Oasis Petroleum Inc.
Form 10-Q
May 08, 2018
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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 March 31, 2018
or
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to
Commission file number: 1-34776
Oasis Petroleum Inc.
(Exact name of registrant as specified in its charter)

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨
Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 April 30, 2018: 317,308,489 shares.

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

	March 31, 2018	December 31, 2017
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$ 17,735	$ 16,720
Accounts receivable, net	370,978	363,580
Inventory	23,039	19,367
Prepaid expenses	5,954	7,631
Derivative instruments	—	344
Intangible assets, net	958	—
Other current assets	193	193
Total current assets	418,857	407,835
Property, plant and equipment		
Oil and gas properties (successful efforts method)	8,911,096	7,838,955
Other property and equipment	963,871	868,746
Less: accumulated depreciation, depletion, amortization and impairment	(2,688,361)	(2,534,215)
Total property, plant and equipment, net	7,186,606	6,173,486
Derivative instruments	—	9
Long-term inventory	12,506	12,200
Other assets	20,961	21,600
Total assets	$ 7,638,930	$ 6,615,130
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$ 16,127	$ 13,370
Revenues and production taxes payable	245,198	213,995
Accrued liabilities	233,422	236,480
Accrued interest payable	20,681	38,963
Derivative instruments	149,657	115,716
Advances from joint interest partners	4,888	4,916
Other current liabilities	40	40
Total current liabilities	670,013	623,480
Long-term debt	2,696,534	2,097,606
Deferred income taxes	306,749	305,921
Asset retirement obligations	51,955	48,511
Derivative instruments	19,699	19,851
Other liabilities	7,822	6,182
Total liabilities	3,752,772	3,101,551
Commitments and contingencies (Note 16)		
Stockholders' equity		
Common stock, $0.01 par value: 450,000,000 shares authorized; 319,384,813 shares issued and 317,363,008 shares outstanding at March 31, 2018 and 270,627,014 shares issued and 269,295,466 shares outstanding at December 31, 2017	3,154	2,668

Treasury stock, at cost: 2,021,805 and 1,331,548 shares at March 31, 2018 and December 31, 2017, respectively	(28,200)	(22,179)
Additional paid-in capital	3,055,003	2,677,217
Retained earnings	718,575	717,985
Oasis share of stockholders' equity	3,748,532	3,375,691
Non-controlling interests	137,626	137,888
Total stockholders' equity	3,886,158	3,513,579
Total liabilities and stockholders' equity	$ 7,638,930	$ 6,615,130

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 March 31,	
	2018	2017
	(In thousands, except per share data)	
Revenues		
Oil and gas revenues	$ 363,671	$ 237,252
Purchased oil and gas sales	18,037	27,631
Midstream revenues	27,922	14,606
Well services revenues	11,586	5,627
Total revenues	421,216	285,116
Operating expenses		
Lease operating expenses	44,781	43,872
Midstream operating expenses	7,985	3,327
Well services operating expenses	7,387	4,560
Marketing, transportation and gathering expenses	21,013	10,951
Purchased oil and gas expenses	17,998	28,002
Production taxes	31,000	20,299
Depreciation, depletion and amortization	149,265	126,666
Exploration expenses	769	1,489
Impairment	93	2,682
General and administrative expenses	27,940	23,176
Total operating expenses	308,231	265,024
Operating income	112,985	20,092
Other income (expense)		
Net gain (loss) on derivative instruments	(71,116)	56,075
Interest expense, net of capitalized interest	(37,146)	(36,321)
Other income (expense)	(183)	16
Total other income (expense)	(108,445)	19,770
Income before income taxes	4,540	39,862
Income tax expense	(828)	(16,037)
Net income including non-controlling interests	3,712	23,825
Less: Net income attributable to non-controlling interests	3,122	—
Net income attributable to Oasis	$ 590	$ 23,825
Earnings attributable to Oasis per share:		
Basic (Note 14)	$ 0.00	$ 0.10
Diluted (Note 14)	0.00	0.10
Weighted average shares outstanding:		
Basic (Note 14)	290,105	233,068
Diluted (Note 14)	291,738	237,900

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)

	Attributable to Oasis							
	Common Stock		Treasury Stock		Additional Paid-in Capital	Retained Earnings	Non-controlling Interests	Total Stockholders' Equity
	Shares	Amount	Shares	Amount				
	(In thousands)							
Balance at December 31, 2017	269,295	$2,668	1,332	$(22,179)	$2,677,217	$717,985	$ 137,888	$3,513,579
Permian Basin Acquisition issuance	46,000	460	—	—	370,760	—	—	371,220
Fees (2017 issuance of common stock)	—	—	—	—	(90)	—	—	(90)
Equity-based compensation	2,758	26	—	—	7,116	—	66	7,208
Distributions to non-controlling interest owners	—	—	—	—	—	—	(3,450)	(3,450)
Treasury stock - tax withholdings	(690)	—	690	(6,021)	—	—	—	(6,021)
Net income	—	—	—	—	—	590	3,122	3,712
Balance at March 31, 2018	317,363	$3,154	2,022	$(28,200)	$3,055,003	$718,575	$ 137,626	$3,886,158

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)

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Cash flows from operating activities:		
Net income including non-controlling interests	$3,712	$23,825
Adjustments to reconcile net income including non-controlling interests to net cash provided by operating activities:		
Depreciation, depletion and amortization	149,265	126,666
Impairment	93	2,682
Deferred income taxes	828	16,037
Derivative instruments	71,116	(56,075)
Equity-based compensation expenses	6,754	6,708
Deferred financing costs amortization and other	5,475	4,940
Working capital and other changes:		
Change in accounts receivable, net	(5,708)	(22,478)
Change in inventory	(3,672)	(3,679)
Change in prepaid expenses	492	282
Change in other current assets	—	(110)
Change in long-term inventory and other assets	(315)	(4)
Change in accounts payable, interest payable and accrued liabilities	(244)	6,060
Change in other current liabilities	—	2,945
Change in other liabilities	563	—
Net cash provided by operating activities	228,359	107,799
Cash flows from investing activities:		
Capital expenditures	(254,838)	(96,047)
Acquisitions	(520,728)	—
Derivative settlements	(36,974)	(7,960)
Advances from joint interest partners	(28)	(759)
Net cash used in investing activities	(812,568)	(104,766)
Cash flows from financing activities:		
Proceeds from Revolving Credit Facilities	1,470,000	246,000
Principal payments on Revolving Credit Facilities	(875,000)	(241,000)
Deferred financing costs	(215)	—
Purchases of treasury stock	(6,021)	(5,419)
Distributions to non-controlling interests	(3,450)	—
Other	(90)	(55)
Net cash provided by (used in) financing activities	585,224	(474)
Increase in cash and cash equivalents	1,015	2,559
Cash and cash equivalents:		
Beginning of period	16,720	11,226
End of period	$17,735	$13,785
Supplemental non-cash transactions:		
Change in accrued capital expenditures	$12,855	$8,396
Change in asset retirement obligations	3,453	787

Issuance of shares in connection with the Permian Basin Acquisition	371,220	—

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

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

1. Organization and Operations of the Company

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 onshore, unconventional oil and natural gas resources in the United States. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct the Company's exploration and production activities and own its proved and unproved oil and natural gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas regions of the Delaware Basin, respectively. The Company also operates a midstream services business through OMS Holdings 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. The midstream business is conducted by Oasis Midstream Partners LP ("OMP" or "Oasis Midstream"), which completed an initial public offering in September 2017. The Company owns the general partner and a majority of the outstanding units of OMP.

2. Summary of Significant Accounting Policies

Basis of Presentation

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, 2017 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 of the Company's financial position, 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, 2017 ("2017 Annual Report").

Consolidation. The accompanying condensed consolidated financial statements of the Company include the accounts of Oasis, the accounts of wholly-owned subsidiaries, and the accounts of OMP, which is considered a variable interest entity ("VIE") for which the Company is the primary beneficiary. All significant intercompany balances and transactions have been eliminated upon consolidation.

Consolidated VIE. The Company has determined that the partners with equity at risk in OMP lack the authority, through voting rights or similar rights, to direct the activities that most significantly impact OMP's economic performance. Therefore, as the limited partners of OMP do not have substantive kick-out or substantive participating rights over OMP GP LLC ("OMP GP"), the general partner to OMP, OMP is a VIE. Through the Company's ownership interest in OMP GP, the Company has the authority to direct the activities that most significantly affect economic performance and the right to receive benefits that could be potentially significant to OMP. Therefore, the Company is considered the primary beneficiary and consolidates OMP and records a non-controlling interest for the interest owned by the public as of March 31, 2018.

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. A substantial or extended decline in 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.

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Significant Accounting Policies

There have been no material changes to the Company's critical accounting policies and estimates from those disclosed in the 2017 Annual Report, other than as noted below.

Revenue recognition. In the first quarter of 2018, the Company adopted 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 was applied on a modified retrospective basis. The adoption of ASU 2014-09 did not result in a material impact to the Company's financial position, cash flows or results of operations. Enhanced disclosures in accordance with ASU 2014-09 have been provided in Note 3 – Revenue Recognition.

Financial instruments. In the first quarter of 2018, the Company adopted 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 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of March 31, 2018.

Statement of cash flows. In the first quarter of 2018, the Company adopted 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 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of March 31, 2018.

Income taxes. In the first quarter of 2018, the Company adopted Accounting Standards Update No. 2016-16, Intra-Entity Transfers of Assets Other Than Inventory ("ASU 2016-16"), to improve the accounting for the income tax consequences of intra-entity transfers of assets other than inventory. ASU 2016-16 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of March 31, 2018.

Business combinations. In the first quarter of 2018, the Company adopted 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 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of March 31, 2018.

Equity-based compensation. In the first quarter of 2018, the Company adopted 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. ASU 2017-09 was applied on a prospective basis and prior periods were not retrospectively adjusted. There was no material impact as a result of adoption as of March 31, 2018.

Recent Accounting Pronouncements

Leases. In February 2016, the Financial Accounting Standards Board ("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. In January 2018, the FASB issued Accounting Standards Update No. 2018-01, Land easement practical expedient for transition to Topic 842 ("ASU 2018-01"), which provides an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounting for as leases under Topic 840, Leases. The Company plans to elect this practical expedient and is currently evaluating the effect that adopting the new lease guidance will have on its financial position, cash flows or results of operations.

Income taxes. In March 2018, the FASB issued Accounting Standards Update No. 2018-05, Income Taxes (Topic 740) - Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118 (“ASU 2018-05”). The standard amends Accounting Standards Codification 740, Income Taxes (ASC 740) to provide guidance on accounting for the tax effects of the Tax Cuts and Jobs Act (the “Tax Act”) pursuant to Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act ("SAB 118"). The Company is currently evaluating the effect of the new tax guidance, but does not expect it to have a material impact on its financial position, cash flows or results of operations. See Note 12 – Income Taxes.

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3. Revenue Recognition

In May 2014, the FASB issued a new accounting standard related to revenue recognition, ASC 606 - Revenue from Contracts with Customers ("ASC 606"). This standard was effective in first quarter 2018 and the Company adopted the new standard using the modified retrospective method. The Company applied ASC 606 to all new contracts entered into after January 1, 2018 and all existing contracts for which all (or substantially all) of the revenue has not been recognized under legacy revenue guidance as of December 31, 2017. ASC 606 supersedes previous revenue recognition requirements in ASC 605 and includes a five-step revenue recognition model to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the Company expects to be entitled in exchange for those goods or services.

In accordance with the adoption of ASC 606, management evaluated its contracts with customers to apply the five-step revenue recognition model. The adoption of ASC 606 did not result in a material impact to the Company's financial position, cash flows or results of operations.

