gain (loss) on derivative instruments	50,532	(90,846)	106,607	(76,471)
Interest expense, net of capitalized interest	(36,838)	(34,979)	(73,159)	(73,718)
Gain on extinguishment of debt	—	11,642	—	18,658
Other income (expense)	(166)	(32)	(150)	447
Total other income (expense)	13,528	(114,215)	33,298	(131,084)
Income (loss) before income taxes	18,907	(142,429)	58,769	(234,513)
Income tax benefit (expense)	(2,339)	52,498	(18,376)	80,127
Net income (loss)	$16,568	$(89,931)	$40,393	$(154,386)
Earnings (loss) per share:				
Basic (Note 11)	$0.07	$(0.51)	$0.17	$(0.91)
Diluted (Note 11)	0.07	(0.51)	0.17	(0.91)
Weighted average shares outstanding:				
Basic (Note 11)	233,283	176,984	233,176	169,953
Diluted (Note 11)	234,917	176,984	236,281	169,953

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

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

	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
	(In thousands)						
Balance at December 31, 2016	236,344	$ 2,331	857	$ (15,950)	$ 2,345,271	$ 591,505	$ 2,923,157
Cumulative-effect adjustment for adoption of ASU 2016-09 (Note 2)	—	—	—	—	2,040	2,684	4,724
Fees (2016 issuance of common stock)	—	—	—	—	(55)	—	(55)
Stock-based compensation	1,441	14	—	—	14,828	—	14,842
Treasury stock - tax withholdings	(375)	—	375	(5,451)	—	—	(5,451)
Net income	—	—	—	—	—	40,393	40,393
Balance at June 30, 2017	237,410	$ 2,345	1,232	$ (21,401)	$ 2,362,084	$ 634,582	$ 2,977,610

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

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

	Six Months Ended June 30, 2017	2016
	(In thousands)	
Cash flows from operating activities:		
Net income (loss)	$40,393	$(154,386)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, depletion and amortization	251,957	244,937
Gain on extinguishment of debt	—	(18,658)
Loss on sale of properties	—	1,311
Impairment	5,882	3,585
Deferred income taxes	18,376	(80,127)
Derivative instruments	(106,607)	76,471
Stock-based compensation expenses	13,823	12,979
Deferred financing costs amortization and other	8,871	6,552
Working capital and other changes:		
Change in accounts receivable	(13,743)	4,297
Change in inventory	(1,007)	2,054
Change in prepaid expenses	(264)	1,423
Change in other current assets	280	(114)
Change in long-term inventory and other assets	(8,768)	100
Change in accounts payable, interest payable and accrued liabilities	11,158	(18,034)
Change in other current liabilities	(10,490)	9,001
Change in other liabilities	—	10
Net cash provided by operating activities	209,861	91,401
Cash flows from investing activities:		
Capital expenditures	(252,461)	(231,341)
Proceeds from sale of properties	4,000	11,679
Costs related to sale of properties	—	(310)
Derivative settlements	(8,899)	103,790
Advances from joint interest partners	(1,781)	769
Net cash used in investing activities	(259,141)	(115,413)
Cash flows from financing activities:		
Proceeds from revolving credit facility	484,000	359,000
Principal payments on revolving credit facility	(429,000)	(462,000)
Repurchase of senior unsecured notes	—	(56,925)
Deferred financing costs	—	(751)
Proceeds from sale of common stock	—	182,953
Purchases of treasury stock	(5,451)	(1,520)
Other	(55)	—
Net cash provided by financing activities	49,494	20,757
Increase (decrease) in cash and cash equivalents	214	(3,255)
Cash and cash equivalents:		
Beginning of period	11,226	9,730
End of period	$11,440	$6,475
Supplemental non-cash transactions:		

Change in accrued capital expenditures	$19,017	$(17,015)
Change in asset retirement obligations	1,759	(8,785)
Notes payable from acquisition	4,875	—

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

OASIS PETROLEUM INC.
Notes to Condensed Consolidated Financial Statements (Unaudited)

1. Organization and Operations of the Company

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 midstream services business through Oasis Midstream Services LLC ("OMS") and a well services business through Oasis Well Services LLC ("OWS"), 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, 2016 is derived from audited financial statements. Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income. In the opinion of management, all adjustments, consisting of normal recurring adjustments necessary for the fair statement, 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, 2016 ("2016 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. 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 2016 Annual Report, other than as noted below.

Stock-based compensation. In the first quarter of 2017, the Company adopted 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. In accordance with the new guidance, the Company recorded a $2.7 million cumulative-effect adjustment to retained earnings on the Company's Condensed Consolidated Balance Sheet as of June 30, 2017, which included recognition of excess tax benefits and

deficiencies and the removal of the estimated forfeiture rate. ASU 2016-09 was applied on a modified retrospective basis and prior periods were not retrospectively adjusted.
Inventory. In the first quarter of 2017, the Company adopted Accounting Standards Update No. 2015-11, Simplifying the Measurement of Inventory ("ASU 2015-11"), which 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 or average cost methods. ASU 2015-11 was

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applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of June 30, 2017.

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 2016, the FASB issued additional accounting standards updates to clarify the implementation guidance of ASU 2014-09. 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.

Statement of cash flows. In August 2016, the FASB issued Accounting Standards Update No. 2016-15, Statement of Cash Flows ("ASU 2016-15"), which is intended to reduce diversity in practice in how certain transactions are classified in the statement of cash flows. ASU 2016-15 is effective for fiscal years beginning after December 15, 2017, including interim periods within those years. The adoption of this guidance will not impact the Company's financial position or results of operations, but could result in presentation changes on the Company's statement of cash flows.

Business combinations. In January 2017, the FASB issued Accounting Standards Update No. 2017-01, Clarifying the Definition of a Business ("ASU 2017-01"), which provides guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 requires entities to use a screen test to determine when an integrated set of assets and activities is not a business or if the integrated set of assets and activities needs to be further evaluated against the framework. ASU 2017-01 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.

Stock-based compensation. In May 2017, the FASB issued Accounting Standards Update No. 2017-09, Scope of Modification Accounting ("ASU 2017-09"), which provides guidance about which changes to the terms or conditions of a share-based payment award require an entity to apply modification accounting. The adoption of ASU 2017-09 will become effective for annual periods beginning after December 15, 2017, and the Company is currently evaluating the impact that it will have on its financial position, cash flows and results of operations.

3. Inventory

Crude oil inventory includes oil in tank. Equipment and materials consist primarily of proppant, chemicals, tubular goods, well equipment to be used in future drilling or repair operations and well fracturing equipment. Crude oil inventory and equipment and materials are included in Inventory on the Company's Condensed Consolidated Balance

Sheets.
The minimum volume of product in a pipeline system that enables the system to operate is known as linefill and is generally not available to be withdrawn from the pipeline system until the expiration of the transportation contract. The Company owns oil linefill in third-party pipelines, which is included in Long-term inventory on the Company's Condensed Consolidated Balance Sheets.

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Inventory, including long-term inventory, is stated at the lower of cost and net realizable value with cost determined on an average cost method. The Company assesses the carrying value of inventory and uses estimates and judgment when making any adjustments necessary to reduce the carrying value to net realizable value. Among the uncertainties that impact the Company's estimates are the applicable quality and location differentials to include in the Company's net realizable value analysis. Additionally, the Company estimates the upcoming liquidation timing of the inventory. Changes in assumptions made as to the timing of a sale can materially impact net realizable value.

Total inventory consists of the following:

	June 30, 2017	December 31, 2016
	(In thousands)	
Inventory		
Crude oil inventory	$7,846	$ 7,086
Equipment and materials	10,096	3,562
Total inventory	$17,942	$ 10,648
Long-term inventory		
Linefill in third-party pipelines	$8,762	$ —
Long-term inventory	$8,762	$ —
Total	$26,704	$ 10,648

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's financial instruments, including certain cash and cash equivalents, accounts receivable, accounts payable and other payables, are carried at cost, which approximates their respective fair market values due to their short-term maturities. The Company recognizes its non-financial assets and liabilities, such as asset retirement obligations ("ARO") and proved oil and natural gas properties upon impairment, at fair value on a non-recurring basis.

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

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

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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:

	Fair value at June 30, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$142	$—	$ —	$142
Commodity derivative instruments (see Note 5)	—	43,685	—	43,685
Total assets	$142	$43,685	$ —	$43,827

	Fair value at December 31, 2016			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$141	$—	$ —	$141
Commodity derivative instruments (see Note 5)	—	362	—	362
Total assets	$141	$362	$ —	$503
Liabilities:				
Commodity derivative instruments (see Note 5)	$—	$72,183	$ —	$72,183
Total liabilities	$—	$72,183	$ —	$72,183

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 Sheets at June 30, 2017 and December 31, 2016. 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 and natural gas swaps and collars. 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. 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 and natural gas 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 $41,000 at June 30, 2017 and an adjustment to reduce the fair value of its net derivative liability by $2.0 million at December 31, 2016.

There were no transfers between fair value levels during the six months ended June 30, 2017 and 2016.

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5. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil and natural gas prices. The Company’s crude oil and natural gas contracts will settle monthly based on the average NYMEX West Texas Intermediate crude oil index price (“WTI”) and the average NYMEX Henry Hub natural gas index price (“Henry Hub”), respectively. At June 30, 2017, the Company utilized swaps and two-way and three-way costless collar options to reduce the volatility of oil and natural gas prices on a significant portion of its future expected oil and natural gas production. A swap is a sold call and a purchased put established at the same price (both ceiling and floor), which the Company will receive for the volumes under contract. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the NYMEX index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract.

All derivative instruments are recorded on the Company’s Condensed Consolidated Balance Sheets 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 Statements 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 Statements of Cash Flows.

At June 30, 2017, the Company had the following outstanding commodity derivative instruments:

Commodity	Settlement Period	Derivative Instrument	Volumes		Weighted Average Prices				Fair Value Asset (Liability)
					Swap	Sub-Floor	Floor	Ceiling	
									(In thousands)
Crude oil	2017	Swaps	3,843,000	Bbl	$49.83				$ 13,211
Crude oil	2017	Two-way collar	1,464,000	Bbl			$46.25	$54.37	3,122
Crude oil	2017	Three-way collar	1,098,000	Bbl		$ 31.67	$45.83	$59.94	1,816
Crude oil	2018	Swaps	5,508,000	Bbl	$51.95				20,746
Crude oil	2018	Two-way collar	582,000	Bbl			$48.40	$55.13	1,799
Crude oil	2018	Three-way collar	186,000	Bbl		$ 31.67	$45.83	$59.94	452
Crude oil	2019	Swaps	434,000	Bbl	$52.16				1,365
Crude oil	2019	Two-way collar	31,000	Bbl			$50.00	$55.70	104
Natural gas	2017	Swaps	3,680,000	MMBtu	$3.32				827
Natural gas	2018	Swaps	5,475,000	MMBtu	$3.04				243
									$ 43,685

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 Statements of Operations for the periods presented:

Statement of Operations Location	Three Months Ended June 30, 2017	Three Months Ended June 30, 2016	Six Months Ended June 30, 2017	Six Months Ended June 30, 2016
	(In thousands)			
Net gain (loss) on derivative instruments	$50,532	$(90,846)	$106,607	$(76,471)

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 Sheets.