The unit of account in ASC 606 is a performance obligation, which is a promise in a contract to transfer to a customer either a distinct good or service (or bundle of goods or services) or a series of distinct goods or services provided over a period of time. ASC 606 requires that a contract's transaction price, which is the amount of consideration to which an entity expects to be entitled in exchange for transferring promised goods or services to a customer, is to be allocated to each performance obligation in the contract based on relative standalone selling prices and recognized as revenue when (point in time) or as (over time) the performance obligation is satisfied.

Exploration and production revenues

Our exploration and production revenues are derived from contracts for oil, natural gas and NGL sales, as described below. Generally, for the majority of these contracts: (i) each unit (barrel, mcf, gallon, etc.) of commodity product is a separate performance obligation, as our promise is to sell multiple distinct units of commodity product at a point in time; (ii) the transaction price principally consists of variable consideration, which amount is determinable each month end based on our right to invoice at month end for the value of commodity product sold to the customer that month; and (iii) the transaction price is allocated to each performance obligation based on the commodity product's standalone selling price and recognized as revenue upon delivery of the commodity product, which is the point in time when the customer obtains control of the commodity product and our performance obligation is satisfied. The sales of oil, natural gas and NGLs as presented on the Company's Condensed Consolidated Statements of Operations represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling oil, natural gas and NGLs on behalf of royalty owners or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. The Company's contracts with customers typically require payments for oil, natural gas and NGL sales within 30 days following the calendar month of delivery.

Oil sales. The Company sells a substantial majority of its oil through bulk sales at delivery points on crude oil gathering systems or directly at the wellhead to a variety of customers under short-term contracts that include a specified quantity of crude oil to be delivered and sold to the customer at a specified delivery point. The customer pays a market-based transaction price, which incorporates differentials that include, but are not limited to, transportation costs and adjustments for product quality.

Natural gas sales. The Company's natural gas sales consist of unprocessed gas sales and residue gas sales. Unprocessed gas is sold at delivery points at or near the wellhead under percentage of proceeds contracts, in which the customer pays a transaction price based on its sale of the bifurcated NGLs and residue gas, less any associated fees. Revenue is recorded on a net basis, with processing fees deducted within revenue rather than as a separate expense line item, as title and control transfer at the delivery point. Residue gas is sold from the tailgate of the Company's gas processing plant located in Wild Basin or transported and sold at other downstream sales points, and the customer pays a transaction price based on a market indexed per-unit rate for the quantities sold.

NGL sales. NGLs are sold from the Company's gas processing plant complex located in Wild Basin or trucked and sold at other downstream locations, and the customer pays a transaction price based on a market indexed per-unit rate

for the quantities sold.

Prior period performance obligations. For sales of oil, purchased oil, natural gas, purchased gas and NGLs, the Company records revenue in the month production is delivered to the purchaser. However, settlement statements and payment may not be received for 30 to 90 days after the date production is delivered, and as a result, the Company is required to estimate the amount of production that was delivered to the purchaser and the price that will be received for the sale of the product. The Company records the differences between estimates and the actual amounts received for product sales once payment is received from the purchaser. Such differences have historically not been significant. The Company uses knowledge of its properties, its properties' historical performance, spot market prices and other factors as the basis for these estimates. For the three months

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ended March 31, 2018, revenue recognized related to performance obligations satisfied in prior reporting periods was not material.

Revenues associated with contracts with customers for oil, natural gas and NGL sales were as follows for the three months ended March 31, 2018 and 2017:

Exploration and Production Revenues

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Oil revenues	$323,386	$208,595
Purchased oil sales	17,989	27,630
Natural gas revenues	26,961	19,535
Purchased gas sales	49	—
NGL revenues	13,323	9,124
Total exploration and production revenues	$381,708	$264,884

Midstream revenues

Crude oil and natural gas revenues. The Company is party to certain contracts for gas gathering, compression, processing and gas lift services, as well as crude oil gathering, stabilization, blending, storage and transportation. Under these customer contracts, the Company provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the Company's performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Water revenues. The Company is also party to certain contracts with customers for water services, which includes produced and flowback water gathering and disposal services and freshwater distribution services. Under its customer contracts for produced and flowback water gathering and disposal services, the Company provides daily integrated midstream services on a stand ready basis over a period of time, which represents a single performance obligation since the customer simultaneously receives and consumes the benefits of these services on a daily basis. Satisfaction of the Company's performance obligation is measured as each day of service is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized based upon the transaction price at month-end under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Under its customer contracts for freshwater distribution services, the Company supplies and distributes freshwater to its customers for hydraulic fracturing and production optimization. Management has determined these contracts contain multiple distinct performance obligations since each freshwater barrel is not dependent nor highly interrelated with other barrels. Revenue associated with freshwater distribution services is recognized at a point-in-time based upon the transaction price when title, control and risk of loss transfers to the customer, which occurs at the delivery point. Payments are due from customers 30 days after receipt of invoice.

Revenues associated with contracts with customers for midstream services were as follows for the three months ended March 31, 2018 and 2017:

Midstream Revenues[(1)]

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Crude oil and natural gas revenues	$18,029	$8,551

Water revenues	9,893	6,055
Total midstream revenues	$27,922	$14,606

(1) Represents midstream revenues excluding all intercompany revenues for work performed by the midstream services business segment for Oasis's working interests that are eliminated in consolidation and are therefore not included in midstream services revenues.

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Well services revenues

Hydraulic fracturing service revenues. Hydraulic fracturing revenue is recognized upon the completion of each hydraulic fracturing of a well. These services are composed of various components, such as personnel, equipment and hydraulic fracturing materials, but management determined that each component is not distinct, as it cannot be used on its own or together with a resource readily available to the customer. Revenue is recognized when the performance obligations of hydraulic fracturing a well in its totality are completed; generally, this is over a period of time due to all work being performed for a customer occurring on the customer's property, where the customer has control over the work in process as it is being performed. In addition, the Company's assets being used to perform the obligations have no alternative use at the time of performance and the Company has the right to payment for performance to date. Payments from customers are generally received by the Company within one month after the month in which services are provided. In addition, revenue from product sales to third parties is generated when OPNA requests that third-party hydraulic fracturing companies hydraulic fracture OPNA's wells. Although the labor is provided by the third-party hydraulic fracturing company, the materials (e.g., sand, chemicals, etc.) used in the hydraulic fracturing of the wells are provided by OWS. The third-party hydraulic fracturing company or OPNA pays OWS for the materials delivered to the wells. Revenue is recognized once the performance obligations to transfer hydraulic fracturing materials are completed.

Equipment rental revenues. Equipment rental revenue is generated when OPNA or a third-party hydraulic fracturing company rents equipment from OWS. This equipment is used in the preparation stage of hydraulic fracturing services or after the hydraulic fracturing services have been completed. Equipment rental revenues are calculated based on the equipment's daily rental rate and the number of days that the equipment was rented by the customer. OWS's performance obligation is satisfied when the entire rental period is completed. Equipment rental revenues are recognized over a period of time due to the customer simultaneously receiving and consuming the benefits of the rental equipment provided by OWS on a daily basis. Satisfaction of the Company's performance obligation is measured as each day of rental period is completed, which directly corresponds with its right to consideration from the customer. Revenues associated with these contracts are recognized at the time of invoicing for the entire rental period under the right to invoice practical expedient. Payments from customers are generally received by the Company within one month after the month in which services are provided.

Revenues associated with contracts with customers for hydraulic fracturing services and equipment rental sales were as follows for the three months ended March 31, 2018 and 2017:

Well Services Revenues[1]

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Hydraulic fracturing service revenues	$10,426	$5,156
Equipment rental revenues	1,160	471
Total well services revenues	$11,586	$5,627

(1) Represents well services revenues excluding all intercompany revenues for work performed by the well services business segment for Oasis's working interests that are eliminated in consolidation and are therefore not included in well services revenues.

Contract balances

Under the Company's customer contracts, invoicing occurs once the Company's performance obligations have been satisfied, at which point payment is unconditional. Accordingly, the Company's contracts do not give rise to contract assets or liabilities under ASC 606.

Performance obligations

The majority of the Company's sales are short-term in nature with a contract term of one year or less. For those contracts, the Company utilized the practical expedient in ASC 606-10-50-14 that exempts the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company utilized the practical expedient in ASC 606-10-50-14(A) which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these sales contracts, each unit of product generally represents a separate performance obligation; therefore future

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volumes are wholly unsatisfied and disclosure of the transaction price allocated to remaining performance obligations is not required. Under the midstream services contracts, each unit of service represents a separate performance obligation and therefore performance obligations in respect of future services are wholly unsatisfied.

4. Inventory

Crude oil inventory includes oil in tanks. 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.

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:

	March 31, 2018	December 31, 2017
	(In thousands)	
Inventory		
Crude oil inventory	$10,390	$ 10,427
Equipment and materials	12,649	8,940
Total inventory	$23,039	$ 19,367
Long-term inventory		
Linefill in third-party pipelines	$12,506	$ 12,200
Long-term inventory	$12,506	$ 12,200
Total	$35,545	$ 31,567

5. Accounts Receivable, Net

The following table sets forth the Company's accounts receivable, net:

	March 31, 2018	December 31, 2017
	(In thousands)	
Accounts receivable, net		
Trade accounts	$235,480	$ 233,660
Joint interest accounts	91,817	73,588
Other accounts	45,254	57,905
Total	372,551	365,153
Allowance for doubtful accounts	(1,573)	(1,573)
Total accounts receivable, net	$370,978	$ 363,580

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6. Fair Value Measurements

In accordance with the FASB's authoritative guidance on fair value measurements, the Company's financial assets and liabilities are measured at fair value on a recurring basis. The Company'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.

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Financial Assets and Liabilities

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

	Fair value at March 31, 2018			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$142	$—	$—	$142
Total assets	$142	$—	$—	$142
Liabilities:				
Commodity derivative instruments (see Note 7)	$—	$169,356	$—	$169,356
Total liabilities	$—	$169,356	$—	$169,356

	Fair value at December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$142	$—	$—	$142
Commodity derivative instruments (see Note 7)	—	353	—	353
Total assets	$142	$353	$—	$495
Liabilities:				
Commodity derivative instruments (see Note 7)	$—	$135,567	$—	$135,567
Total liabilities	$—	$135,567	$—	$135,567

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 March 31, 2018 and December 31, 2017. 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 liability by $3.1 million at March 31, 2018 and by $2.8 million

at December 31, 2017.

There were no transfers between fair value levels during the three months ended March 31, 2018 and December 31, 2017.

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7. 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 March 31, 2018, 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 6 – Fair Value Measurements). The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in fair value are recognized in the other income (expense) section of the Company's Condensed Consolidated 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 March 31, 2018, 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	2018	Swaps	11,029,000	Bbl	$51.92				$ (125,062)
Crude oil	2018	Two-way collar	825,000	Bbl			$48.67	$53.07	(8,649)
Crude oil	2019	Swaps	5,489,000	Bbl	$53.05				(32,612)
Crude oil	2019	Two-way collar	93,000	Bbl			$48.67	$53.07	(812)
Crude oil	2019	Three-way collar	2,004,000	Bbl		$ 40.00	$50.00	$65.99	(2,217)
Crude oil	2020	Swaps	403,000	Bbl	$53.47				(1,261)
Crude oil	2020	Three-way collar	186,000	Bbl		$ 40.00	$50.00	$65.99	(113)
Natural gas	2018	Swaps	6,325,000	MMbtu	$3.05				1,369
									$ (169,357)

In April and May 2018, the Company entered into new swaps and two-way and three-way costless collar options for crude oil and natural gas with weighted average floor prices of $56.79 per barrel and $2.93 per MMBtu, respectively. The commodity contracts included total notional amounts of 826,000 barrels, 1,641,000 barrels and 124,000 barrels which settle in 2018, 2019 and 2020, respectively, based on WTI and 1,104,000 MMBtu and 540,000 MMBtu which settle in 2018 and 2019, respectively, based on Henry Hub. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

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 March 31, 2018	2017
	(In thousands)	
Net gain (loss) on derivative instruments	$(71,116)	$56,075

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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.

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

		March 31, 2018		
Commodity	Balance Sheet Location	Gross Recognized Liabilities	Gross Amount Offset	Net Recognized Fair Value Liabilities
		(In thousands)		
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$149,657	$—	$ 149,657
Commodity contracts	Derivative instruments — non-current liabilities	25,214	(5,515)	19,699
Total derivatives liabilities		$174,871	$(5,515)	$ 169,356

		December 31, 2017		
Commodity	Balance Sheet Location	Gross Recognized Assets/Liabilities	Gross Amount Offset	Net Recognized Fair Value Assets/Liabilities
		(In thousands)		
Derivatives assets:				
Commodity contracts	Derivative instruments — current assets	$344	$—	$ 344
Commodity contracts	Derivative instruments — non-current assets	9	—	9
Total derivatives assets		$353	$—	$ 353
Derivatives liabilities:				
Commodity contracts	Derivative instruments — current liabilities	$117,629	$(1,913)	$ 115,716
Commodity contracts	Derivative instruments — non-current liabilities	20,035	(184)	19,851
Total derivatives liabilities		$137,664	$(2,097)	$ 135,567

8. Property, Plant and Equipment

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

	March 31, 2018	December 31, 2017
	(In thousands)	
Proved oil and gas properties[(1)]	$7,484,783	$7,058,782
Less: Accumulated depreciation, depletion, amortization and impairment	(2,538,739)	(2,395,153)
Proved oil and gas properties, net	4,946,044	4,663,629
Unproved oil and gas properties	1,426,313	780,173
Other property and equipment	963,871	868,746
Less: Accumulated depreciation	(149,622)	(139,062)
Other property and equipment, net	814,249	729,684
Total property, plant and equipment, net	$7,186,606	$6,173,486

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $42.7 million and $39.9 million at March 31, 2018 and December 31, 2017, respectively.

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9. Acquisition

Permian Basin Acquisition. On February 14, 2018, the Company acquired from Forge Energy, LLC ("Forge Energy") approximately 22,000 net acres in the Delaware Basin (the "Permian Basin Acquisition") for aggregate consideration consisting of approximately $549.8 million in cash and 46,000,000 shares of the Company's common stock, subject to customary post-closing adjustments (collectively, the "Purchase Price"). In connection with the closing of the Permian Basin Acquisition, the Company and Forge Energy entered into a Registration Rights Agreement that granted the equity holders of Forge Energy certain customary registration rights for the stock portion of the Purchase Price. The Company funded the cash portion of the Purchase Price with borrowings under a senior secured revolving line of credit among OPNA, as Borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "Oasis Credit Facility"), and proceeds from the Company's December 2017 issuance of its common stock.

The Permian Basin Acquisition represents the Company's initial entry into the Delaware Basin. The assets underlying the Permian Basin Acquisition are primarily located in the Bone Spring and Wolfcamp formations of the Delaware sub-basin, across Ward, Winkler, Loving and Reeves Counties, Texas.

The Permian Basin Acquisition qualified as a business combination. As such, the Company estimated the fair value of the assets acquired and liabilities assumed as of the February 14, 2018 acquisition date. The 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). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed under Note 6 — Fair Value Measurements. The Company recorded the assets acquired and liabilities assumed in the Permian Basin Acquisition at their estimated fair value of $921.0 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 Permian Basin Acquisition is considered a taxable transaction; therefore, no deferred tax amounts were recognized at the acquisition date as the tax basis of the assets acquired and liabilities assumed were also recorded at fair value.

The following table summarizes the consideration paid for the Company's acquisition and the fair value of the assets acquired and liabilities assumed as of the acquisition date. The purchase price allocation is preliminary and subject to adjustment, as the final closing statement will be completed in the third quarter of 2018.

	At February 14, 2018 (In thousands)
Consideration paid to Forge Energy:	
Cash	$ 549,770
Common stock: 46,000,000 shares issued	371,220
	$ 920,990
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Proved developed properties	$ 110,735
Proved undeveloped properties	167,170
Unproved lease acquisition costs	644,040
Inventory	293
Intangible assets	1,000
Asset retirement obligations	(2,248)
	$ 920,990

The results of operations for the Permian Basin Acquisition have been included in the Company's condensed consolidated financial statements since the February 14, 2018 closing date, including $11.5 million of total revenue

and $3.4 million of operating income for the three months ended March 31, 2018.

The Company also recorded a $1.0 million finite-lived intangible asset on the Company's Condensed Consolidated Balance Sheet for a non-compete agreement with a one-year life. Intangible assets are amortized on a straight-line basis over the useful life, and the Company includes the amortization in depreciation, depletion and amortization expenses on the Company's Condensed Consolidated Statements of Operations. For the three months ended March 31, 2018, amortization expense recognized for this non-compete agreement was approximately $42,000.

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Summarized below are the consolidated results of operations for the three months ended March 31, 2018, on an unaudited pro forma basis, as if the acquisition and related financing had occurred on January 1, 2017. The unaudited pro forma financial information was derived from the historical consolidated statements of operations of the Company and the statement of revenues and direct operating expenses for the Permian Basin Acquisition properties, which were derived from the historical accounting records of Forge Energy. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company's expected future results of operations.

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
	Unaudited	
Revenues	$426,733	$290,082
Net income attributable to Oasis	5,168	27,922
Net income attributable to Oasis per share:		
Basic	$0.02	$0.10
Diluted	0.02	0.10

10. Long-Term Debt

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

	March 31, 2018	December 31, 2017
	(In thousands)	
Oasis Credit Facility	$626,000	$70,000
OMP Credit Facility	117,000	78,000
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	(21,646)	(22,956)
Less: unamortized debt discount on senior unsecured convertible notes	(77,771)	(80,388)
Total long-term debt	$2,696,533	$2,097,606

The carrying amount of the Company's long-term debt reported in the Condensed Consolidated Balance Sheet at March 31, 2018 was $2,696.5 million, which included $2,053.0 million of senior unsecured notes, reductions for the unamortized debt discount related to the equity component of the senior unsecured convertible notes and the unamortized deferred financing costs on the senior unsecured notes of $77.8 million and $21.6 million, respectively, $626.0 million of borrowings under the Oasis Credit Facility and $117.0 million of borrowings under a $200.0 million senior secured revolving credit facility among OMP, as parent, OMP Operating LLC, a subsidiary of OMP, as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "OMP Credit Facility," and, together with the Oasis Credit Facility, the "Revolving Credit Facilities"). The Revolving Credit Facilities are recorded at values that approximate fair value since their variable interest rates are 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 $2,086.8 million at March 31, 2018.

On April 30, 2018, the Company launched and priced a private placement offering of $400.0 million in aggregate principal amount of 6.25% senior unsecured notes due 2026. The offering is expected to close on May 14, 2018, and the Company intends to use the net proceeds from the offering to fund tender offers (the "Tender Offers") to purchase for cash, subject to certain conditions, up to $400.0 million in aggregate purchase price, excluding accrued and unpaid interest, of its outstanding 7.25% senior notes due 2019, 6.5% senior notes due 2021, 6.875% senior notes due 2022 and 6.875% senior notes due 2023 (collectively, the "Tender Notes"). The Tender Offers are being made pursuant to an Offer to Purchase and Consent Solicitation

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Statement dated April 30, 2018. To the extent that the Tender Offers are not completed or the net proceeds from the offering exceed the amount needed to fund the Tender Offers, the Company will use the remaining net proceeds from the offering for general corporate purposes, which may include redemptions or repurchases of the Tender Notes, reducing borrowings under the Oasis Credit Facility, repaying other indebtedness, working capital or funding capital expenditures and acquisitions. The Company's 7.25% senior notes due February 1, 2019 are excluded from current liabilities in its Condensed Consolidated Balance Sheet at March 31, 2018 because the Company has the intent and ability to refinance this obligation on a long-term basis as demonstrated by the private placement offering and Tender Offers.

Senior secured revolving line of credit. The Company has the Oasis Credit Facility with an overall senior secured line of credit of $2,500.0 million as of March 31, 2018, which has a maturity date of the earlier of (i) April 13, 2020, and (ii) 90 days prior to the maturity date of the 7.25% senior unsecured notes due February 1, 2019 (the "2019 Notes"), of which $54.3 million is outstanding, to the extent such 2019 Notes are not retired or refinanced to have a maturity date at least 90 days after April 13, 2020. The Oasis Credit Facility is restricted to a borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On February 26, 2018, the Company entered into an amendment to the Oasis Credit Facility, resulting in the aggregate elected commitment being increased from $1,150.0 million to $1,350.0 million and two new lenders being added to the bank group. On April 19, 2018, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2018, resulting in the Company entering into the Twelfth Amendment to the Second Amended and Restated Credit Agreement to the Oasis Credit Facility, which (i) reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, (ii) removed the legacy anti-cash hoarding provisions, (iii) reduced the coverage threshold with respect to mortgaged properties and (iv) amended the asset sale covenant to give the Company additional flexibility to trade oil and gas properties. In addition, in connection with such amendment, OP Permian became a guarantor under the Oasis Credit Facility. The next redetermination of the Oasis Credit Facility's borrowing base is scheduled for October 1, 2018.

At March 31, 2018, the Company had $626.0 million of London Interbank Offered Rate ("LIBOR") loans at a weighted average interest rate of 3.6% and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing base committed capacity of $710.0 million. On a quarterly basis, the Company also pays a commitment fee that can range from 0.375% to 0.500% 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 Oasis Credit Facility as of March 31, 2018.

OMP Operating LLC revolving line of credit. Through its ownership of OMP, the Company has the OMP Credit Facility with a revolving line of credit of $200.0 million, which has a maturity date of September 25, 2022. The OMP Credit Facility is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. The OMP Credit Facility includes a letter of credit sublimit of $10.0 million and a swingline loans sublimit of $10.0 million. The borrowing capacity on the OMP Credit Facility may be increased up to $400.0 million, subject to certain conditions.

Borrowings under the OMP Credit Facility bear interest at a rate per annum equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the OMP Credit Agreement) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the OMP Credit Agreement). The applicable margin for borrowings under the OMP Credit Facility varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75%, and (b) in the case of ABR Loans or swingline loans, 0.75% to 1.75%. The unused portion of the OMP Credit Facility is subject to a commitment fee ranging from 0.375% to 0.500%.

The OMP Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (1) consolidated leverage ratio, (2) consolidated secured leverage ratio and (3) consolidated interest coverage ratio (each covenant as described in the OMP Credit Facility). OMP Operating LLC was in compliance with the financial

covenants of the OMP Credit Facility as of March 31, 2018. All obligations of OMP Operating LLC, as the borrower under the OMP Credit Facility, are unconditionally guaranteed on a joint and several basis by OMP, OMP Operating LLC and Bighorn DevCo LLC.

At March 31, 2018, the Company had $117.0 million of borrowings outstanding under the OMP Credit Facility. As of March 31, 2018, the weighted average interest rate on borrowings under the OMP Credit Facility was 3.6%.

Senior unsecured notes. At March 31, 2018, 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.

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Senior unsecured convertible notes. At March 31, 2018, the Company had $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 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 March 31, 2018, 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.

11. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the three months ended March 31, 2018:

	(In thousands)
Balance at December 31, 2017	$ 48,799
Liabilities incurred during period	2,703
Liabilities settled during period	(1)
Accretion expense during period[(1)]	665
Revisions to estimates	84
Balance at March 31, 2018	$ 52,250

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

At March 31, 2018, 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.

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12. Income Taxes

The Company's effective tax rate for the three months ended March 31, 2018 was 18.2% as compared to an effective tax rate of 40.2% for the same period in 2017. The effective tax rate for the three months ended March 31, 2018 was lower than the statutory federal rate of 21% primarily due to (i) the tax impact of a decrease in the Company's deferred state tax rate as a result of the Permian Basin Acquisition and (ii) the portion of OMP's earnings attributable to the non-controlling public limited partners, which are not taxable to the Company. These decreases are partially offset by (i) state income taxes, (ii) an increase in the valuation allowance recorded against the Company's Montana net operating loss carryforwards and (iii) a permanent difference related to equity-based compensation shortfalls.