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

Commodity	Balance Sheet Location	June 30, 2017 Gross Recognized Assets	Gross Amount Offset	Net Recognized Fair Value Assets
		(In thousands)		
Derivatives assets:				
Commodity contracts	Derivative instruments — current assets	$37,829	$(5,978)	$ 31,851
Commodity contracts	Derivative instruments — non-current assets	12,482	(648)	11,834
Total derivatives assets		$50,311	$(6,626)	$ 43,685

Commodity	Balance Sheet Location	December 31, 2016 Gross Recognized Asset/Liabilities	Gross Amount Offsets	Net Recognized Fair Value Asset/Liabilities
		(In thousands)		
Derivatives assets:				
Commodity contracts	Derivative instruments — current assets	$482	$(120)	$ 362
Total derivatives assets		$482	$(120)	$ 362
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$66,838	$(6,369)	$ 60,469
Commodity contracts	Derivative instruments — non-current liabilities	14,164	(2,450)	11,714
Total derivatives liabilities		$81,002	$(8,819)	$ 72,183

6. Property, Plant and Equipment

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

	June 30, 2017	December 31, 2016
	(In thousands)	
Proved oil and gas properties[(1)]	$6,671,833	$6,476,833
Less: accumulated depreciation, depletion, amortization and impairment	(2,130,330)	(1,886,732)
Proved oil and gas properties, net	4,541,503	4,590,101
Unproved oil and gas properties	816,242	819,735
Other property and equipment	695,592	618,790
Less: accumulated depreciation	(122,323)	(109,059)
Other property and equipment, net	573,269	509,731
Total property, plant and equipment, net	$5,931,014	$5,919,567

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $43.3 million and $42.9 million at June 30, 2017 and December 31, 2016, respectively.

Midstream assets acquisition. On April 25, 2017, the Company completed purchase and sale agreements with two undisclosed private sellers to acquire certain midstream assets in McKenzie County, North Dakota for total consideration of $12.7 million, which includes $4.9 million of installment notes payable. Based on the FASB's authoritative guidance, the acquisition qualified as a business combination, and as such, the Company estimated the fair value of the assets acquired as of the acquisition date. The Company recorded the assets acquired at their estimated fair value of $12.7 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized.

The results of operations for the acquisition have been included in the Company's condensed consolidated financial statements since the closing date. Pro forma information is not presented as the pro forma results would not be materially different from the information presented in the Company’s Condensed Consolidated Statement of Operations.

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7. Long-Term Debt

The Company’s long-term debt consists of the following:

	June 30, 2017	December 31, 2016
	(In thousands)	
Senior secured revolving line of credit	$418,000	$363,000
Senior unsecured notes		
7.25% senior unsecured notes due February 1, 2019	54,275	54,275
6.5% senior unsecured notes due November 1, 2021	395,501	395,501
6.875% senior unsecured notes due March 15, 2022	937,080	937,080
6.875% senior unsecured notes due January 15, 2023	366,094	366,094
2.625% senior unsecured convertible notes due September 15, 2023	300,000	300,000
Total principal of senior unsecured notes	2,052,950	2,052,950
Less: unamortized deferred financing costs on senior unsecured notes	(25,634)	(28,268)
Less: unamortized debt discount on senior unsecured convertible notes	(85,633)	(90,468)
Total long-term debt	$2,359,683	$2,297,214

The carrying amount of the Company’s long-term debt reported in the Condensed Consolidated Balance Sheet at June 30, 2017 was $2,359.7 million, which included $2,053.0 million of senior unsecured notes, a reduction for the unamortized debt discount related to the equity component of the senior unsecured convertible notes and a reduction for the unamortized deferred financing costs on the senior unsecured notes of $85.6 million and $25.6 million, respectively, and $418.0 million of borrowings under the revolving credit facility. The Company’s revolving credit facility is recorded at a value that approximates its fair value since its variable interest rate is tied to current market rates. The fair value of the Company’s senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, was $1,994.8 million at June 30, 2017.

Senior secured revolving line of credit. The Company has a senior secured revolving line of credit (the “Credit Facility”) of $2,500.0 million as of June 30, 2017, which has a maturity date of April 13, 2020, provided that the 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”), of which $54.3 million is outstanding, are retired or refinanced 90 days prior to their maturity. 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 April 10, 2017, the lenders under the Credit Facility (the “Lenders”) completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2017, resulting in an increase in the borrowing base from $1,150.0 million to $1,600.0 million; however, the Company elected to limit the Lenders’ aggregate commitment to $1,150.0 million.

At June 30, 2017, the Company had $418.0 million of LIBOR loans at a weighted average interest rate of 3.0% and $10.0 million of outstanding letters of credit issued under the Credit Facility, resulting in an unused borrowing base committed capacity of $722.0 million. On a quarterly basis, the Company also pays a 0.375% (as of June 30, 2017) 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 June 30, 2017.

Senior unsecured notes. At June 30, 2017, the Company had $1,753.0 million principal amount of senior unsecured notes outstanding with maturities ranging from February 2019 to January 2023 and coupons ranging from 6.50% to 7.25% (the “Senior Notes”). Prior to certain dates, the Company has the option to redeem some or all of the Senior 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 2019 Notes are currently redeemable for cash at a redemption price equal to par plus accrued and unpaid interest to the redemption date.

Senior unsecured convertible notes. In September 2016, the Company issued $300.0 million of 2.625% senior unsecured convertible notes due September 2023 (the “Senior Convertible Notes”). The Company has the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company’s intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. Prior to March 15, 2023, the Senior Convertible Notes will be convertible only under the following circumstances: (i) during any calendar quarter (and only during such calendar quarter), if the last reported sale price of the Company's common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading

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price per $1,000 principal amount of the Senior Convertible Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of the Company's common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events, including certain distributions or a fundamental change. On or after March 15, 2023, the Senior Convertible Notes will be convertible at any time until the second scheduled trading day immediately preceding their September 15, 2023 maturity date. The Senior Convertible Notes will be convertible at an initial conversion rate of 76.3650 shares of the Company's common stock per $1,000 principal amount of the Senior Convertible Notes, which is equivalent to an initial conversion price of approximately $13.10. The conversion rate will be subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date or a notice of redemption, the Company will increase the conversion rate for a holder who elects to convert its Senior Convertible Notes in connection with such corporate event or redemption in certain circumstances. As of June 30, 2017, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met.

Upon issuance, the Company separately accounted for the liability and equity components of the Senior Convertible Notes in accordance with Accounting Standards Codification 470-20. The liability component was recorded at the estimated fair value of a similar debt instrument without the conversion feature. The difference between the principal amount of the Senior Convertible Notes and the estimated fair value of the liability component was recorded as a debt discount and will be amortized to interest expense over the term of the notes using the effective interest method, with an effective interest rate of 8.97% per annum. The fair value of the Senior Convertible Notes as of the issuance date was estimated at $206.8 million, resulting in a debt discount at inception of $93.2 million. The equity component, representing the value of the conversion option, was computed by deducting the fair value of the liability component from the initial proceeds of the Senior Convertible Notes issuance. This equity component was recorded, net of deferred taxes and issuance costs, in additional paid-in capital and will not be remeasured as long as it continues to meet the conditions for equity classification.

Interest on the Senior Notes and the Senior Convertible Notes (collectively, 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.

8. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the six months ended June 30, 2017:

	(In thousands)
Balance at December 31, 2016	$ 49,687
Liabilities incurred during period	661
Liabilities settled during period	(101)
Accretion expense during period[1]	1,316
Revisions to estimates	(214)
Balance at June 30, 2017	$ 51,349

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

At June 30, 2017, the current portion of the total ARO balance was approximately $0.3 million and was included in accrued liabilities on the Company's Condensed Consolidated Balance Sheet.

9. Income Taxes

The Company's effective tax rate for the three and six months ended June 30, 2017 was 12.4% and 31.3%, respectively. The effective tax rate for the three and six months ended June 30, 2017 was 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 and a forecasted annual pre-tax loss for 2017. The Company's effective tax rate for the three and six months ended June 30, 2016 was 36.9% and 34.2%, respectively. The effective tax rate for the three and six months ended June 30, 2016 was 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 pre-tax loss for the period. During both the three and six months ended June 30, 2017 and 2016, the permanent differences were primarily between amounts expensed for book purposes versus the amounts deductible for income tax purposes related to compensation.

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10. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its Amended and Restated 2010 Long Term Incentive Plan, the majority of which vest over a three-year period. The fair value of restricted stock awards 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.

During the six months ended June 30, 2017, employees and non-employee directors of the Company were granted restricted stock awards equal to 1,588,010 shares of common stock with a $15.24 weighted average grant date per share value. Stock-based compensation expense recorded for restricted stock awards for the three and six months ended June 30, 2017 was $4.9 million and $10.3 million, respectively, and $4.9 million and $10.7 million for the three and six months ended June 30, 2016, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statements 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.

During the six months ended June 30, 2017, officers of the Company were granted 509,800 PSUs with a $16.89 weighted average grant date per share value. Stock-based compensation expense recorded for PSUs for the three and six months ended June 30, 2017 was $2.2 million and $3.5 million, respectively, and $1.3 million and $2.2 million for the three and six months ended June 30, 2016, respectively. Stock-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statements 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. 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. 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 rates are the U.S. Treasury bond rates on the date of grant that correspond to each 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 was calculated from the daily historical returns of 30-day volume weighted average stock prices over a historical period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the PSUs granted during the six months ended June 30, 2017:

Risk-free interest rate	1.18% - 1.66%	
Oasis volatility	17.16	%

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11. 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 potential dilutive impact of unvested restricted stock awards and contingently issuable shares related to PSUs and senior convertible notes during the periods presented, unless their effect is anti-dilutive. There are no adjustments made to the income (loss) available 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 and six months ended June 30, 2017 and 2016:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Basic weighted average common shares outstanding	233,283	176,984	233,176	169,953
Dilutive effect of restricted stock awards and PSUs[1]	1,634	—	3,105	—
Diluted weighted average common shares outstanding	234,917	176,984	236,281	169,953

(1) No unvested stock awards were included in computing loss per share for the three and six months ended June 30, 2016 because the effect was anti-dilutive.

The following is a calculation of weighted average common shares excluded from diluted earnings (loss) per share due to the anti-dilutive effect:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Restricted stock awards and PSUs	4,369	4,920	2,957	4,794

The Company issued its Senior Convertible Notes in September 2016 (see Note 7 – Long-Term Debt). The Company has the option to settle conversions of its Senior Convertible Notes with cash, shares of common stock or a combination of cash and common stock at its election. The Company's intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. As a result, only the amount by which the conversion value exceeds the aggregate principal amount of the notes (conversion spread) is considered in the diluted earnings per share computation under the treasury stock method. As of the three and six months ended June 30, 2017, the conversion value did not exceed the principal amount of the notes, and accordingly, there was no impact to diluted earnings per share for the three and six months ended June 30, 2017.