The effective tax rate for the three months ended March 31, 2017 was higher than the statutory federal rate of 35% primarily due to state taxes and a permanent difference related to nondeductible executive compensation. These increases were partially offset by a permanent difference related to equity-based compensation windfalls.

Valuation allowance. The Company had valuation allowances of $3.3 million and $1.2 million as of March 31, 2018 and December 31, 2017, respectively, because the Company has concluded it is more likely than not that it will be unable to utilize certain state net operating loss carryforwards and charitable contribution carryforwards. As of each reporting date, the Company's management considers new evidence, both positive and negative, which could impact management's view with regard to future realization of deferred tax assets. During the three months ended March 31, 2018, the valuation allowance was increased by $2.2 million, primarily against the Company's Montana net operating loss carryforwards, as a result of the Permian Basin Acquisition and the corresponding shift of projected future taxable income into other states.

Tax Cuts and Jobs Act. On December 22, 2017, the U.S. government enacted the Tax Act, which made broad and complex changes to the U.S. tax code. Due to the complexities involved in the accounting for the enactment of the new law, the SEC issued SAB 118, which provides guidance on the accounting for the tax effects of the Tax Act. SAB 118 provides a measurement period that should not extend beyond one year from the Tax Act enactment date to complete the accounting under ASC 740, "Income Taxes." In accordance with SAB 118, the Company was able to make reasonable estimates on certain effects of the Tax Act in the financial statements as of December 31, 2017. There have been no material changes to the provisional estimate as disclosed in the Company's 2017 Form 10-K. The Company will continue to analyze the impact of the new law and additional impacts will be recorded as they are identified during the measurement period provided for in SAB 118.

13. Equity-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 three months ended March 31, 2018, employees and non-employee directors of the Company were granted restricted stock awards equal to 2,865,780 shares of common stock with a $9.58 weighted average grant date per share value. Equity-based compensation expense recorded for restricted stock awards for the three months ended March 31, 2018 was $4.8 million and $5.4 million for the three months ended March 31, 2017. Equity-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.

The Company accounts for 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, stock price on the date of grant, 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 stock prices over a historical period

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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 equity-based compensation expense of the PSUs granted during the three months ended March 31, 2018:

Risk-free interest rate	2.08% - 2.31%
Oasis volatility	72.88 %
Oasis initial value	$8.82
Oasis stock price on date of grant	$9.27

During the three months ended March 31, 2018, officers of the Company were granted 854,400 PSUs with a $12.71 weighted average grant date per share value. Equity-based compensation expense recorded for PSUs for the three months ended March 31, 2018 was $1.9 million and $1.3 million for the three months ended March 31, 2017. Equity-based compensation expense is included in general and administrative expenses on the Company's Condensed Consolidated Statements of Operations.

OMP phantom unit awards. In September 2017, OMP GP adopted the Oasis Midstream Partners LP 2017 Long Term Incentive Plan ("OMP LTIP"). The OMP LTIP provides for the grant, from time to time at the discretion of the board of directors of OMP GP, of options, unit appreciation rights, restricted units, phantom units, unit awards, substitute awards, other unit-based awards or cash awards and includes any tandem distribution equivalent rights with respect to certain awards. Each award of phantom unit vests in equal amounts each year over a three-year period, and compensation expense will be recognized over the requisite service period.

The Phantom Units are accounted for as liability-classified awards since the awards will settle in cash, and equity-based compensation cost is accounted for under the fair value method in accordance with GAAP. Under the fair value method for liability-classified awards, compensation cost is remeasured each reporting period at fair value based upon the closing price of a publicly traded common unit. The Company will reimburse OMP for the cash settlement amount of these awards, which is included in general and administrative expenses on the Company's Condensed Consolidated Statements of Operations. Equity-based compensation expense relating to the OMP phantom unit awards for the three months ended March 31, 2018 was $0.1 million. The Company did not record any equity-based compensation related to the OMP phantom unit awards for the three months ended March 31, 2017 because the awards were granted in the fourth quarter of 2017.

OMP restricted unit awards. During the three months ended March 31, 2018, certain directors of OMP were granted 12,200 restricted unit awards which vest over a one-year period with a weighted average grant date fair value of $16.50 per common unit. These awards are accounted for as equity-classified awards since the awards will settle in common units upon vesting. Equity-based compensation cost is accounted for under the fair value method in accordance with GAAP. Under the fair value method for equity-classified awards, compensation cost is measured at the grant date based on the fair value of the award and is recognized over the vesting period. Compensation cost associated with these awards was approximately $0.1 million for the three months ended March 31, 2018 and is included in general and administrative expenses on the Company's Condensed Consolidated Statements of Operations.

14. Earnings (Loss) Per Share

Basic earnings (loss) per share is computed by dividing the earnings (loss) attributable to Oasis 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) attributable to Oasis available to common stockholders in the calculation of diluted earnings (loss) per share.

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The following is a calculation of the basic and diluted weighted average shares outstanding for the three months ended March 31, 2018 and 2017:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Basic weighted average common shares outstanding	290,105	233,068
Dilutive effect of restricted stock awards and PSUs	1,633	3,238
Dilutive effect of senior convertible notes[(1)]	—	1,594
Diluted weighted average common shares outstanding	291,738	237,900

(1) No contingently issuable shares related to senior convertible notes were included in computing earnings (loss) per share for the three months ended March 31, 2018 because the effect was anti-dilutive.

For the three months ended March 31, 2018 and 2017, the Company excluded these unvested stock awards from the diluted earnings (loss) per share calculation because the effects were anti-dilutive based on the treasury stock method. 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 March 31,	
	2018	2017
	(In thousands)	
Restricted stock awards and PSUs	5,281	2,884

The Company issued its Senior Convertible Notes in September 2016 (see Note 10 – 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 March 31, 2018, 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 months ended March 31, 2018.

15. 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 produced and flowback 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 and other third-party operators. Revenues for the midstream segment are primarily derived from produced and flowback water pipeline transport, produced and flowback 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, which is defined as segment operating revenues less operating expenses, including DD&A. 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 March 31, 2018:					
Revenues from non-affiliates	$381,708	$27,922	$11,586	$—	$421,216
Inter-segment revenues	—	36,640	33,302	(69,942)	—
Total revenues	381,708	64,562	44,888	(69,942)	421,216
Operating income	79,962	32,237	8,148	(7,362)	112,985
Other expense	(108,146)	(258)	(41)	—	(108,445)
Income (loss) before income taxes including non-controlling interests	$(28,184)	$31,979	$8,107	$(7,362)	$4,540
Three months ended March 31, 2017:					
Revenues from non-affiliates	$264,883	$14,606	$5,627	$—	$285,116
Inter-segment revenues	—	23,035	15,352	(38,387)	—
Total revenues	264,883	37,641	20,979	(38,387)	285,116
Operating income (loss)	968	20,763	(3,592)	1,953	20,092
Other income (expense)	19,768	(2)	4	—	19,770
Income (loss) before income taxes	$20,736	$20,761	$(3,588)	$1,953	$39,862
At March 31, 2018:					
Property, plant and equipment, net	$6,600,397	$732,801	$47,310	$(193,902)	$7,186,606
Total assets[(1)]	6,994,927	752,301	50,605	(158,903)	7,638,930
At December 31, 2017:					
Property, plant and equipment, net	$5,663,323	$649,923	$46,779	$(186,539)	$6,173,486
Total assets[(1)]	6,050,255	663,614	52,800	(151,539)	6,615,130

(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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16. Commitments and Contingencies

The Company has various contractual obligations in the normal course of its operations. As of March 31, 2018, there have been no material changes to the Company's future commitments as disclosed in Note 18 in the Company's 2017 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 Oasis Midstream Services LLC, 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.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleges new legal theories for being entitled to enforce the underlying contracts and added Bighorn DevCo LLC, Bobcat DevCo LLC and Beartooth DevCo LLC as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

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 that do not apply to the Company. The Company filed an answer denying all of Mirada's claims and intends and continues to vigorously defend against Mirada's claims. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial is currently scheduled for May 2019. 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, financial condition, results of operations or cash flows. 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. In addition, the Company has agreed to indemnify OMP for any losses resulting from this litigation under the omnibus agreement it entered into with OMP at the time of OMP's initial public offering.

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17. Condensed Consolidating Financial Information

The Notes (see Note 10 – 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 operating units, including OMP, which is accounted for on a consolidated basis, do not guarantee the Notes ("Non-Guarantor Subsidiaries").

The following financial information reflects consolidating financial information of the parent company, Oasis Petroleum Inc. ("Issuer"), its Guarantors on a combined basis and the Non-Guarantor Subsidiaries on a combined basis, prepared on the equity basis of accounting. 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.

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Condensed Consolidating Balance Sheet

	March 31, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands, except share data)				
ASSETS					
Current assets					
Cash and cash equivalents	$179	$13,508	$ 4,048	$—	$17,735
Accounts receivable, net	—	370,001	977	—	370,978
Accounts receivable - affiliates	373,954	55,939	57,087	(486,980)	—
Inventory	—	23,039	—	—	23,039
Prepaid expenses	447	4,760	747	—	5,954
Intangible assets, net	—	958	—	—	958
Other current assets	—	193	—	—	193
Total current assets	374,580	468,398	62,859	(486,980)	418,857
Property, plant and equipment					
Oil and gas properties (successful efforts method)	—	8,914,811	—	(3,715)	8,911,096
Other property and equipment	—	220,293	743,578	—	963,871
Less: accumulated depreciation, depletion, amortization and impairment	—	(2,647,665)	(40,696)	—	(2,688,361)
Total property, plant and equipment, net	—	6,487,439	702,882	(3,715)	7,186,606
Investments in and advances to subsidiaries	5,198,126	428,245	—	(5,626,371)	—
Deferred income taxes	191,671	—	—	(191,671)	—
Long-term inventory	—	12,506	—	—	12,506
Other assets	—	19,062	1,899	—	20,961
Total assets	$5,764,377	$7,415,650	$ 767,640	$(6,308,737)	$7,638,930
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$—	$15,534	$ 593	$—	$16,127
Accounts payable - affiliates	40,406	431,041	15,533	(486,980)	—
Revenues and production taxes payable	—	245,198	—	—	245,198
Accrued liabilities	284	165,899	67,239	—	233,422
Accrued interest payable	19,872	736	73	—	20,681
Derivative instruments	—	149,657	—	—	149,657
Advances from joint interest partners	—	4,888	—	—	4,888
Other current liabilities	—	40	—	—	40
Total current liabilities	60,562	1,012,993	83,438	(486,980)	670,013
Long-term debt	1,953,534	626,000	117,000	—	2,696,534
Deferred income taxes	—	498,420	—	(191,671)	306,749
Asset retirement obligations	—	50,624	1,331	—	51,955
Derivative instruments	—	19,699	—	—	19,699
Other liabilities	—	7,822	—	—	7,822
Total liabilities	2,014,096	2,215,558	201,769	(678,651)	3,752,772
Stockholders' equity					
Capital contributions from affiliates	—	3,640,084	224,008	(3,864,092)	—

Common stock, $0.01 par value: 450,000,000 shares authorized; 319,384,813 shares issued and 317,363,008 shares outstanding	3,154	—	—	—	3,154
Treasury stock, at cost: 2,021,805 shares	(28,200)	—	—	—	(28,200)
Additional paid-in-capital	3,055,003	8,994	—	(8,994)	3,055,003
Retained earnings	720,324	1,413,388	21,593	(1,436,730)	718,575
Oasis share of stockholders' equity	3,750,281	5,062,466	245,601	(5,309,816)	3,748,532
Non-controlling interests	—	137,626	320,270	(320,270)	137,626
Total stockholders' equity	3,750,281	5,200,092	565,871	(5,630,086)	3,886,158
Total liabilities and stockholders' equity	$5,764,377	$7,415,650	$ 767,640	$(6,308,737)	$7,638,930