12. 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 midstream services business segment (OMS) performs salt water gathering and disposal services, fresh water services, natural gas gathering and processing and crude oil gathering and transportation 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, fresh water sales, natural gas gathering and processing and crude oil gathering, blending, stabilization and transportation. 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 services, product sales and equipment rentals. The revenues and expenses related to work performed by OMS and OWS 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 Statements of Operations. These segments represent the Company's three operating units, each offering different products and services. The Company's corporate activities have been allocated to the supported business segments accordingly.

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Management evaluates the performance of the Company’s business segments based on operating income. The following table summarizes financial information for the Company’s three business segments for the periods presented:

	Exploration and Production	Midstream Services	Well Services	Eliminations	Consolidated
	(In thousands)				
Three months ended June 30, 2017:					
Revenues from non-affiliates	$226,724	$15,566	$11,801	$—	$254,091
Inter-segment revenues	—	24,746	21,650	(46,396)	—
Total revenues	226,724	40,312	33,451	(46,396)	254,091
Operating income (loss)	(17,425)	23,103	1,950	(2,249)	5,379
Other income	13,525	3	—	—	13,528
Income (loss) before income taxes	$(3,900)	$23,106	$1,950	$(2,249)	$18,907
Three months ended June 30, 2016:					
Revenues from non-affiliates	$159,337	$6,910	$12,833	$—	$179,080
Inter-segment revenues	—	22,025	8,302	(30,327)	—
Total revenues	159,337	28,935	21,135	(30,327)	179,080
Operating income (loss)	(44,748)	18,056	(2,173)	651	(28,214)
Other income (expense)	(114,230)	(16)	31	—	(114,215)
Income (loss) before income taxes	$(158,978)	$18,040	$(2,142)	$651	$(142,429)
Six months ended June 30, 2017:					
Revenues from non-affiliates	$491,607	$30,172	$17,428	$—	$539,207
Inter-segment revenues	—	47,781	37,003	(84,784)	—
Total revenues	491,607	77,953	54,431	(84,784)	539,207
Operating income (loss)	(16,456)	43,865	(1,641)	(297)	25,471
Other income	33,292	2	4	—	33,298
Income (loss) before income taxes	$16,836	$43,867	$(1,637)	$(297)	$58,769
Six months ended June 30, 2016:					
Revenues from non-affiliates	$276,652	$13,893	$18,818	$—	$309,363
Inter-segment revenues	—	44,860	33,205	(78,065)	—
Total revenues	276,652	58,753	52,023	(78,065)	309,363
Operating income (loss)	(133,625)	33,200	1,848	(4,852)	(103,429)
Other income (expense)	(131,119)	(2)	37	—	(131,084)
Income (loss) before income taxes	$(264,744)	$33,198	$1,885	$(4,852)	$(234,513)
At June 30, 2017:					
Property, plant and equipment, net	$5,567,347	$495,112	$41,228	$(172,673)	$5,931,014
Total assets[(1)]	5,881,351	504,119	48,924	(172,673)	6,261,721
At December 31, 2016:					
Property, plant and equipment, net	$5,620,558	$424,197	$47,189	$(172,377)	$5,919,567
Total assets[(1)]	5,868,747	431,095	51,167	(172,377)	6,178,632

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(1) Intercompany receivables (payables) for all segments were reclassified to capital contributions from (distributions to) parent and not included in total assets.

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13. Commitments and Contingencies

The Company has various contractual obligations in the normal course of its operations. As of June 30, 2017, there have been no material changes to the Company’s future commitments as disclosed in Note 16 in the Company’s 2016 Annual Report.

Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. 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.

Mirada litigation. On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, “Mirada”) filed a lawsuit against Oasis, OPNA and OMS, seeking monetary damages in excess of $100 million, declaratory relief, attorneys’ fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by the Company in Wild Basin. Specifically, Mirada asserts that the Company has breached certain agreements by: (1) failing to allow Mirada to participate in the Company’s midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada’s consent prior to drilling more than one well at a time in Wild Basin; and (4) by overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that the Company be removed as operator in Wild Basin at Mirada’s election and that Mirada be allowed to elect a new operator; certain agreements apply to the Company and Mirada and Wild Basin with respect to this dispute; the Company be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and the Company not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada’s consent. Mirada also seeks a declaratory judgment with respect to the Company’s current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in the Company’s Wild Basin midstream operations, consisting of produced water disposal, crude oil gathering and gas gathering and processing; that, upon Mirada’s election to participate, Mirada is obligated to pay its proportionate costs of the Company’s midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the “Contract Area.”

On June 30, 2017, Mirada amended its original petition to add a claim that the Company has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

The Company believes that Mirada’s claims are without merit, that the Company has complied with its obligations under the applicable agreements and that some of Mirada’s claims are grounded in agreements which do not apply to the Company. The Company filed an answer denying Mirada’s claims on April 21, 2017, and intends to vigorously defend against Mirada’s claims. Discovery is ongoing, and trial is currently scheduled for July 2018. However, the Company cannot predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Company’s interests, or if the Company were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Company’s business, results of operations and financial condition. Such an adverse determination could materially impact the Company’s ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in the Company’s midstream operations could materially reduce the interests of the Company in their current assets and future midstream opportunities and related revenues in Wild Basin.

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14. Condensed Consolidating Financial Information

The Notes (see Note 7 – 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

	June 30, 2017			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets				
Cash and cash equivalents	$178	$11,262	$—	$11,440
Accounts receivable, net	—	218,302	—	218,302
Accounts receivable - affiliates	187,496	33,709	(221,205)	—
Inventory	—	17,942	—	17,942
Prepaid expenses	664	9,946	—	10,610
Derivative instruments	—	31,851	—	31,851
Other current assets	3	59	—	62
Total current assets	188,341	323,071	(221,205)	290,207
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	7,488,075	—	7,488,075
Other property and equipment	—	695,592	—	695,592
Less: accumulated depreciation, depletion, amortization and impairment	—	(2,252,653)	—	(2,252,653)
Total property, plant and equipment, net	—	5,931,014	—	5,931,014
Investments in and advances to subsidiaries	4,545,805	—	(4,545,805)	—
Derivative instruments	—	11,834	—	11,834
Deferred income taxes	257,652	—	(257,652)	—
Long-term inventory	—	8,762	—	8,762
Other assets	—	19,904	—	19,904
Total assets	$4,991,798	$6,294,585	$(5,024,662)	$6,261,721
LIABILITIES AND STOCKHOLDERS’ EQUITY				
Current liabilities				
Accounts payable	$—	$12,257	$—	$12,257
Accounts payable - affiliates	33,709	187,496	(221,205)	—
Revenues and production taxes payable	—	143,715	—	143,715
Accrued liabilities	—	139,766	—	139,766
Accrued interest payable	38,796	332	—	39,128
Advances from joint interest partners	—	5,816	—	5,816
Total current liabilities	72,505	489,382	(221,205)	340,682
Long-term debt	1,941,683	418,000	—	2,359,683
Deferred income taxes	—	784,833	(257,652)	527,181
Asset retirement obligations	—	51,059	—	51,059
Other liabilities	—	5,506	—	5,506
Total liabilities	2,014,188	1,748,780	(478,857)	3,284,111
Stockholders’ equity				
Capital contributions from affiliates	—	3,395,528	(3,395,528)	—
Common stock, $0.01 par value: 450,000,000 shares authorized; 238,642,598 shares issued and 237,410,395 shares outstanding	2,345	—	—	2,345
Treasury stock, at cost: 1,232,203 shares	(21,401)	—	—	(21,401)
Additional paid-in-capital	2,362,084	8,743	(8,743)	2,362,084

Retained earnings	634,582	1,141,534	(1,141,534)	634,582
Total stockholders’ equity	2,977,610	4,545,805	(4,545,805)	2,977,610
Total liabilities and stockholders’ equity	$4,991,798	$6,294,585	$(5,024,662)	$6,261,721

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Condensed Consolidating Balance Sheet

	December 31, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
ASSETS				
Current assets				
Cash and cash equivalents	$166	$11,060	$—	$11,226
Accounts receivable, net	—	204,335	—	204,335
Accounts receivable - affiliates	252,000	27,619	(279,619)	—
Inventory	—	10,648	—	10,648
Prepaid expenses	275	7,348	—	7,623
Derivative instruments	—	362	—	362
Other current assets	—	4,355	—	4,355
Total current assets	252,441	265,727	(279,619)	238,549
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	7,296,568	—	7,296,568
Other property and equipment	—	618,790	—	618,790
Less: accumulated depreciation, depletion, amortization and impairment	—	(1,995,791)	—	(1,995,791)
Total property, plant and equipment, net	—	5,919,567	—	5,919,567
Investments in and advances to subsidiaries	4,451,192	—	(4,451,192)	—
Derivative instruments	—	—	—	—
Deferred income taxes	220,058	—	(220,058)	—
Other assets	—	20,516	—	20,516
Total assets	$4,923,691	$6,205,810	$(4,950,869)	$6,178,632
LIABILITIES AND STOCKHOLDERS’ EQUITY				
Current liabilities				
Accounts payable	$—	$4,645	$—	$4,645
Accounts payable - affiliates	27,619	252,000	(279,619)	—
Revenues and production taxes payable	—	139,737	—	139,737
Accrued liabilities	12	119,161	—	119,173
Accrued interest payable	38,689	315	—	39,004
Derivative instruments	—	60,469	—	60,469
Advances from joint interest partners	—	7,597	—	7,597
Other current liabilities	—	10,490	—	10,490
Total current liabilities	66,320	594,414	(279,619)	381,115
Long-term debt	1,934,214	363,000	—	2,297,214
Deferred income taxes	—	733,587	(220,058)	513,529
Asset retirement obligations	—	48,985	—	48,985
Derivative instruments	—	11,714	—	11,714
Other liabilities	—	2,918	—	2,918
Total liabilities	2,000,534	1,754,618	(499,677)	3,255,475
Stockholders’ equity				
Capital contributions from affiliates	—	3,388,893	(3,388,893)	—
Common stock, $0.01 par value: 450,000,000 shares authorized; 237,201,064 shares issued and 236,344,172 shares outstanding	2,331	—	—	2,331

Treasury stock, at cost: 856,892 shares	(15,950)	—	—	(15,950)
Additional paid-in-capital	2,345,271	8,743	(8,743)	2,345,271
Retained earnings	591,505	1,053,556	(1,053,556)	591,505
Total stockholders’ equity	2,923,157	4,451,192	(4,451,192)	2,923,157
Total liabilities and stockholders’ equity	$4,923,691	$6,205,810	$(4,950,869)	$6,178,632

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Condensed Consolidating Statement of Operations

	Three Months Ended June 30, 2017			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 218,633	$ —	$ 218,633
Bulk oil sales	—	8,091	—	8,091
Midstream revenues	—	15,566	—	15,566
Well services revenues	—	11,801	—	11,801
Total revenues	—	254,091	—	254,091
Operating expenses				
Lease operating expenses	—	44,665	—	44,665
Midstream operating expenses	—	3,263	—	3,263
Well services operating expenses	—	8,088	—	8,088
Marketing, transportation and gathering expenses	—	12,039	—	12,039
Bulk oil purchases	—	7,980	—	7,980
Production taxes	—	18,971	—	18,971
Depreciation, depletion and amortization	—	125,291	—	125,291
Exploration expenses	—	1,667	—	1,667
Impairment	—	3,200	—	3,200
General and administrative expenses	7,534	16,014	—	23,548
Total operating expenses	7,534	241,178	—	248,712
Operating income (loss)	(7,534)	12,913	—	5,379
Other income (expense)				
Equity in earnings of subsidiaries	38,875	—	(38,875)	—
Net gain on derivative instruments	—	50,532	—	50,532
Interest expense, net of capitalized interest	(33,006)	(3,832)	—	(36,838)
Other expense	—	(166)	—	(166)
Total other income	5,869	46,534	(38,875)	13,528
Income (loss) before income taxes	(1,665)	59,447	(38,875)	18,907
Income tax benefit (expense)	18,233	(20,572)	—	(2,339)
Net income	$ 16,568	$ 38,875	$ (38,875)	$ 16,568

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Condensed Consolidating Statement of Operations

	Three Months Ended June 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 159,337	$ —	$ 159,337
Midstream revenues	—	6,910	—	6,910
Well services revenues	—	12,833	—	12,833
Total revenues	—	179,080	—	179,080
Operating expenses				
Lease operating expenses	—	31,523	—	31,523
Midstream operating expenses	—	1,740	—	1,740
Well services operating expenses	—	7,135	—	7,135
Marketing, transportation and gathering expenses	—	6,491	—	6,491
Production taxes	—	14,367	—	14,367
Depreciation, depletion and amortization	—	122,488	—	122,488
Exploration expenses	—	340	—	340
Impairment	—	23	—	23
General and administrative expenses	6,395	15,481	—	21,876
Total operating expenses	6,395	199,588	—	205,983
Loss on sale of properties	—	(1,311)	—	(1,311)
Operating loss	(6,395)	(21,819)	—	(28,214)
Other income (expense)				
Equity in loss of subsidiaries	(71,987)	—	71,987	—
Net loss on derivative instruments	—	(90,846)	—	(90,846)
Interest expense, net of capitalized interest	(33,190)	(1,789)	—	(34,979)
Gain on extinguishment of debt	11,642	—	—	11,642
Other expense	—	(32)	—	(32)
Total other expense	(93,535)	(92,667)	71,987	(114,215)
Loss before income taxes	(99,930)	(114,486)	71,987	(142,429)
Income tax benefit	9,999	42,499	—	52,498
Net loss	$(89,931)	$ (71,987)	$ 71,987	$ (89,931)

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Condensed Consolidating Statement of Operations

	Six Months Ended June 30, 2017			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 455,885	$ —	$ 455,885
Bulk oil sales	—	35,722	—	35,722
Midstream revenues	—	30,172	—	30,172
Well services revenues	—	17,428	—	17,428
Total revenues	—	539,207	—	539,207
Operating expenses				
Lease operating expenses	—	88,537	—	88,537
Midstream operating expenses	—	6,590	—	6,590
Well services operating expenses	—	11,990	—	11,990
Marketing, transportation and gathering expenses	—	22,990	—	22,990
Bulk oil purchases	—	35,982	—	35,982
Production taxes	—	39,270	—	39,270
Depreciation, depletion and amortization	—	251,957	—	251,957
Exploration expenses	—	3,156	—	3,156
Impairment	—	5,882	—	5,882
General and administrative expenses	14,599	32,783	—	47,382
Total operating expenses	14,599	499,137	—	513,736
Operating income (loss)	(14,599)	40,070	—	25,471
Other income (expense)				
Equity in earnings of subsidiaries	87,978	—	(87,978)	—
Net gain on derivative instruments	—	106,607	—	106,607
Interest expense, net of capitalized interest	(65,857)	(7,302)	—	(73,159)
Other expense	—	(150)	—	(150)
Total other income	22,121	99,155	(87,978)	33,298
Income before income taxes	7,522	139,225	(87,978)	58,769
Income tax benefit (expense)	32,871	(51,247)	—	(18,376)
Net income	$40,393	$ 87,978	$ (87,978)	$ 40,393

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Condensed Consolidating Statement of Operations

	Six Months Ended June 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 276,652	$ —	$ 276,652
Midstream revenues	—	13,893	—	13,893
Well services revenues	—	18,818	—	18,818
Total revenues	—	309,363	—	309,363
Operating expenses				
Lease operating expenses	—	62,587	—	62,587
Midstream operating expenses	—	3,478	—	3,478
Well services operating expenses	—	9,786	—	9,786
Marketing, transportation and gathering expenses	—	15,043	—	15,043
Production taxes	—	25,120	—	25,120
Depreciation, depletion and amortization	—	244,937	—	244,937
Exploration expenses	—	703	—	703
Impairment	—	3,585	—	3,585
General and administrative expenses	13,846	32,396	—	46,242
Total operating expenses	13,846	397,635	—	411,481
Loss on sale of properties	—	(1,311)	—	(1,311)
Operating loss	(13,846)	(89,583)	—	(103,429)
Other income (expense)				
Equity in loss of subsidiaries	(109,314)	—	109,314	—
Net loss on derivative instruments	—	(76,471)	—	(76,471)
Interest expense, net of capitalized interest	(68,022)	(5,696)	—	(73,718)
Gain on extinguishment of debt	18,658	—	—	18,658
Other income	43	404	—	447
Total other expense	(158,635)	(81,763)	109,314	(131,084)
Loss before income taxes	(172,481)	(171,346)	109,314	(234,513)
Income tax benefit	18,095	62,032	—	80,127
Net loss	$(154,386)	$(109,314)	$ 109,314	$(154,386)

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Condensed Consolidating Statement of Cash Flows

	Six Months Ended June 30, 2017			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Cash flows from operating activities:				
Net income	$40,393	$ 87,978	$ (87,978)	$ 40,393
Adjustments to reconcile net income to net cash provided by operating activities:				
Equity in earnings of subsidiaries	(87,978)	—	87,978	—
Depreciation, depletion and amortization	—	251,957	—	251,957
Impairment	—	5,882	—	5,882
Deferred income taxes	(32,871)	51,247	—	18,376
Derivative instruments	—	(106,607)	—	(106,607)
Stock-based compensation expenses	13,395	428	—	13,823
Deferred financing costs amortization and other	7,470	1,401	—	8,871
Working capital and other changes:				
Change in accounts receivable	64,504	(19,833)	(58,414)	(13,743)
Change in inventory	—	(1,007)	—	(1,007)
Change in prepaid expenses	(389)	125	—	(264)
Change in other current assets	(3)	283	—	280
Change in long-term inventory and other assets	—	(8,768)	—	(8,768)
Change in accounts payable, interest payable and accrued liabilities	6,185	(53,441)	58,414	11,158
Change in other current liabilities	—	(10,490)	—	(10,490)
Net cash provided by operating activities	10,706	199,155	—	209,861
Cash flows from investing activities:				
Capital expenditures	—	(252,461)	—	(252,461)
Proceeds from sale of properties	—	4,000	—	4,000
Derivative settlements	—	(8,899)	—	(8,899)
Advances from joint interest partners	—	(1,781)	—	(1,781)
Net cash used in investing activities	—	(259,141)	—	(259,141)
Cash flows from financing activities:				
Proceeds from revolving credit facility	—	484,000	—	484,000
Principal payments on revolving credit facility	—	(429,000)	—	(429,000)
Purchases of treasury stock	(5,451)	—	—	(5,451)
Investment in / capital contributions from subsidiaries	(5,188)	5,188	—	—
Other	(55)	—	—	(55)
Net cash provided by (used in) financing activities	(10,694)	60,188	—	49,494
Increase in cash and cash equivalents	12	202	—	214
Cash and cash equivalents at beginning of period	166	11,060	—	11,226
Cash and cash equivalents at end of period	$178	$ 11,262	$ —	$ 11,440

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Condensed Consolidating Statement of Cash Flows

	Six Months Ended June 30, 2016			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Cash flows from operating activities:				
Net loss	$(154,386)	$(109,314)	$ 109,314	$(154,386)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:				
Equity in loss of subsidiaries	109,314	—	(109,314)	—
Depreciation, depletion and amortization	—	244,937	—	244,937
Gain on extinguishment of debt	(18,658)	—	—	(18,658)
Loss on sale of properties	—	1,311	—	1,311
Impairment	—	3,585	—	3,585
Deferred income taxes	(18,095)	(62,032)	—	(80,127)
Derivative instruments	—	76,471	—	76,471
Stock-based compensation expenses	12,624	355	—	12,979
Deferred financing costs amortization and other	3,360	3,192	—	6,552
Working capital and other changes:				
Change in accounts receivable	(85)	53,068	(48,686)	4,297
Change in inventory	—	2,054	—	2,054
Change in prepaid expenses	278	1,145	—	1,423
Change in other current assets	—	(114)	—	(114)
Change in long-term inventory and other assets	100	—	—	100
Change in accounts payable, interest payable and accrued liabilities	(50,462)	(16,258)	48,686	(18,034)
Change in other current liabilities	—	9,001	—	9,001
Change in other liabilities	—	10	—	10
Net cash provided by (used in) operating activities	(116,010)	207,411	—	91,401
Cash flows from investing activities:				
Capital expenditures	—	(231,341)	—	(231,341)
Proceeds from sale of properties	—	11,679	—	11,679
Costs related to sale of properties	—	(310)	—	(310)
Derivative settlements	—	103,790	—	103,790
Advances from joint interest partners	—	769	—	769
Net cash used in investing activities	—	(115,413)	—	(115,413)
Cash flows from financing activities:				
Proceeds from revolving credit facility	—	359,000	—	359,000
Principal payments on revolving credit facility	—	(462,000)	—	(462,000)
Repurchase of senior unsecured notes	(56,925)	—	—	(56,925)
Deferred financing costs	—	(751)	—	(751)
Proceeds from sale of common stock	182,953	—	—	182,953
Purchases of treasury stock	(1,520)	—	—	(1,520)
Investment in / capital contributions from subsidiaries	(9,190)	9,190	—	—
Net cash provided by (used in) financing activities	115,318	(94,561)	—	20,757
Decrease in cash and cash equivalents	(692)	(2,563)	—	(3,255)
Cash and cash equivalents at beginning of period	777	8,953	—	9,730
Cash and cash equivalents at end of period	$85	$6,390	$ —	$6,475

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15. Subsequent Events

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

Derivative instruments. In July and August 2017, the Company entered into new swaps and two-way costless collar options for crude oil which settle based on WTI. The commodity contracts included a total notional amount of 244,000 barrels with a weighted average floor price of $49.43 per barrel which settle in 2017, 2,915,000 barrels with a weighted average floor price of $48.59 per barrel which settle in 2018, and 248,000 barrels with a weighted average floor price of $48.49 per barrel which settle in 2019. These derivative instruments do not qualify for or were not designated as hedging instruments for accounting purposes.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with "Management's Discussion and Analysis of Financial Condition and Results of Operations" contained in our Annual Report on Form 10-K for the year ended December 31, 2016 ("2016 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 Part II, Item 1A. "Risk Factors" in our 2016 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 midstream company;
- owning and operating a well services company;
- infrastructure for salt water gathering and disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston Basin and other regions in the United States;
- property acquisitions, including our recent acquisition of oil and gas properties in the Williston Basin;
- 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;

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- developments in oil-producing and natural gas-producing countries;
- technology;
- uncertainty regarding future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

All forward-looking statements speak only as of the date of this Quarterly Report on Form 10-Q. We disclaim any obligation to update or revise these statements unless required by securities law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Quarterly Report on Form 10-Q are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, 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 midstream services business through Oasis Midstream Services LLC ("OMS") and a well services business through Oasis Well Services LLC ("OWS"), 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 OMS and OWS 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. 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. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives.