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Condensed Consolidating Balance Sheet

	December 31, 2017				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands, except share data)				
ASSETS					
Current assets					
Cash and cash equivalents	$178	$15,659	$ 883	$—	$16,720
Accounts receivable, net	—	362,746	834	—	363,580
Accounts receivable - affiliates	425,668	46,020	85,818	(557,506)	—
Inventory	—	19,367	—	—	19,367
Prepaid expenses	267	6,586	778	—	7,631
Derivative instruments	—	344	—	—	344
Other current assets	—	193	—	—	193
Total current assets	426,113	450,915	88,313	(557,506)	407,835
Property, plant and equipment					
Oil and gas properties (successful efforts method)	—	7,840,921	—	(1,966)	7,838,955
Other property and equipment	—	214,818	653,928	—	868,746
Less: accumulated depreciation, depletion, amortization and impairment	—	(2,499,867)	(34,348)	—	(2,534,215)
Total property, plant and equipment, net	—	5,555,872	619,580	(1,966)	6,173,486
Investments in and advances to subsidiaries	4,790,976	422,132	—	(5,213,108)	—
Derivative instruments	—	9	—	—	9
Deferred income taxes	183,568	—	—	(183,568)	—
Long-term inventory	—	12,200	—	—	12,200
Other assets	—	19,587	2,013	—	21,600
Total assets	$5,400,657	$6,460,715	$ 709,906	$(5,956,148)	$6,615,130
LIABILITIES AND STOCKHOLDERS' EQUITY					
Current liabilities					
Accounts payable	$—	$13,370	$ —	$—	$13,370
Accounts payable - affiliates	34,382	511,486	11,638	(557,506)	—
Revenues and production taxes payable	—	213,995	—	—	213,995
Accrued liabilities	216	177,446	58,818	—	236,480
Accrued interest payable	38,796	53	114	—	38,963
Derivative instruments	—	115,716	—	—	115,716
Advances from joint interest partners	—	4,916	—	—	4,916
Other current liabilities	—	40	—	—	40
Total current liabilities	73,394	1,037,022	70,570	(557,506)	623,480
Long-term debt	1,949,606	70,000	78,000	—	2,097,606
Deferred income taxes	—	489,489	—	(183,568)	305,921
Asset retirement obligations	—	47,195	1,316	—	48,511
Derivative instruments	—	19,851	—	—	19,851
Other liabilities	—	6,182	—	—	6,182
Total liabilities	2,023,000	1,669,739	149,886	(741,074)	3,101,551
Stockholders' equity					

Capital contributions from affiliates	—	3,264,691	234,935	(3,499,626)	—
Common stock, $0.01 par value: 450,000,000 shares authorized; 270,627,014 shares issued and 269,295,466 shares outstanding	2,668	—	—	—	2,668
Treasury stock, at cost: 1,331,548 shares	(22,179)	—	—	—	(22,179)
Additional paid-in-capital	2,677,217	8,922	—	(8,922)	2,677,217
Retained earnings	719,951	1,379,475	11,639	(1,393,080)	717,985
Oasis share of stockholders' equity	3,377,657	4,653,088	246,574	(4,901,628)	3,375,691
Non-controlling interests	—	137,888	313,446	(313,446)	137,888
Total stockholders' equity	3,377,657	4,790,976	560,020	(5,215,074)	3,513,579
Total liabilities and stockholders' equity	$5,400,657	$6,460,715	$ 709,906	$(5,956,148)	$6,615,130

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Condensed Consolidating Statement of Operations

	Three Months Ended March 31, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Revenues					
Oil and gas revenues	—	363,671	—	—	$ 363,671
Purchased oil and gas sales	—	18,037	—	—	18,037
Midstream revenues	—	1,150	61,421	(34,649)	27,922
Well services revenues	—	11,586	—	—	11,586
Total revenues	—	394,444	61,421	(34,649)	421,216
Operating expenses					
Lease operating expenses	—	55,699	—	(10,918)	44,781
Midstream operating expenses	—	746	17,116	(9,877)	7,985
Well services operating expenses	—	7,387	—	—	7,387
Marketing, transportation and gathering expenses	—	26,672	—	(5,659)	21,013
Purchased oil and gas expenses	—	17,998	—	—	17,998
Production taxes	—	31,000	—	—	31,000
Depreciation, depletion and amortization	—	146,227	6,364	(3,326)	149,265
Exploration expenses	—	769	—	—	769
Impairment	—	93	—	—	93
General and administrative expenses	7,232	17,678	6,150	(3,120)	27,940
Total operating expenses	7,232	304,269	29,630	(32,900)	308,231
Operating income (loss)	(7,232)	90,175	31,791	(1,749)	112,985
Other income (expense)					
Equity in earnings of subsidiaries	32,164	31,529	—	(63,693)	—
Net loss on derivative instruments	—	(71,116)	—	—	(71,116)
Interest expense, net of capitalized interest	(32,446)	(4,438)	(262)	—	(37,146)
Other expense	—	(183)	—	—	(183)
Total other expense	(282)	(44,208)	(262)	(63,693)	(108,445)
Income (loss) before income taxes	(7,514)	45,967	31,529	(65,442)	4,540
Income tax benefit (expense)	8,104	(8,932)	—	—	(828)
Net income including non-controlling interests	590	37,035	31,529	(65,442)	3,712
Less: Net income attributable to non-controlling interests	—	3,122	21,574	(21,574)	3,122
Net income attributable to Oasis	$590	$ 33,913	$ 9,955	$ (43,868)	$ 590

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Condensed Consolidating Statement of Operations

	Three Months Ended March 31, 2017			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Revenues				
Oil and gas revenues	$—	$ 237,252	$ —	$ 237,252
Purchased oil and gas sales	—	27,631	—	27,631
Midstream revenues	—	14,606	—	14,606
Well services revenues	—	5,627	—	5,627
Total revenues	—	285,116	—	285,116
Operating expenses				
Lease operating expenses	—	43,872	—	43,872
Midstream operating expenses	—	3,327	—	3,327
Well services operating expenses	—	4,560	—	4,560
Marketing, transportation and gathering expenses	—	10,951	—	10,951
Purchased oil and gas expenses	—	28,002	—	28,002
Production taxes	—	20,299	—	20,299
Depreciation, depletion and amortization	—	126,666	—	126,666
Exploration expenses	—	1,489	—	1,489
Impairment	—	2,682	—	2,682
General and administrative expenses	7,065	16,111	—	23,176
Total operating expenses	7,065	257,959	—	265,024
Operating income (loss)	(7,065)	27,157	—	20,092
Other income (expense)				
Equity in earnings of subsidiaries	49,103	—	(49,103)	—
Net gain on derivative instruments	—	56,075	—	56,075
Interest expense, net of capitalized interest	(32,851)	(3,470)	—	(36,321)
Other income	—	16	—	16
Total other income	16,252	52,621	(49,103)	19,770
Income before income taxes	9,187	79,778	(49,103)	39,862
Income tax benefit (expense)	14,638	(30,675)	—	(16,037)
Net income	$23,825	$ 49,103	$ (49,103)	$ 23,825

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Condensed Consolidating Statement of Cash Flows

	Three Months Ended March 31, 2018				
	Parent/ Issuer	Combined Guarantor Subsidiaries	Combined Non-guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)				
Cash flows from operating activities:					
Net income including non-controlling interests	$590	$ 37,035	$ 31,529	$ (65,442)	$ 3,712
Adjustments to reconcile net income including non-controlling interests to net cash provided by operating activities:					
Equity in earnings of subsidiaries	(32,164)	(31,529)	—	63,693	—
Depreciation, depletion and amortization	—	146,227	6,364	(3,326)	149,265
Impairment	—	93	—	—	93
Deferred income taxes	(8,104)	8,932	—	—	828
Derivative instruments	—	71,116	—	—	71,116
Equity-based compensation expenses	6,418	273	63	—	6,754
Deferred financing costs amortization and other	3,929	1,432	114	—	5,475
Working capital and other changes:					
Change in accounts receivable	51,714	(23,888)	36,992	(70,526)	(5,708)
Change in inventory	—	(3,672)	—	—	(3,672)
Change in prepaid expenses	(180)	641	31	—	492
Change in long-term inventory and other assets	—	(315)	—	—	(315)
Change in accounts payable, interest payable and accrued liabilities	(12,832)	(66,000)	8,062	70,526	(244)
Change in other liabilities	—	563	—	—	563
Net cash provided by operating activities	9,371	140,908	83,155	(5,075)	228,359
Cash flows from investing activities:					
Capital expenditures	—	(169,994)	(84,844)	—	(254,838)
Acquisitions	—	(520,728)	—	—	(520,728)
Derivative settlements	—	(36,974)	—	—	(36,974)
Advances from joint interest partners	—	(28)	—	—	(28)
Net cash used in investing activities	—	(727,724)	(84,844)	—	(812,568)
Cash flows from financing activities:					
Proceeds from Revolving Credit Facilities	—	1,413,000	57,000	—	1,470,000
Principal payments on Revolving Credit Facilities	—	(857,000)	(18,000)	—	(875,000)
Deferred financing costs	—	(215)	—	—	(215)
Purchases of treasury stock	(6,021)	—	—	—	(6,021)
Distributions to non-controlling interests	—	34,866	(38,316)	—	(3,450)
Investment in subsidiaries / capital contributions from parent	(3,259)	(5,986)	4,170	5,075	—
Other	(90)	—	—	—	(90)
Net cash provided by (used in) financing activities	(9,370)	584,665	4,854	5,075	585,224
Increase (decrease) in cash and cash equivalents	1	(2,151)	3,165	—	1,015
Cash and cash equivalents at beginning of period	178	15,659	883	—	16,720
Cash and cash equivalents at end of period	$179	$ 13,508	$ 4,048	$ —	$ 17,735

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Condensed Consolidating Statement of Cash Flows

	Three Months Ended March 31, 2017			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
	(In thousands)			
Cash flows from operating activities:				
Net income	$23,825	$ 49,103	$ (49,103)	$ 23,825
Adjustments to reconcile net income to net cash provided by operating activities:				
Equity in earnings of subsidiaries	(49,103)	—	49,103	—
Depreciation, depletion and amortization	—	126,666	—	126,666
Impairment	—	2,682	—	2,682
Deferred income taxes	(14,638)	30,675	—	16,037
Derivative instruments	—	(56,075)	—	(56,075)
Equity-based compensation expenses	6,498	210	—	6,708
Deferred financing costs amortization and other	3,665	1,275	—	4,940
Working capital and other changes:				
Change in accounts receivable	51,230	(27,952)	(45,756)	(22,478)
Change in inventory	—	(3,679)	—	(3,679)
Change in prepaid expenses	(59)	341	—	282
Change in other current assets	(2)	(108)	—	(110)
Change in long-term inventory and other assets	—	(4)	—	(4)
Change in accounts payable, interest payable and accrued liabilities	(13,321)	(26,375)	45,756	6,060
Change in other current liabilities	—	2,945	—	2,945
Net cash provided by operating activities	8,095	99,704	—	107,799
Cash flows from investing activities:				
Capital expenditures	—	(96,047)	—	(96,047)
Derivative settlements	—	(7,960)	—	(7,960)
Advances from joint interest partners	—	(759)	—	(759)
Net cash used in investing activities	—	(104,766)	—	(104,766)
Cash flows from financing activities:				
Proceeds from Oasis Credit Facility	—	246,000	—	246,000
Principal payments on Oasis Credit Facility	—	(241,000)	—	(241,000)
Purchases of treasury stock	(5,419)	—	—	(5,419)
Investment in subsidiaries / capital contributions from parent	(2,610)	2,610	—	—
Other	(55)	—	—	(55)
Net cash provided by (used in) financing activities	(8,084)	7,610	—	(474)
Increase in cash and cash equivalents	11	2,548	—	2,559
Cash and cash equivalents at beginning of period	166	11,060	—	11,226
Cash and cash equivalents at end of period	$177	$ 13,608	$ —	$ 13,785

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18. 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 previously disclosed.