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.

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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 and natural gas sales contracts with purchasers who have access to 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 significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. Currently, 90% of our gross operated oil production and substantially all of our gross operated natural gas production are connected to these gathering systems, and our crude oil price differentials have improved to less than $3.00 per barrel primarily due to the additional takeaway capacity of the Dakota Access Pipeline of over 450,000 barrels per day.

Highlights:

- We produced 61,943 barrels of oil equivalent per day ("Boepd") in the second quarter of 2017;
- We completed and placed on production 15 gross (10.8 net) operated wells in the Williston Basin in the second quarter of 2017 and ended the quarter with 81 gross operated wells waiting on completion;
- Total capital expenditures were $173.0 million and $282.8 million for the three and six months ended June 30, 2017, respectively;
- At June 30, 2017, we had $11.4 million of cash and cash equivalents and had total liquidity of $733.4 million, including the availability under our revolving credit facility;
- Net cash provided by operating activities was $102.1 million for the three months ended June 30, 2017. Adjusted EBITDA, a non-GAAP financial measure, was $141.3 million for the three months ended June 30, 2017. 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 bulk oil sales are derived from the sale of oil purchased through our marketing activities primarily for blending. Our midstream revenues are primarily derived from salt water pipeline transport, salt water disposal, natural gas gathering and processing, fresh water sales and crude oil gathering and transportation. Our well services revenues are derived from well services, product sales and equipment rentals. Substantially all of our midstream revenues and well services revenues are from services for third-party working interest owners in OPNA's operated wells. Intercompany revenues for work performed by OMS and OWS for OPNA's working interests are eliminated in consolidation and are therefore not included in midstream and well services revenues.

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Change	2017	2016	Change
Operating results (in thousands):						
Revenues						
Oil	$194,005	$152,900	$41,105	$402,599	$264,106	$138,493
Natural gas	24,628	6,437	18,191	53,286	12,546	40,740
Bulk oil sales	8,091	—	8,091	35,722	—	35,722
Midstream	15,566	6,910	8,656	30,172	13,893	16,279
Well services	11,801	12,833	(1,032)	17,428	18,818	(1,390)
Total revenues	$254,091	$179,080	$75,011	$539,207	$309,363	$229,844
Production data:						
Oil (MBbls)	4,349	3,747	602	8,785	7,617	1,168
Natural gas (MMcf)	7,725	4,549	3,176	15,237	8,802	6,435
Oil equivalents (MBoe)	5,637	4,505	1,132	11,324	9,084	2,240
Average daily production (Boe per day)	61,943	49,507	12,436	62,564	49,911	12,653
Average sales prices:						
Oil, without derivative settlements (per Bbl)	$44.61	$40.81	$3.80	$45.83	$34.67	$11.16
Oil, with derivative settlements (per Bbl)(1)	42.56	48.94	(6.38)	40.72	48.30	(7.58)
Natural gas (per Mcf)(2)	3.19	1.42	1.77	3.50	1.43	2.07

(1) Realized prices include gains or losses on cash settlements for commodity derivatives, which do not qualify for or 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 June 30, 2017 as compared to three months ended June 30, 2016

Oil and gas revenues. Our oil and gas revenues increased $59.3 million, or 37%, to $218.6 million during the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. The higher oil and natural gas production amounts sold increased revenues by $37.0 million coupled with a $22.3 million increase due to higher oil and natural gas sales prices during the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. Average oil sales prices, without derivative settlements, increased by $3.80 per barrel to an average of $44.61 per barrel, and average natural gas sales prices, which includes the value for natural gas and natural gas liquids, increased by $1.77 per Mcf to an average of $3.19 per Mcf for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. Average daily production sold increased by 12,436 Boe per day to 61,943 Boe per day during the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. The increase in average daily production sold was primarily a result of our acquisition completed on December 1, 2016 of approximately 55,000 net acres in the Williston Basin (the “Williston Basin Acquisition”).

Bulk oil sales. During the three months ended June 30, 2017, bulk oil sales were $8.1 million, which represents the sale of crude oil purchased primarily for blending at our crude oil terminal that began in late 2016. There were no bulk oil sales during the three months ended June 30, 2016.

Midstream revenues. Midstream revenues increased $8.7 million to $15.6 million during the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. This increase was driven by a $7.3 million increase primarily related to higher natural gas volumes gathered, compressed and processed coupled with a $2.2 million increase related to higher oil volumes gathered, stabilized and transported as a result of the start up of our natural gas processing plant and our oil gathering system in the second half of 2016, respectively. These increases were offset by a decrease of $0.6 million related to lower salt water disposal revenues.

Well services revenues. Our well services revenues decreased by 8% to $11.8 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016, primarily due to OWS completing OPNA wells with a lower average third-party working interest during the three months ended June 30, 2017, offset by an increase in well completion product sales.

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Six months ended June 30, 2017 as compared to six months ended June 30, 2016

Oil and gas revenues. Our oil and gas revenues increased $179.2 million, or 65%, to $455.9 million during the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. The higher oil and natural gas sales prices increased revenues by $103.2 million coupled with a $76.0 million increase due to higher oil and natural gas production amounts sold during the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. Average oil sales prices, without derivative settlements, increased by $11.16 per barrel to an average of $45.83 per barrel, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, increased by $2.07 per Mcf to an average of $3.50 per Mcf for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. Average daily production sold increased by 12,653 Boe per day to 62,564 Boe per day during the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. The increase in average daily production sold was primarily a result of the Williston Basin Acquisition completed on December 1, 2016 of approximately 55,000 net acres.

Bulk oil sales. During the six months ended June 30, 2017, bulk oil sales were $35.7 million, which represents the sale of crude oil purchased primarily for blending at our crude oil terminal that began in late 2016. There were no bulk oil sales during the six months ended June 30, 2016.

Midstream revenues. Midstream revenues increased $16.3 million to $30.2 million during the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. This increase was driven by a $13.6 million increase primarily related to higher natural gas volumes gathered, compressed and processed coupled with a $4.4 million increase related to higher oil volumes gathered, stabilized and transported as a result of the start up of our natural gas processing plant and our oil gathering system in the second half of 2016, respectively. These increases were offset by a decrease of $1.0 million related to salt water disposal revenues coupled with a $0.8 million decrease related to lower freshwater sales.

Well services revenues. In response to the low commodity price environment, we decreased the pace of our well completions and reduced OWS to one fracturing fleet during the first quarter of 2016. Our well services revenues decreased by 7% to $17.4 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, primarily due to a decrease in well completion activity, offset by an increase in well completion product sales.

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Expenses and other income

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

	Three Months Ended June 30,			Six Months Ended June 30,		
	2017	2016	Change	2017	2016	Change
	(In thousands, except per Boe of production)					
Operating expenses:						
Lease operating expenses	$44,665	$31,523	$13,142	$88,537	$62,587	$25,950
Midstream operating expenses	3,263	1,740	1,523	6,590	3,478	3,112
Well services operating expenses	8,088	7,135	953	11,990	9,786	2,204
Marketing, transportation and gathering expenses	12,039	6,491	5,548	22,990	15,043	7,947
Bulk oil purchases	7,980	—	7,980	35,982	—	35,982
Production taxes	18,971	14,367	4,604	39,270	25,120	14,150
Depreciation, depletion and amortization	125,291	122,488	2,803	251,957	244,937	7,020
Exploration expenses	1,667	340	1,327	3,156	703	2,453
Impairment	3,200	23	3,177	5,882	3,585	2,297
General and administrative expenses	23,548	21,876	1,672	47,382	46,242	1,140
Total operating expenses	248,712	205,983	42,729	513,736	411,481	102,255
Loss on sale of properties	—	(1,311)	1,311	—	(1,311)	1,311
Operating income (loss)	5,379	(28,214)	33,593	25,471	(103,429)	128,900
Other income (expense)						
Net gain (loss) on derivative instruments	50,532	(90,846)	141,378	106,607	(76,471)	183,078
Interest expense, net of capitalized interest	(36,838)	(34,979)	(1,859)	(73,159)	(73,718)	559
Gain on extinguishment of debt	—	11,642	(11,642)	—	18,658	(18,658)
Other income (expense)	(166)	(32)	(134)	(150)	447	(597)
Total other income (expense)	13,528	(114,215)	127,743	33,298	(131,084)	164,382
Income (loss) before income taxes	18,907	(142,429)	161,336	58,769	(234,513)	293,282
Income tax benefit (expense)	(2,339)	52,498	(54,837)	(18,376)	80,127	(98,503)
Net income (loss)	$16,568	$(89,931)	$106,499	$40,393	$(154,386)	$194,779
Costs and expenses (per Boe of production):						
Lease operating expenses	$7.92	$7.00	$0.92	$7.82	$6.89	$0.93
Marketing, transportation and gathering expenses	2.14	1.44	0.70	2.03	1.66	0.37
Production taxes	3.37	3.19	0.18	3.47	2.77	0.70
Depreciation, depletion and amortization	22.23	27.19	(4.96)	22.25	26.96	(4.71)
General and administrative expenses	4.18	4.86	(0.68)	4.18	5.09	(0.91)

Three months ended June 30, 2017 as compared to three months ended June 30, 2016

Lease operating expenses. Lease operating expenses increased $13.1 million to $44.7 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. The increase was primarily due to higher costs associated with operating an increased number of producing wells as a result of our well completions and the Williston Basin Acquisition coupled with an increase in workover costs during the three months ended June 30, 2017. Lease operating expenses increased from $7.00 per Boe for the three months ended June 30, 2016 to $7.92 per Boe for the three months ended June 30, 2017 primarily due to the higher aforementioned costs.

Midstream operating expenses. Midstream operating expenses represent operating expenses incurred by OMS associated with volumes for third-party working interest owners. The $1.5 million increase for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016 was primarily related to the start up of our natural gas processing plant and our oil gathering system during 2016, partially offset by a decrease in salt water disposal expenses.