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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, 2017 ("2017 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 2017 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, including ownership interests in a master limited partnership;
- owning and operating a well services company;
- infrastructure for produced and flowback water gathering and disposal;
- gathering, transportation and marketing of oil and natural gas, both in the Williston and Delaware Basins and other regions in the United States;
- property acquisitions, including our recent acquisition of oil and gas properties in the Delaware 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;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- certain factors flagged elsewhere in this Form 10-Q.

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 onshore, unconventional oil and natural gas resources in the United States. Since our inception, we have acquired properties that provide current production and significant upside potential through further development. Our drilling activity has primarily been directed toward projects that we believe can provide us with repeatable successes in the Bakken and Three Forks formations. On February 14, 2018, we acquired approximately 22,000 net acres in the Delaware Basin from Forge Energy, LLC, representing our initial entry into the Delaware Basin (the "Permian Basin Acquisition"). The Permian Basin Acquisition more than doubled our core net inventory and allows us to further capitalize on our operational strengths. Oasis Petroleum North America LLC ("OPNA") and Oasis Petroleum Permian LLC ("OP Permian") conduct our exploration and production activities and own our proved and unproved oil and natural gas properties located in the North Dakota and Montana regions of the Williston Basin and the Texas regions of the Delaware Basin, respectively. We also operate a midstream services business through OMS Holdings 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 midstream services business is conducted by Oasis Midstream Partners LP ("OMP" or "Oasis Midstream"), which completed an initial public offering in September 2017. The Company owns the general partner and a majority of the outstanding units of OMP. 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 a $1,600.0 million senior secured revolving credit facility among OPNA, as Borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "Oasis Credit Facility") and a $200.0 million senior secured revolving credit facility among OMP, as parent, OMP Operating LLC, a subsidiary of OMP, as borrower, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (the "OMP Credit Facility," and, together with the Oasis Credit Facility, our "Revolving Credit Facilities"), 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.

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Due to the geographic concentration of our oil and natural gas properties in the Williston Basin and Delaware 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. A substantial or extended decline in 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, 92% 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 $2.00 per barrel primarily due to the additional takeaway capacity of the Dakota Access Pipeline of over 450,000 barrels per day.

Highlights:

- We produced 76,819 barrels of oil equivalent per day (“Boepd”) in the first quarter of 2018;
- We completed and placed on production 17 gross (11.2 net) operated wells, including 16 gross (10.2 net) operated wells in the Williston Basin and 1 gross (1.0 net) operated well in the Delaware Basin, in the first quarter of 2018;
- Our oil differentials have improved to $1.67 off of NYMEX West Texas Intermediate crude oil index price (“WTI”) in the first quarter of 2018;
- Lease operating expenses (“LOE”) per barrels of oil equivalent (“Boe”) decreased over 15% to $6.48 in the first quarter of 2018 compared to $7.71 per Boe in the first quarter of 2017;
- Total exploration and production (“E&P”) capital expenditures (“CapEx”) were $176.9 million for the three months ended March 31, 2018;
- We closed on the Permian Basin Acquisition from Forge Energy on February 14, 2018, adding an average of approximately 3,600 Boepd of production and approximately 22,000 net undeveloped acres; and
- Net cash provided by operating activities was $228.4 million for the three months ended March 31, 2018. Adjusted EBITDA, a non-GAAP financial measure, was $232.9 million for the three months ended March 31, 2018. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to net income (loss) including non-controlling interests and net cash provided by operating activities, see “Non-GAAP Financial Measures” below.

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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 produced and flowback water pipeline transport, produced and flowback 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.

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

	Three Months Ended March 31,		
	2018	2017	Change
Operating results (in thousands)			
Revenues			
Oil revenues	$323,386	$208,594	$114,792
Natural gas revenues	40,285	28,658	11,627
Purchased oil and gas sales	18,037	27,631	(9,594)
Midstream revenues	27,922	14,606	13,316
Well services revenues	11,586	5,627	5,959
Total revenues	$421,216	$285,116	$136,100
Production data			
Oil (MBbl)	5,284	4,435	849
Natural gas (MMcf)	9,777	7,512	2,265
Oil equivalents (MBoe)	6,914	5,687	1,227
Average daily production (Boepd)	76,819	63,192	13,627
Average sales prices			
Oil, without derivative settlements (per Bbl)	$61.20	$47.03	$14.17
Oil, with derivative settlements (per Bbl)[1]	54.18	45.24	8.94
Natural gas, without derivative settlements (per Mcf)[2]	4.12	3.81	0.31
Natural gas, with derivative settlements (per Mcf)[1][2]	4.13	3.82	0.31

(1) Realized prices include gains or losses on cash settlements for our 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.

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Three months ended March 31, 2018 as compared to three months ended March 31, 2017

Oil and gas revenues. Our oil and gas revenues increased $126.4 million, or 53%, to $363.7 million during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. This increase was primarily driven by a $65.1 million increase due to the higher oil and natural gas sales prices, coupled with a $61.3 million increase driven by higher oil and natural gas production amounts sold during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. Average oil sales prices, without derivative settlements, increased by $14.17 per barrel to an average of $61.20 per barrel, and average natural gas sales prices, which includes the value for natural gas and natural gas liquids and is without derivative settlements, increased by $0.31 per Mcf to an average of $4.12 per Mcf for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. Average daily production sold increased by 13,627 Boepd to 76,819 Boepd during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. The increase in average daily production sold was primarily a result of our 63.7 total net well completions in the Williston Basin during the twelve months ended March 31, 2018 and the Permian Basin Acquisition.

Purchased oil and gas sales. Purchased oil and gas sales, which consist primarily of the sale of crude oil purchased for blending at our crude oil terminal, decreased $9.6 million to $18.0 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 primarily due to lower volumes used for blending.

Midstream revenues. Midstream revenues increased $13.3 million to $27.9 million during the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. This increase was primarily driven by an $8.4 million increase related to higher natural gas volumes gathered, compressed and processed, coupled with a $3.3 million increase related to higher produced and flowback water volumes driven by an increase in producing wells.

Well services revenues. Our well services revenues increased by $6.0 million to $11.6 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017, primarily due to a $4.9 million increase in well completion revenue due to the increased activity as a result of adding a second fracturing fleet during the third quarter of 2017, coupled with a $0.7 million increase in equipment rentals.

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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 March 31,		
	2018	2017	Change
	(In thousands, except per Boe of production)		
Operating expenses			
Lease operating expenses	$44,781	$43,872	$909
Midstream operating expenses	7,985	3,327	4,658
Well services operating expenses[1]	7,387	4,560	2,827
Marketing, transportation and gathering expenses	21,013	10,951	10,062
Purchased oil and gas expenses	17,998	28,002	(10,004)
Production taxes	31,000	20,299	10,701
Depreciation, depletion and amortization	149,265	126,666	22,599
Exploration expenses	769	1,489	(720)
Impairment	93	2,682	(2,589)
General and administrative expenses[1]	27,940	23,176	4,764
Total operating expenses	308,231	265,024	43,207
Operating income	112,985	20,092	92,893
Other income (expense)			
Net gain (loss) on derivative instruments	(71,116)	56,075	(127,191)
Interest expense, net of capitalized interest	(37,146)	(36,321)	(825)
Other income (expense)	(183)	16	(199)
Total other income (expense)	(108,445)	19,770	(128,215)
Income before income taxes	4,540	39,862	(35,322)
Income tax expense	(828)	(16,037)	15,209
Net income including non-controlling interests	3,712	23,825	(20,113)
Less: Net income attributable to non-controlling interests	3,122	—	3,122
Net income attributable to Oasis	$590	$23,825	$(23,235)
Costs and expenses (per Boe of production)			
Lease operating expenses	$6.48	$7.71	$(1.23)
Marketing, transportation and gathering expenses	3.04	1.93	1.11
Production taxes	4.48	3.57	0.91
Depreciation, depletion and amortization	21.59	22.27	(0.68)
General and administrative expenses[1]	4.04	4.08	(0.04)

(1) For the three months ended March 31, 2017, well services operating expenses have been adjusted to include $0.7 million for certain well services direct field labor compensation expenses which were previously recognized in general and administrative expenses on our Condensed Consolidated Statements of Operations.

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Three months ended March 31, 2018 as compared to three months ended March 31, 2017

Lease operating expenses. Lease operating expenses increased $0.9 million to $44.8 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. 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 Permian Basin Acquisition, coupled with an increase in workover costs during the three months ended March 31, 2018. Lease operating expenses per Boe decreased period over period from $7.71 per Boe to $6.48 per Boe primarily due to higher production volumes period over period.

Midstream operating expenses. Midstream operating expenses represent third-party working interest owners' share of operating expenses incurred by OMS. The $4.7 million increase period over period was primarily related to a $1.9 million increase in gas gathering, compression and processing expenses and a $1.5 million increase in produced and flowback water expenses driven by increased production.

Well services operating expenses. Well services operating expenses represent third-party working interest owners' share of completion service costs, cost of goods sold and operating expenses incurred by OWS. The $2.8 million increase period over period was primarily attributable to increased well completion activity due to the addition of a second fracturing fleet during the third quarter of 2017.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $10.0 million, or $1.11 per Boe, for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017, which was primarily attributable to higher oil gathering and transportation expenses related to an increase in volumes being transported on the Dakota Access Pipeline, which started in the second quarter of 2017. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis increased to $3.01 during the three months ended March 31, 2018 as compared to $1.77 during the three months ended March 31, 2017 primarily due to the higher aforementioned costs.

Purchased oil and gas expenses. Purchased oil and gas expenses, which represent the crude oil purchased primarily for blending at our crude oil terminal, decreased $10.0 million to $18.0 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 primarily due to lower volumes used for blending.

Production taxes. Our production taxes as a percentage of oil and natural gas sales were 8.5% and 8.6% for the three months ended March 31, 2018 and 2017, respectively. The production tax rate decreased period over period primarily due to a lower oil production mix, coupled with the addition of Delaware Basin assets following the Permian Basin Acquisition in February 2018 which bear a lower average production tax rate than Williston Basin assets. North Dakota's natural gas production tax is $0.0555 per Mcf, while its crude oil tax structure is based on a 5% production tax and a 5% oil extraction tax, resulting in a combined tax rate of 10% of crude oil revenues.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $22.6 million to $149.3 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. This increase in DD&A expense period over period was a result of production increases from our wells completed during the three months ended March 31, 2018 coupled with the Permian Basin Acquisition, offset by an decrease in the DD&A rate to $21.59 per Boe for the three months ended March 31, 2018 as compared to $22.27 per Boe for the three months ended March 31, 2017. The decrease in the DD&A rate was primarily due to higher recoverable reserves as a result of higher oil and natural gas prices, coupled with lower costs and higher estimated ultimate recoveries on our more recently completed wells.

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 $0.1 million and $2.7 million for the three months ended March 31, 2018 and 2017, respectively, related to acreage expiring in future periods because there were no current plans to drill or extend the leases prior to their expiration. No impairment charges of proved oil and gas or other properties were recorded for the three months ended March 31, 2018 and 2017.

General and administrative expenses ("G&A"). Our G&A increased $4.7 million to $27.9 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017. E&P G&A increased $3.3 million period over period primarily due to costs related to the Permian Basin Acquisition and increased employee compensation expenses as a result of organizational growth. OMS G&A increased $1.7 million period over period

primarily due to increased expenses associated with OMP being a public company coupled with increased employee compensation expenses as a result of organizational growth. OWS G&A decreased $0.2 million to $1.3 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017.

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Derivative instruments. As a result of entering into derivative contracts and the effect of the forward strip oil and gas price changes, we incurred a $71.1 million net loss on derivative instruments, including net cash settlement payments of $37.0 million, for the three months ended March 31, 2018, and a $56.1 million net gain on derivative instruments, including net cash settlement payments of $8.0 million for the three months ended March 31, 2017. 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.

Interest expense. Interest expense increased $0.8 million to $37.1 million for the three months ended March 31, 2018 as compared to the three months ended March 31, 2017 primarily due to interest expense related to our borrowings under our Revolving Credit Facilities, offset by an increase in capitalized interest due to higher costs for work in progress assets. For the three months ended March 31, 2018, the weighted average debts outstanding under the Oasis Credit Facility and the OMP Credit Facility were $396.2 million and $106.4 million, respectively, and the weighted average interest rates incurred on the outstanding borrowings were 3.5% and 3.4%, respectively. For the three months ended March 31, 2017, the weighted average debt outstanding under the Oasis Credit Facility was $400.8 million, and the weighted average interest rate incurred on the outstanding borrowings were 2.5%. Interest capitalized during the three months ended March 31, 2018 and 2017 was $4.5 million and $2.8 million, respectively.

Income taxes. The income tax expense for the three months ended March 31, 2018 and 2017 was recorded at 18.2% and 40.2% of pre-tax income, respectively. Our effective tax rate for the three months ended March 31, 2018 was lower than the effective tax rate for the three months ended March 31, 2017 due to (i) the change in the corporate tax rate under the Tax Act, (ii) the tax impact of a decrease in our deferred state tax rate as a result of the Permian Basin Acquisition, (iii) the portion of OMP's earnings attributable to the non-controlling public limited partners, which are not taxable to us, and (iv) the impact of non-deductible executive compensation. These decreases to tax expense are partially offset by (i) an increase in the valuation allowance recorded against our Montana net operating loss carryforwards and (ii) the impact of equity-based compensation shortfalls in 2018 as compared to the impact of equity-based compensation windfalls in 2017.

Liquidity and Capital Resources

Our primary sources of liquidity as of the date of this report have been proceeds from our Notes (as defined below), borrowings under our Revolving Credit Facilities, 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 cash 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 Senior Notes. We continually monitor potential capital sources, including equity and debt financings and potential asset monetization opportunities, in order to enhance liquidity and decrease leverage. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Our cash flows for the three months ended March 31, 2018 and 2017 are presented below:

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Net cash provided by operating activities	$228,359	$107,799
Net cash used in investing activities	(812,568)	(104,766)
Net cash provided by (used in) financing activities	585,224	(474)
Increase in cash and cash equivalents	$1,015	$2,559

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 $228.4 million and $107.8 million for the three months ended March 31, 2018 and 2017, respectively. The change in cash flows from operating activities for the period ended March 31, 2018 as compared to 2017 was primarily the result of the 30% increase in realized prices for oil and the 8% increase in realized prices for natural gas, coupled with our 22% increase in oil and natural gas production.

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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 $251.2 million at March 31, 2018 primarily due to increases in our current liabilities, primarily due to the impact of increases in the forward commodity price curve on our short-term derivative instruments coupled with increases in our accrued liabilities for drilling and development costs. As of March 31, 2018, we had $810.7 million of liquidity available, including $17.7 million in cash and cash equivalents and $793.0 million of aggregate unused borrowing capacity available under our Revolving Credit Facilities. At March 31, 2017, we had a working capital deficit of $83.3 million.

Cash flows used in investing activities

Net cash used in investing activities was $812.6 million and $104.8 million during the three months ended March 31, 2018 and 2017, respectively. Net cash used in investing activities during the three months ended March 31, 2018 was primarily attributable to $520.7 million in acquisitions primarily for the Permian Basin Acquisition, coupled with $254.8 million in capital expenditures primarily for drilling and development costs. Net cash used in investing activities during the three months ended March 31, 2017 was primarily attributable to $96.0 million in capital expenditures primarily for drilling and development costs.

Our capital expenditures are summarized in the following table:

	Three Months Ended March 31, 2018 (In thousands)
Capital expenditures:	
E&P	$176,937
Well services	4,262
Other capital expenditures[(1)]	6,287
Total capital expenditures before acquisitions and midstream	187,486
Midstream	88,794
Total capital expenditures before acquisitions	276,280
Acquisitions	890,948
Total capital expenditures[(2)]	$1,167,228

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

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

Our total 2018 capital expenditure budget is approximately $1,090 million to $1,170 million, which includes approximately $815 million to $855 million for E&P capital expenditures, including approximately $700 million to $730 million focused in the Williston Basin and approximately $115 million to $125 million focused in the Delaware Basin, approximately $235 million to $275 million for infrastructure and midstream capital expenditures and approximately $40 million of other capital expenditures, including capitalized interest, well services equipment and administrative capital.

While we have budgeted approximately $1,090 million to $1,170 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling and operations results as the year progresses. Additionally, if we acquire additional acreage, our capital expenditures may be higher than budgeted. We believe that cash on hand, including cash flows from operating activities and availability

under our Revolving Credit Facilities should be sufficient to fund our 2018 capital expenditure budget and to meet our future obligations. However, because the operated wells funded by our 2018 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 plan 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 substantially or for an extended period of time, we could defer a significant portion of our planned 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

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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 (used in) financing activities

Net cash provided by financing activities was $585.2 million and net cash used in financing activities was $0.5 million for the three months ended March 31, 2018 and 2017, respectively. For the three months ended March 31, 2018, cash provided by financing activities was primarily due to proceeds from the borrowings under our Revolving Credit Facilities, partially offset by principal payments on our Revolving Credit Facilities. Net cash used in financing activities during the three months ended March 31, 2017 was primarily due to principal payments on our Oasis Credit Facility, partially offset by proceeds from the borrowings under our Oasis Credit Facility. For both the three months ended March 31, 2018 and 2017, cash was used in financing activities for the purchases of treasury stock for shares that employees surrendered back to us to pay tax withholdings upon the vesting of restricted stock awards.

Senior secured revolving line of credit. We have the Oasis Credit Facility with an overall senior secured line of credit of $2,500.0 million as of March 31, 2018. The Oasis 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. The maturity date of the Oasis Credit Facility is the earlier of (i) April 13, 2020, and (ii) 90 days prior to the maturity date of the 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”), of which $54.3 million is outstanding, to the extent such 2019 Notes are not retired or refinanced to have a maturity date at least 90 days after April 13, 2020. On February 26, 2018, we entered into an amendment to the Oasis Credit Facility, resulting in the aggregate elected commitment being increased from $1,150.0 million to $1,350.0 million and two new lenders being added to the bank group. On April 19, 2018, the lenders under the Oasis Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2018, resulting in us entering into the Twelfth Amendment to the Second Amended and Restated Credit Agreement to the Oasis Credit Facility, which (i) reaffirmed the borrowing base and the aggregate elected commitment at $1,600.0 million and $1,350.0 million, respectively, (ii) removed the legacy anti-cash hoarding provisions, (iii) reduced the coverage threshold with respect to mortgaged properties and (iv) amended the asset sale covenant to give us additional flexibility to trade oil and gas properties. In addition, in connection with such amendment, OP Permian became a guarantor under the Oasis Credit Facility. The next redetermination of the Oasis Credit Facility’s borrowing base is scheduled for October 1, 2018.

As of March 31, 2018, we had $626.0 million of borrowings at a weighted average interest rate of 3.6% and $14.0 million of outstanding letters of credit issued under the Oasis Credit Facility, resulting in an unused borrowing base committed capacity of $710.0 million.

The Oasis 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 Oasis Credit Facility) to consolidated Interest Expense (as defined in the Oasis Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter;
- a requirement that we maintain a Current Ratio (as defined in the Oasis Credit Facility) of consolidated current assets (including unused borrowing base committed capacity and with exclusions as described in the Oasis Credit Facility) to consolidated current liabilities (with exclusions as described in the Oasis Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter; and
- if the Aggregate Elected Commitment Amounts (as defined in the Oasis Credit Facility) exceed $1,350.0 million, a requirement that we maintain a ratio of total debt (as defined in the Oasis Credit Facility) to consolidated EBITDAX

(as defined in the Oasis Credit Facility) of no greater than 4.25 to 1.0 for the first two full fiscal quarters ending after the first date on which they exceed $1,350.0 million and no greater than 4.0 to 1.0 for each fiscal quarter thereafter. The Oasis 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 Oasis Credit Facility to be immediately due and payable. We were in compliance with the financial covenants of the Oasis Credit Facility as of March 31, 2018. Given the possible fluctuation in commodity

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prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

OMP Operating LLC revolving line of credit. Through our majority ownership of OMP, we have the OMP Credit Facility. The OMP Credit Facility has a maturity date of September 25, 2022 and is available to fund working capital and to finance acquisitions and other capital expenditures of OMP. The OMP Credit Facility includes a letter of credit sublimit of $10.0 million and a swingline loans sublimit of $10.0 million. The borrowing capacity on the OMP Credit Facility may be increased up to $400.0 million, subject to certain conditions.

At March 31, 2018, we had $117.0 million of borrowings outstanding under the OMP Credit Facility. As of March 31, 2018, the weighted average interest rate on borrowings under the OMP Credit Facility was 3.6%.

The OMP Credit Facility includes certain financial covenants as of the end of each fiscal quarter, including a (1) consolidated total leverage ratio, (2) consolidated senior secured leverage ratio and (3) consolidated interest coverage ratio (each covenant as described in the OMP Credit Agreement). All obligations of OMP Operating LLC, as the borrower under the OMP Credit Facility, are unconditionally guaranteed on a joint and several basis by OMP, OMP Operating LLC and Bighorn DevCo LLC. OMP Operating LLC was in compliance with the financial covenants of the OMP Credit Facility at March 31, 2018.

Senior unsecured notes. As of March 31, 2018, our long-term debt includes outstanding senior unsecured note 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 6.5% senior unsecured notes due November 1, 2021 (the “2021 Notes”), $937.1 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”) and $366.1 million of 6.875% senior unsecured notes due January 15, 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.

On April 30, 2018, we launched and priced a private placement offering of $400.0 million in aggregate principal amount of 6.25% senior unsecured notes due 2026. The offering is expected to close on May 14, 2018, and we intend to use the net proceeds from the offering to fund tender offers (the “Tender Offers”) to purchase for cash, subject to certain conditions, up to $400.0 million in aggregate purchase price, excluding accrued and unpaid interest, of the Senior Notes (the “Tender Notes”). The Tender Offers are being made pursuant to an Offer to Purchase and Consent Solicitation Statement dated April 30, 2018. To the extent that the Tender Offers are not completed or the net proceeds from the offering exceed the amount needed to fund the Tender Offers, we will use the remaining net proceeds from the offering for general corporate purposes, which may include redemptions or repurchases of the Tender Notes, reducing borrowings under the Oasis Credit Facility, repaying other indebtedness, working capital or funding capital expenditures and acquisitions. Our 2019 Notes are excluded from current liabilities in our Condensed Consolidated Balance Sheet at March 31, 2018 because we have the intent and ability to refinance this obligation on a long-term basis as demonstrated by the private placement offering and Tender Offers.

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. We were in compliance with the terms of the indentures for the Senior Notes as of March 31, 2018.

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Senior unsecured convertible notes. At March 31, 2018, we had $300.0 million of 2.625% senior unsecured convertible notes due September 2023 (the "Senior Convertible Notes"). 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, 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 our 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, we 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 March 31, 2018, none of the contingent conditions allowing holders of the Senior Convertible Notes to convert these notes had been met. In addition, we were in compliance with the terms of the indentures for the Senior Convertible Notes as of March 31, 2018.

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) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis 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) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis 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.