Well services operating expenses. Well services operating expenses represent operating expenses incurred by OWS for third-party working interest owners’ share of completion services. The $1.0 million increase for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016 was primarily attributable to well

completion product sales, offset by lower well completion activity and decreased maintenance and trucking costs.
Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $5.5 million, or $0.70 per Boe, for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016,

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which was primarily attributable to higher oil gathering and transportation expenses related to additional well connections on OMS infrastructure and the start up of our natural gas processing plant and our oil gathering system, respectively, in the second half of 2016 coupled with the start up of the Dakota Access Pipeline during the three months ended June 30, 2017. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $2.17 during the three months ended June 30, 2017 as compared to $1.55 during the three months ended June 30, 2016.

Bulk oil purchases. For the three months ended June 30, 2017, we incurred $8.0 million of bulk oil purchase costs primarily related to blending. We did not incur similar charges during the three months ended June 30, 2016.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 8.7% and 9.0% for the three months ended June 30, 2017 and 2016, respectively. The production tax rate decreased period over period primarily due to a lower oil production mix. North Dakota's natural gas production tax is $0.0601 per Mcf.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $2.8 million to $125.3 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. This increase in DD&A expense for the three months ended June 30, 2017 was a result of production increases from our wells completed during the three months ended June 30, 2017 coupled with the Williston Basin Acquisition, offset by a decrease in the DD&A rate to $22.23 per Boe for the three months ended June 30, 2017 as compared to $27.19 per Boe for the three months ended June 30, 2016. The decrease in the DD&A rate was primarily due to lower well costs and higher recoverable reserves.

Impairment. As a result of periodic assessments of our unproved properties not held-by-production, we recorded an impairment loss on our unproved oil and natural gas properties of $3.2 million for the three months ended June 30, 2017 related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. For the three months ended June 30, 2016, we recorded an impairment loss on our unproved oil and natural gas properties of $23,000 due to leases that expired in the period. No impairment charges of proved oil and gas or other properties were recorded for the three months ended June 30, 2017 and 2016.

General and administrative expenses ("G&A"). Our G&A increased $1.7 million to $23.5 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. E&P and OMS G&A increased $2.1 million and $1.0 million, respectively, for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016. The increase in E&P and OMS was primarily due to increased employee compensation expenses as a result of organizational growth due to increased activity and the start up of our natural gas processing plant in the third quarter of 2016. OWS G&A decreased $1.4 million for the three months ended June 30, 2017 as compared to the three months ended June 30, 2016 primarily due to OWS completing OPNA wells with a lower average third-party working interest and decreased employee compensation and rental expenses.

Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil changes, we incurred a $50.5 million net gain on derivative instruments, including net cash settlement payments of $0.9 million, for the three months ended June 30, 2017, and a $90.8 million net loss on derivative instruments, including net cash settlement receipts of $30.5 million for the three months ended June 30, 2016. 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 increased $1.8 million from $35.0 million for the three months ended June 30, 2016 to $36.8 million for the three months ended June 30, 2017 primarily due to interest expense related to our senior unsecured convertible notes issued in September 2016, which includes debt discount amortization, and our revolving credit facility coupled with a decrease in capitalized interest due to lower costs for work in progress assets as a result of the completion of our natural gas processing plant in the third quarter of 2016. This increase was offset by the repurchase of an aggregate principal amount of $447.0 million of outstanding senior unsecured notes in 2016, which resulted in a $7.0 million decrease in interest costs. For the three months ended June 30, 2017 and 2016, the weighted average debt outstanding under our revolving credit facility was $422.1 million and $82.7 million, respectively. The weighted average interest rate incurred on the outstanding borrowings under our revolving credit facility was 2.8% and 2.0% for the three months ended June 30, 2017 and 2016, respectively. Interest capitalized during the three months ended June 30, 2017 and 2016 was $2.8 million and $4.8 million, respectively.

Gain on extinguishment of debt. For the three months ended June 30, 2017, we did not repurchase any portion of our outstanding senior unsecured notes. During the three months ended June 30, 2016, we repurchased an aggregate principal amount of $46.8 million of our outstanding senior unsecured notes for an aggregate cost of $34.6 million, including accrued interest and fees. For the three months ended June 30, 2016, we recognized a pre-tax gain related to the repurchase of $11.6 million, which included unamortized deferred financing costs write-offs of $0.5 million.
Income taxes. The income tax expense for the three months ended June 30, 2017 was recorded at 12.4% of pre-tax income, and the income tax benefit for the three months ended June 30, 2016 was recorded at 36.9% of pre-tax loss. The effective tax rate for the three months ended June 30, 2017 was 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 and a forecasted annual pre-tax loss for 2017, while the effective tax rate for the three months ended June 30, 2016 was 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 pre-tax loss for the period. The permanent differences were primarily between amounts expensed for book purposes versus the amounts deductible for income tax purposes related to compensation.

Six months ended June 30, 2017 as compared to six months ended June 30, 2016

Lease operating expenses. Lease operating expenses increased $26.0 million to $88.5 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. The increase was primarily due to higher costs associated with operating an increased number of producing wells as a result of our well completions and the Williston Basin Acquisition coupled with an increase in workover costs during the six months ended June 30, 2017. Lease operating expenses increased from $6.89 per Boe for the six months ended June 30, 2016 to $7.82 per Boe for the six months ended June 30, 2017 primarily due to the higher aforementioned costs.

Midstream operating expenses. Midstream operating expenses represent operating expenses incurred by OMS associated with volumes for third-party working interest owners. The $3.1 million increase for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 was primarily related to the start up of our natural gas processing plant and our oil gathering system during 2016, partially offset by a decrease in fresh water purchases.

Well services operating expenses. Well services operating expenses represent operating expenses incurred by OWS for third-party working interest owners' share of completion services. The $2.2 million increase for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 was primarily attributable to increased well completion product sales coupled with increased maintenance and trucking costs, offset by lower well completion activity.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $7.9 million, or $0.37 per Boe, for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016, which was primarily attributable to an increase in natural gas gathering and processing expenses coupled with higher oil gathering and transportation expenses related to additional well connections on OMS infrastructure and the start up of our natural gas processing plant and our oil gathering system, respectively, in the second half of 2016. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $1.97 during the six months ended June 30, 2017 as compared to $1.58 during the six months ended June 30, 2016.

Bulk oil purchases. For the six months ended June 30, 2017, we incurred $36.0 million of bulk oil purchase costs primarily related to blending. We did not incur similar charges during the six months ended June 30, 2016.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 8.6% and 9.1% for the six months ended June 30, 2017 and 2016, respectively. The production tax rate decreased period over period primarily due to a lower oil production mix. North Dakota's natural gas production tax is $0.0601 per Mcf.

Depreciation, depletion and amortization. DD&A expense increased $7.0 million to $252.0 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. This increase in DD&A expense for the six months ended June 30, 2017 was a result of production increases from our wells completed during the six months ended June 30, 2017 coupled with the Williston Basin Acquisition, offset by a decrease in the DD&A rate to $22.25 per Boe for the six months ended June 30, 2017 as compared to $26.96 per Boe for the six months ended June 30, 2016. The decrease in the DD&A rate was primarily due to lower well costs and higher recoverable reserves.

Impairment. As a result of periodic assessments of our unproved properties not held-by-production, we recorded an impairment loss on our unproved oil and natural gas properties of $5.9 million for the six months ended June 30, 2017 related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. For the six months ended June 30, 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 or other properties were recorded for the six months ended June 30, 2017.

General and administrative expenses. Our G&A increased $1.1 million to $47.4 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016. E&P G&A was $40.0 million and $38.8 million for the six months ended June 30, 2017 and 2016, respectively. The $1.1 million increase in E&P G&A was primarily due to increased compensation expenses due to an increase in employee headcount, partially offset by severance expenses during the first quarter of 2016. OMS G&A increased $1.7 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 primarily due to increased employee compensation as a result of organizational growth within this segment due to the start up of our natural gas processing plant in the third quarter of 2016. OWS G&A decreased $1.7 million for the six months ended June 30, 2017 as compared to the six months ended June 30, 2016 primarily due to lower compensation expenses due to severance expenses paid in 2016.

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Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $106.6 million net gain on derivative instruments, including net cash settlement payments of $8.9 million, for the six months ended June 30, 2017, and a $76.5 million net loss on derivative instruments, including net cash settlement receipts of $103.8 million, for the six months ended June 30, 2016. 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 decreased $0.5 million from $73.7 million for the six months ended June 30, 2016 to $73.2 million for the six months ended June 30, 2017 primarily due to the repurchase of an aggregate principal amount of $447.0 million of outstanding senior unsecured notes in 2016, which resulted in a $15.1 million decrease in interest costs. This decrease was offset by interest expense related to our senior unsecured convertible notes issued in September 2016, which includes debt discount amortization, and our revolving credit facility coupled with a decrease in capitalized interest due to lower costs for work in progress assets as a result of the completion of our natural gas processing plant in the third quarter of 2016. For the six months ended June 30, 2017 and 2016, the weighted average debt outstanding under our revolving credit facility was $411.5 million and $94.8 million, respectively. The weighted average interest rate incurred on the outstanding borrowings under our revolving credit facility was 2.7% and 1.9% for the six months ended June 30, 2017 and 2016, respectively. Interest capitalized during the six months ended June 30, 2017 and 2016 was $5.6 million and $9.3 million, respectively.

Gain on extinguishment of debt. For the six months ended June 30, 2017, we did not repurchase any portion of our outstanding senior unsecured notes. During the six months ended June 30, 2016, we repurchased an aggregate principal amount of $76.6 million of our outstanding senior unsecured notes for an aggregate cost of $56.9 million, including accrued interest and fees. For the six months ended June 30, 2016, we recognized a pre-tax gain related to the repurchase of $18.7 million, which included unamortized deferred financing costs write-offs of $1.0 million.

Income taxes. The income tax expense for the six months ended June 30, 2017 was recorded at 31.3% of pre-tax income, and the income tax benefit for the six months ended June 30, 2016 was recorded at 34.2% of pre-tax loss. The effective tax rate for the six months ended June 30, 2017 was 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 and a forecasted annual pre-tax loss for 2017, while the effective tax rate for the six months ended June 30, 2016 was 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 pre-tax loss for the period. The permanent differences were primarily between amounts expensed for book purposes versus the amounts deductible for income tax purposes related to compensation.

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 and midstream infrastructure, payment of operating and general and administrative costs, interest payments on outstanding debt and repurchases of our senior unsecured notes. 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 six months ended June 30, 2017 and 2016 are presented below:

	Six Months Ended June 30,	
	2017	2016
	(In thousands)	
Net cash provided by operating activities	$209,861	$91,401
Net cash used in investing activities	(259,141)	(115,413)
Net cash provided by financing activities	49,494	20,757
Increase (decrease) in cash and cash equivalents	$214	$(3,255)

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 and natural gas prices on a portion of our production, thereby mitigating our exposure to oil and natural gas price declines, but these transactions may also limit our cash flow in periods of rising oil and natural gas prices. 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 provided by operating activities was $209.9 million and $91.4 million for the six months ended June 30, 2017 and 2016, respectively. The change in cash flows from operating activities for the period ended June 30, 2017 as compared to 2016 was primarily the result of higher realized oil and natural gas sales prices.

Working capital. Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and acquisitions, and the impact of our outstanding derivative instruments. We had a working capital deficit of $50.5 million at June 30, 2017 primarily due to increases in our current liabilities, including accrued liabilities for drilling and development costs. As of June 30, 2017, we had $733.4 million of liquidity available, including $11.4 million in cash and cash equivalents and $722.0 million of unused borrowing base committed capacity available under our revolving credit facility. At June 30, 2016, we had a working capital deficit of $139.8 million.

Cash flows used in investing activities

Net cash used in investing activities was $259.1 million and $115.4 million during the six months ended June 30, 2017 and 2016, respectively. Net cash used in investing activities during the six months ended June 30, 2017 was primarily attributable to $252.5 million in capital expenditures primarily for drilling and development costs. Net cash used in investing activities during the six months ended June 30, 2016 was primarily attributable to $231.3 million in capital expenditures primarily for drilling and development costs, partially offset by $103.8 million of derivative settlements received as a result of lower commodity prices.

Our capital expenditures are summarized in the following table:

	Six Months Ended June 30, 2017 (In thousands)
Capital expenditures:	
E&P	$ 191,602
OMS	66,921
OWS	268
Other capital expenditures(1)	23,979
Total capital expenditures(2)	$ 282,770

(1) Other capital expenditures include asset acquisitions, primarily related to midstream assets, of $17.2 million and other items, such as administrative capital and capitalized interest. See Note 6 to our unaudited condensed consolidated financial statements for a description of our midstream assets acquisition.

(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 2017 capital expenditure budget is $605.0 million, which includes $410.0 million of drilling and completion capital expenditures (including expected savings from services provided by OMS and OWS), $110.0 million for midstream infrastructure and $85.0 million of other capital expenditures, including other E&P capital, capitalized interest, OWS and administrative capital.

While we have budgeted $605.0 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. Furthermore, if we acquire additional acreage, our capital expenditures may be higher than budgeted. We believe that cash on hand, including cash flows from operating activities and availability under our revolving credit facility should be sufficient to fund our 2017 capital expenditure budget and to meet our future obligations. However, because the operated wells funded by our 2017 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 further be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil prices decline for an extended period of time, 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 $49.5 million and $20.8 million for the six months ended June 30, 2017 and 2016, respectively. For the six months ended June 30, 2017, cash provided by financing activities was primarily due to proceeds from the borrowings under our revolving credit facility, partially offset by principal payments on our revolving credit facility coupled with purchases of treasury stock for shares that employees surrendered back to us to pay tax withholdings upon the vesting of restricted stock awards. Net cash provided by financing activities during the six months ended June 30, 2016 was primarily due to proceeds from borrowings under our revolving credit facility and net proceeds from the issuance of our common stock, partially offset by principal payments on our revolving credit facility and the repurchase of a portion of our outstanding senior unsecured notes.

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 June 30, 2017. 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 7.25% senior unsecured notes due February 2019 (the “2019 Notes”) are retired or refinanced 90 days prior to their maturity date. On April 10, 2017, the lenders under the Credit Facility (the “Lenders”) completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2017, resulting in an increase in the borrowing base from $1,150.0 million to $1,600.0 million; however, we elected to limit the Lenders’ aggregate commitment to $1,150.0 million. The next redetermination of the borrowing base is scheduled for October 1, 2017.

At June 30, 2017, we had $418.0 million of borrowings at a weighted average interest rate of 3.0% and $10.0 million of outstanding letters of credit issued under the Credit Facility, resulting in an unused borrowing base committed capacity of $722.0 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;
- 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 at June 30, 2017. At June 30, 2017, our consolidated EBITDAX was $527.2 million and our consolidated Interest Expense was $138.2 million, resulting in a ratio of 3.8 as compared to a minimum required ratio of 2.5. In addition, as of June 30, 2017, our consolidated current assets and consolidated current liabilities (as described above) were $980.4 million and $340.7 million, respectively, resulting in a Current Ratio of 2.9 as compared to a minimum required ratio of 1.0. Given the possible fluctuation in commodity prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

Senior unsecured notes. At June 30, 2017, our long-term debt includes outstanding obligations of $1,753.0 million for senior unsecured notes (the “Senior Notes”), including $54.3 million of the 2019 Notes, $395.5 million of the 6.5%

senior unsecured notes due November 2021 (the “2021 Notes”), $937.1 million of the 6.875% senior unsecured notes due March 2022 (the “2022 Notes”) and $366.1 million of the 6.875% senior unsecured notes due January 2023 (the “2023 Notes”).

Prior to certain dates, we have the option to redeem some or all of the Senior 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 2019 Notes are currently redeemable for cash at a redemption price equal to par plus accrued and unpaid interest to the redemption date. We may from time to time seek to retire or purchase our outstanding Senior 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 indentures governing the Senior 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 Senior Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Senior unsecured convertible notes. In September 2016, we issued \$300.0 million of 2.625% Senior Convertible Notes due September 2023. We have the option to settle conversions of these notes with cash, shares of common stock or a combination of cash and common stock at our election. Our intent is to settle the principal amount of the Senior Convertible Notes in cash upon conversion. Prior to March 15, 2023, the Senior Convertible Notes will be convertible only under the following circumstances: (i) during any calendar quarter (and only during such calendar quarter), if the last reported sale price of our common stock for at least 20 trading days (whether or not consecutive) during the period of 30 consecutive trading days ending on the last trading day of the immediately preceding calendar quarter is greater than or equal to 130% of the conversion price on each applicable trading day; (ii) during the five business day period after any five consecutive trading day period (the "measurement period") in which the trading price per \$1,000 principal amount of the Senior Convertible Notes for each trading day of the measurement period is less than 98% of the product of the last reported sale price of our common stock and the conversion rate on each such trading day; or (iii) upon the occurrence of specified corporate events. On or after March 15, 2023, the Senior Convertible Notes will be convertible at any time until the second scheduled trading day immediately preceding the September 15, 2023 maturity date. The Senior Convertible Notes will be convertible at an initial conversion rate of 76.3650 shares of our common stock per \$1,000 principal amount of the notes, which is equivalent to an initial conversion price of approximately \$13.10. The conversion rate will be subject to adjustment in some events but will not be adjusted for any accrued and unpaid interest. In addition, following certain corporate events that occur prior to the maturity date or a notice of redemption, we will increase the conversion rate for a holder who elects to convert the Senior Convertible Notes in connection with such corporate event or redemption in certain circumstances. As of June 30, 2017, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met.

Interest on the Senior Notes and the Senior Convertible Notes (collectively, the "Notes") is payable semi-annually in arrears. The Notes are guaranteed on a senior unsecured basis by our material subsidiaries.

Non-GAAP Financial Measures

Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) Per Share 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 interest expense, net income (loss), operating income (loss), net cash provided by (used in) operating activities, earnings (loss) per share or any other measures prepared under GAAP. Because Cash Interest, Adjusted EBITDA, Free Cash Flow, Adjusted Net Income (Loss) and Adjusted Diluted Earnings (Loss) Per Share 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.

Cash Interest

We define Cash Interest as interest expense plus capitalized interest less amortization and write-offs of deferred financing costs and debt discounts included in interest expense. Cash Interest is not a measure of interest expense as determined by GAAP. Management believes that the presentation of Cash Interest provides useful additional information to investors and analysts for assessing the interest charges incurred on our debt, excluding non-cash amortization, and our ability to maintain compliance with our debt covenants.

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The following table presents a reconciliation of the GAAP financial measure of interest expense to the non-GAAP financial measure of Cash Interest for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Interest expense	$36,838	$34,979	$73,159	$73,718
Capitalized interest	2,816	4,835	5,636	9,303
Amortization of deferred financing costs	(1,709)	(2,030)	(3,399)	(5,947)
Amortization of debt discount	(2,480)	—	(4,835)	—
Cash Interest	$35,465	$37,784	$70,561	$77,074

Adjusted EBITDA and Free Cash Flow

We define Adjusted EBITDA as earnings (loss) before interest expense, income taxes, DD&A, exploration expenses and other similar non-cash or nonrecurring 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, financial performance and our ability to generate cash from our business operations without regard to our financing methods or capital structure coupled with our ability to maintain compliance with our debt covenants.

We define Free Cash Flow as Adjusted EBITDA less Cash Interest and capital expenditures, excluding capitalized interest. Free Cash Flow is not a measure of net income (loss) or cash flows as determined by GAAP. Management believes that the presentation of Free Cash Flow provides useful additional information to investors and analysts for assessing our financial performance as compared to our peers and our ability to generate cash from our business operations after interest and capital spending. In addition, Free Cash Flow excludes changes in operating assets and liabilities that relate to the timing of cash receipts and disbursements, which we may not control, and changes in operating assets and liabilities may not relate to the period in which the operating activities occurred.

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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 measures of Adjusted EBITDA and Free Cash Flow for the periods presented:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Net income (loss)	$16,568	$(89,931)	$40,393	$(154,386)
Loss on sale of properties	—	1,311	—	1,311
Gain on extinguishment of debt	—	(11,642)	—	(18,658)
Net (gain) loss on derivative instruments	(50,532)	90,846	(106,607)	76,471
Derivative settlements[1]	(939)	30,477	(8,899)	103,790
Interest expense, net of capitalized interest	36,838	34,979	73,159	73,718
Depreciation, depletion and amortization	125,291	122,488	251,957	244,937
Impairment	3,200	23	5,882	3,585
Exploration expenses	1,667	340	3,156	703
Stock-based compensation expenses	7,115	6,249	13,823	12,979
Income tax (benefit) expense	2,339	(52,498)	18,376	(80,127)
Other non-cash adjustments	(213)	(484)	699	723
Adjusted EBITDA	141,334	132,158	291,939	265,046
Cash interest	(35,465)	(37,784)	(70,561)	(77,074)
Capital expenditures[2]	(172,975)	(131,288)	(282,770)	(219,243)
Capitalized interest	2,816	4,835	5,636	9,303
Free Cash Flow	$(64,290)	$(32,079)	$(55,756)	$(21,968)
Net cash provided by operating activities	$102,062	$137,452	$209,861	$91,401
Derivative settlements[1]	(939)	30,477	(8,899)	103,790
Interest expense, net of capitalized interest	36,838	34,979	73,159	73,718
Exploration expenses	1,667	340	3,156	703
Deferred financing costs amortization and other	(3,931)	(1,486)	(8,871)	(6,552)
Changes in working capital	5,850	(69,120)	22,834	1,263
Other non-cash adjustments	(213)	(484)	699	723
Adjusted EBITDA	141,334	132,158	291,939	265,046
Cash interest	(35,465)	(37,784)	(70,561)	(77,074)
Capital expenditures[2]	(172,975)	(131,288)	(282,770)	(219,243)
Capitalized interest	2,816	4,835	5,636	9,303
Free Cash Flow	$(64,290)	$(32,079)	$(55,756)	$(21,968)

(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) 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.

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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:

Exploration and Production

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Income (loss) before income taxes	$(3,900)	$(158,978)	$16,836	$(264,744)
Loss on sale of properties	—	1,669	—	1,669
Gain on extinguishment of debt	—	(11,642)	—	(18,658)
Net (gain) loss on derivative instruments	(50,532)	90,846	(106,607)	76,471
Derivative settlements[1]	(939)	30,477	(8,899)	103,790
Interest expense, net of capitalized interest	36,838	34,979	73,159	73,718
Depreciation, depletion and amortization	122,785	120,039	247,193	240,881
Impairment	3,200	23	5,882	1,154
Exploration expenses	1,667	340	3,156	703
Stock-based compensation expenses	6,897	6,077	13,395	12,625
Other non-cash adjustments	(213)	(484)	699	723
Adjusted EBITDA	$115,803	$113,346	$244,814	$228,332

(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.

Midstream Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Income before income taxes	$23,106	$18,040	$43,867	$33,198
Gain on sale of properties	—	(358)	—	(358)
Depreciation, depletion and amortization	3,753	1,732	7,211	3,415
Impairment	—	—	—	2,431
Stock-based compensation expenses	365	224	713	443
Adjusted EBITDA	$27,224	$19,638	$51,791	$39,129

Well Services

	Three Months Ended June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands)			
Income (loss) before income taxes	$1,950	$(2,142)	$(1,637)	$1,885
Depreciation, depletion and amortization	3,057	3,895	6,222	8,127
Stock-based compensation expenses	338	235	734	899
Adjusted EBITDA	$5,345	$1,988	$5,319	$10,911

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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 items, including non-cash changes in the fair value of derivative instruments, impairment and other similar non-cash charges, or non-recurring items 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 in comparison to our peers. This measure is more comparable to earnings estimates provided by securities analysts, and charges or amounts excluded cannot be reasonably estimated and is excluded from guidance provided by the Company.

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 June 30,		Six Months Ended June 30,	
	2017	2016	2017	2016
	(In thousands, except per share data)			
Net income (loss)	$16,568	$(89,931)	$40,393	$(154,386)
Loss on sale of properties	—	1,311	—	1,311
Gain on extinguishment of debt	—	(11,642)	—	(18,658)
Net (gain) loss on derivative instruments	(50,532)	90,846	(106,607)	76,471
Derivative settlements(1)	(939)	30,477	(8,899)	103,790
Impairment	3,200	23	5,882	3,585
Amortization of deferred financing costs	1,709	2,030	3,399	5,947
Amortization of debt discount	2,480	—	4,835	—
Other non-cash adjustments	(213)	(484)	699	723
Tax impact(2)	16,575	(42,075)	37,679	(64,731)
Adjusted Net Loss	$(11,152)	$(19,445)	$(22,619)	$(45,948)
Diluted earnings (loss) per share	$0.07	$(0.51)	$0.17	$(0.91)
Loss on sale of properties	—	0.01	—	0.01
Gain on extinguishment of debt	—	(0.07)	—	(0.11)
Net (gain) loss on derivative instruments	(0.22)	0.51	(0.45)	0.45
Derivative settlements(1)	—	0.17	(0.04)	0.61
Impairment	0.01	—	0.02	0.02
Amortization of deferred financing costs	0.01	0.01	0.01	0.03
Amortization of debt discount	0.01	—	0.02	—
Tax impact(2)	0.07	(0.23)	0.17	(0.37)
Non-GAAP Diluted Loss Per Share	$(0.05)	$(0.11)	$(0.10)	$(0.27)
Diluted weighted average shares outstanding	234,917	176,984	236,281	169,953
Effective tax rate applicable to adjustment items	37.4 %	37.4 %	37.4 %	37.4 %

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(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.

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Critical Accounting Policies and Estimates

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2016 Annual Report. See Note 2 to our unaudited condensed consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

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 13 to our unaudited condensed consolidated financial statements for a description of our commitments and contingencies.

Item 3. — Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in prices for oil, natural gas and natural gas liquids, and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading. The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our 2016 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 and natural gas prices. Our crude oil and natural gas contracts will settle monthly based on the average WTI and the average NYMEX Henry Hub natural gas index price, respectively. As of June 30, 2017, we utilized swaps and two-way and three-way costless collar options to reduce the volatility of oil and natural gas prices on a significant portion of our future expected oil and natural gas production. A swap is a sold call and a purchased put established at the same price (both ceiling and floor), which we will receive for the volumes under contract. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be the NYMEX index price plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract.

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.

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The following is a summary of our derivative contracts as of June 30, 2017:

Commodity	Settlement Period	Derivative Instrument	Volumes		Weighted Average Prices Swap	Sub-Floor	Floor	Ceiling	Fair Value Asset (Liability) (In thousands)
Crude oil	2017	Swaps	3,843,000	Bbl	$49.83				$ 13,211
Crude oil	2017	Two-way collar	1,464,000	Bbl			$46.25	$54.37	3,122
Crude oil	2017	Three-way collar	1,098,000	Bbl		$ 31.67	$45.83	$59.94	1,816
Crude oil	2018	Swaps	5,508,000	Bbl	$51.95				20,746
Crude oil	2018	Two-way collar	582,000	Bbl			$48.40	$55.13	1,799
Crude oil	2018	Three-way collar	186,000	Bbl		$ 31.67	$45.83	$59.94	452
Crude oil	2019	Swaps	434,000	Bbl	$52.16				1,365
Crude oil	2019	Two-way collar	31,000	Bbl			$50.00	$55.70	104
Natural gas	2017	Swaps	3,680,000	MMBtu	$3.32				827
Natural gas	2018	Swaps	5,475,000	MMBtu	$3.04				243
									$ 43,685

A 10% increase in crude oil prices would decrease the fair value of our derivative position by approximately $53.3 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $54.7 million.

Interest rate risk. We had (i) $54.3 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum, (ii) $395.5 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum, (iii) $1,303.2 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum and (iv) $300.0 million of senior unsecured convertible notes as a fixed cash interest rate of 2.625% per annum outstanding at June 30, 2017. At June 30, 2017, we had $418.0 million of borrowings and $10.0 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 June 30, 2017, 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. No bad debt expense was recorded during the three and six months ended June 30, 2017. 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.

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.

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 the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $43.7 million at June 30, 2017.

As permitted under our investments policy, we may 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. This risk is managed by our investment policy including minimum credit ratings thresholds and maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers failing to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If an issuer fails to repay us at maturity from commercial paper proceeds, it could take a significant amount of time to recover a portion of or all of the assets originally invested. Our commercial paper balance was $36,000 at June 30, 2017.

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 June 30, 2017. 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 June 30, 2017.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended June 30, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II — OTHER INFORMATION

Item 1. — Legal Proceedings

Mirada litigation. On March 23, 2017, Mirada Energy, LLC, Mirada Wild Basin Holding Company, LLC and Mirada Energy Fund I, LLC (collectively, "Mirada") filed a lawsuit against Oasis Petroleum Inc., OPNA and OMS, seeking monetary damages in excess of $100 million, declaratory relief, attorneys' fees and costs (Mirada Energy, LLC, et al. v. Oasis Petroleum North America LLC, et al.; in the 334th Judicial District Court of Harris County, Texas; Case Number 2017-19911). Mirada asserts that it is a working interest owner in certain acreage owned and operated by the Company in Wild Basin. Specifically, Mirada asserts that the Company has breached certain agreements by: (1) failing to allow Mirada to participate in the Company's midstream operations in Wild Basin; (2) refusing to provide Mirada with information that Mirada contends is required under certain agreements and failing to provide information in a timely fashion; (3) failing to consult with Mirada and failing to obtain Mirada's consent prior to drilling more than one well at a time in Wild Basin; and (4) by overstating the estimated costs of proposed well operations in Wild Basin. Mirada seeks a declaratory judgment that the Company be removed as operator in Wild Basin at Mirada's election and that Mirada be allowed to elect a new operator; certain agreements apply to the Company and Mirada and Wild Basin with respect to this dispute; the Company be required to provide all information within its possession regarding proposed or ongoing operations in Wild Basin; and the Company not be permitted to drill, or propose to drill, more than one well at a time in Wild Basin without obtaining Mirada's consent. Mirada also seeks a declaratory judgment with respect to the Company's current midstream operations in Wild Basin. Specifically, Mirada seeks a declaratory judgment that Mirada has a right to participate in the Company's Wild Basin midstream operations, consisting of produced water disposal, crude oil gathering and gas gathering and processing; that, upon Mirada's election to participate, Mirada is obligated to pay its proportionate costs of the Company's midstream operations in Wild Basin; and that Mirada would then be entitled to receive a share of revenues from the midstream operations and would not be charged any amount for its use of these facilities for production from the "Contract Area".

On June 30, 2017, Mirada amended its original petition to add a claim that the Company has breached certain agreements by charging Mirada for midstream services provided by its affiliates and to seek a declaratory judgment that Mirada is entitled to be paid its share of total proceeds from the sale of hydrocarbons received by OPNA or any affiliate of OPNA without deductions for midstream services provided by OPNA or its affiliates.

The Company believes that Mirada's claims are without merit, that the Company has complied with its obligations under the applicable agreements and that some of Mirada's claims are grounded in agreements which do not apply to the Company. The Company filed an answer denying Mirada's claims on April 21, 2017, and intends to vigorously defend against Mirada's claims. Discovery is ongoing, and trial is currently scheduled for July 2018. However, the Company cannot predict or guarantee the ultimate outcome or resolution of such matter. If such matter were to be determined adversely to the Company's interests, or if the Company were forced to settle such matter for a significant amount, such resolution or settlement could have a material adverse effect on the Company's business, results of operations and financial condition. Such an adverse determination could materially impact the Company's ability to operate its properties in Wild Basin or develop its identified drilling locations in Wild Basin on its current development schedule. A determination that Mirada has a right to participate in the Company's midstream operations could materially reduce the interests of the Company in their current assets and future midstream opportunities and related revenues in Wild Basin.

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 2016 Annual Report. There have been no material changes in our risk factors from those described in our 2016 Annual Report.

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

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

Issuer purchases of equity securities. The following table contains information about our acquisition of equity securities during the three months ended June 30, 2017:

Period	Total Number of Shares Exchanged[(1)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
April 1 - April 30, 2017	1,309	$ 13.36	—	—
May 1 - May 31, 2017	529	11.49	—	—
June 1 - June 30, 2017	797	9.88	—	—
Total	2,635	$ 11.93	—	—

(1) Represents 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.

Item 6. — Exhibits

Exhibit No.	Description of Exhibit
10.1	Eighth Amendment to Second Amended and Restated Credit Agreement dated as of April 10, 2017 among Oasis Petroleum North America LLC, as Borrower, the Guarantors party thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on April 13, 2017, and incorporated herein by reference).
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
101.INS (a)	XBRL Instance Document.
101.SCH (a)	XBRL Schema Document.
101.CAL (a)	XBRL Calculation Linkbase Document.
101.DEF (a)	XBRL Definition Linkbase Document.
101.LAB (a)	XBRL Labels Linkbase Document.
101.PRE (a)	XBRL Presentation Linkbase Document.

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

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SIGNATURES

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

OASIS PETROLEUM INC.

Date: August 3, 2017 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)