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 March 31,	
	2018	2017
	(In thousands)	
Interest expense	$37,146	$36,321

Capitalized interest	4,451	2,820
Amortization of deferred financing costs	(1,761)	(1,690)
Amortization of debt discount	(2,618)	(2,355)
Cash Interest	$37,218	$35,096

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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.

The following table presents reconciliations of the GAAP financial measures of net income (loss) including non-controlling interests 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:

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	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Net income including non-controlling interests	$3,712	$23,825
Net (gain) loss on derivative instruments	71,116	(56,075)
Derivative settlements[1]	(36,974)	(7,960)
Interest expense, net of capitalized interest	37,146	36,321
Depreciation, depletion and amortization	149,265	126,666
Impairment	93	2,682
Exploration expenses	769	1,489
Equity-based compensation expenses	6,754	6,708
Income tax expense	828	16,037
Other non-cash adjustments	209	912
Adjusted EBITDA	232,918	150,605
Adjusted EBITDA attributable to non-controlling interests	3,911	—
Adjusted EBITDA attributable to Oasis	229,007	150,605
Cash Interest	(37,218)	(35,096)
Capital expenditures[2]	(1,167,228)	(109,795)
Capitalized interest	4,451	2,820
Free Cash Flow	$(970,988)	$8,534
Net cash provided by operating activities	$228,359	$107,799
Derivative settlements[1]	(36,974)	(7,960)
Interest expense, net of capitalized interest	37,146	36,321
Exploration expenses	769	1,489
Deferred financing costs amortization and other	(5,475)	(4,940)
Changes in working capital	8,884	16,984
Other non-cash adjustments	209	912
Adjusted EBITDA	232,918	150,605
Adjusted EBITDA attributable to non-controlling interests	3,911	—
Adjusted EBITDA attributable to Oasis	229,007	150,605
Cash Interest	(37,218)	(35,096)
Capital expenditures[2]	(1,167,228)	(109,795)
Capitalized interest	4,451	2,820
Free Cash Flow	$(970,988)	$8,534

(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 (including acquisitions) reflected in the table above differ from the amounts shown in the statements of cash flows in our condensed consolidated financial statements because amounts reflected in the table 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. Acquisitions totaled $890.9 million and $2.6 million for the three months ended March 31, 2018 and 2017, respectively.

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The following tables present reconciliations of the GAAP financial measure of income (loss) before income taxes including non-controlling interests 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 March 31,	
	2018	2017
	(In thousands)	
Income (loss) before income taxes including non-controlling interests	$(28,184)	$20,736
Net (gain) loss on derivative instruments	71,116	(56,075)
Derivative settlements[1]	(36,974)	(7,960)
Interest expense, net of capitalized interest	36,884	36,321
Depreciation, depletion and amortization	145,203	124,409
Impairment	93	2,682
Exploration expenses	769	1,489
Equity-based compensation expenses	6,454	6,499
Other non-cash adjustments	209	912
Adjusted EBITDA	$195,570	$129,013

(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 March 31,	
	2018	2017
	(In thousands)	
Income before income taxes including non-controlling interests	$31,979	$20,761
Interest expense, net of capitalized interest	262	—
Depreciation, depletion and amortization	6,629	3,458
Equity-based compensation expenses	370	348
Adjusted EBITDA	$39,240	$24,567

Well Services

	Three Months Ended March 31,	
	2018	2017
	(In thousands)	
Income (loss) before income taxes including non-controlling interests	$8,107	$(3,588)
Depreciation, depletion and amortization	3,690	3,164
Equity-based compensation expenses	385	396
Adjusted EBITDA	$12,182	$(28)

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Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share

We define Adjusted Net Income (Loss) Attributable to Oasis as net income (loss) after adjusting 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, (2) the impact of net income attributable to non-controlling interests and (3) the non-cash and non-recurring items' impact on taxes based on our effective tax rate applicable to those adjusting items, excluding net income attributable to non-controlling interests, in the same period. Adjusted Net Income (Loss) Attributable to Oasis is not a measure of net income (loss) as determined by GAAP. We define Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share as Adjusted Net Income (Loss) Attributable to Oasis divided by diluted weighted average shares outstanding. Management believes that the presentation of Adjusted Net Income (Loss) Attributable to Oasis and Adjusted Diluted Earnings (Loss) Attributable to Oasis 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 are excluded from guidance provided by the Company.

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

	Three Months Ended March 31,	
	2018	2017
	(In thousands, except per share data)	
Net income attributable to Oasis	$ 590	$ 23,825
Net (gain) loss on derivative instruments	71,116	(56,075)
Derivative settlements[1]	(36,974)	(7,960)
Impairment	93	2,682
Amortization of deferred financing costs	1,761	1,690
Amortization of debt discount	2,618	2,355
Other non-cash adjustments	209	912
Tax impact[2]	(9,217)	21,103
Adjusted Net Income (Loss) Attributable to Oasis	$ 30,196	$ (11,468)
Diluted earnings attributable to Oasis per share	$ 0.00	$ 0.10
Net (gain) loss on derivative instruments	0.24	(0.24)
Derivative settlements[1]	(0.13)	(0.03)
Impairment	0.00	0.01
Amortization of deferred financing costs	0.01	0.01
Amortization of debt discount	0.01	0.01
Other non-cash adjustments	0.00	0.00
Tax impact[2]	(0.03)	0.09
Adjusted Diluted Earnings (Loss) Attributable to Oasis Per Share	$ 0.10	$ (0.05)
Diluted weighted average shares outstanding[3]	291,738	233,068
Effective tax rate applicable to adjustment items	23.7 %	37.4 %

(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.

(3) No unvested stock awards were included in computing Adjusted Diluted Loss Attributable to Oasis Per Share for the three months ended March 31, 2017 because the effect was anti-dilutive due to adjusted net loss.

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Fair Value of Financial Instruments

See Note 6 – Fair Value Measurements to our unaudited condensed consolidated financial statements for a discussion of our money market funds and derivative instruments and their related fair value measurements. See also Item 3. "Quantitative and Qualitative Disclosures about Market Risk" below.

Critical Accounting Policies and Estimates

There have been no material changes in our critical accounting policies and estimates from those disclosed in our 2017 Annual Report. See Note 2 – Summary of Significant Accounting Policies to our unaudited condensed consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

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 2017 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 March 31, 2018, 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.

The following is a summary of our derivative contracts as of March 31, 2018:

Commodity	Settlement Period	Derivative Instrument	Volumes		Weighted Average Prices				Fair Value Asset (Liability)
					Swap	Sub-Floor	Floor	Ceiling	
									(In thousands)
Crude oil	2018	Swaps	11,029,000	Bbl	$51.92				$ (125,062)
Crude oil	2018	Two-way collar	825,000	Bbl			$48.67	$53.07	(8,649)
Crude oil	2019	Swaps	5,489,000	Bbl	$53.05				(32,612)
Crude oil	2019	Two-way collar	93,000	Bbl			$48.67	$53.07	(812)
Crude oil	2019	Three-way collar	2,004,000	Bbl		$ 40.00	$50.00	$65.99	(2,217)
Crude oil	2020	Swaps	403,000	Bbl	$53.47				(1,261)
Crude oil	2020	Three-way collar	186,000	Bbl		$ 40.00	$50.00	$65.99	(113)
Natural gas	2018	Swaps	6,325,000	MMbtu	$3.05				1,369
									$ (169,357)

A 10% increase in crude oil prices would decrease the fair value of our derivative position by approximately $109.1 million, while a 10% decrease in crude oil prices would increase the fair value by approximately $106.8 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 6.50% 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 March 31, 2018.

At March 31, 2018, we had $626.0 million of borrowings and $14.0 million of outstanding letters of credit issued under the Oasis 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 each of the Revolving Credit Facilities as an Alternate Based Rate or “ABR” loan). At March 31, 2018, the outstanding borrowings under the Oasis Credit Facility bore interest at LIBOR plus a 1.75% margin.

At March 31, 2018, we had $117.0 million of borrowings issued under the OMP Credit Facility, which were subject to a per annum interest rate equal to the applicable margin (as described below) plus (i) with respect to Eurodollar Loans, the Adjusted LIBO Rate (as defined in the OMP Credit Facility) or (ii) with respect to ABR Loans, the greatest of (A) the Prime Rate in effect on such day, (B) the Federal Funds Effective Rate in effect on such day plus 1/2 of 1.00% or (C) the Adjusted LIBO Rate for a one-month interest period on such day plus 1.00% (each as defined in the OMP Credit Facility). The applicable margin for borrowings under the OMP Credit Facility varies from (a) in the case of Eurodollar Loans, 1.75% to 2.75%, and (b) in the case of ABR Loans or swingline loans, 0.75% to 1.75%. The unused portion of the OMP Credit Facility is subject to a commitment fee ranging from 0.375% to 0.500%. At March 31, 2018, the outstanding borrowings under the OMP Credit Facility bore interest at LIBOR plus a 1.75% 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 the Oasis Credit Facility or the OMP 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 months ended March 31, 2018. 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 the Oasis 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 the Oasis Credit Facility, which also carry investment grade ratings. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative liability position of $169.4 million at March 31, 2018.

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 March 31, 2018.

Item 4. — Controls and Procedures

Evaluation of disclosure controls and procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer (“CEO”), our principal executive officer, and our Chief Financial Officer (“CFO”), our principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of March 31, 2018. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms, and that such information is accumulated and communicated to our management, including our CEO and CFO as appropriate, to allow timely decisions regarding required disclosure. Based on this evaluation, our CEO and CFO have concluded that our disclosure controls and procedures were effective at March 31, 2018.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during the three months ended March 31, 2018 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 Oasis Midstream Services LLC, 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.

On February 2, 2018 and February 16, 2018, Mirada filed a second and third amended petition, respectively. In these filings, Mirada alleges new legal theories for being entitled to enforce the underlying contracts, and added Bighorn DevCo LLC, Bobcat DevCo LLC and Beartooth DevCo LLC as defendants, asserting that these entities were created in bad faith in an effort to avoid contractual obligations owed to Mirada.

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 all of Mirada's claims and intends and continues to vigorously defend against Mirada's claims. Discovery is ongoing, and each of the parties has made a number of procedural filings and motions, and additional filings and motions can be expected over the course of the claim. Trial is currently scheduled for May 2019. 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, financial condition, results of operations or cash flows. 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. In addition, the Company has agreed to indemnify OMP for any losses resulting from this litigation under the omnibus agreement it entered into with OMP at the time of OMP's initial public offering.

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 2017 Annual Report. Other than as described below, there have been no material changes in our risk factors from those described in our 2017 Annual Report.

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The 2015 final rule attempting to clarify federal jurisdiction under the Clean Water Act ("CWA") over waters of the United States has had its implementation date extended to February 2020, while lawsuits challenging the 2015 rule resume in federal district court.

In June 2015, the U.S. Environmental Protection Agency ("EPA") and the U.S. Army Corps of Engineers ("Corps") published a final rule outlining their position on federal jurisdictional reach over waters of the United States, including jurisdictional wetlands, but legal challenges to this rule followed, and the rule was stayed nationwide, pending resolution of the court challenges. In January 2017, the U.S. Supreme Court accepted review of the rule to determine whether jurisdiction rests with the federal district or appellate courts and, in a decision issued in January 2018, held that legal challenges of the rule must be heard at the district rather than appellate court level. The stay on the 2015 rule was lifted in February 2018 and, in March 2018, a judge resumed a lawsuit in which a North Dakota-led coalition of states are challenging the June 2015 rule. Notwithstanding legal challenges to the 2015 rule, the EPA and the Corps published a final rule in February 2018 specifying that the contested 2015 rule would not take effect until February 6, 2020. As a result, future implementation of the 2015 rule is uncertain at this time. To the extent the 2015 rule or a revised rule expands the scope of the CWA's jurisdiction in areas where we operate, it could impose additional permitting obligations on our operations.

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

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

Issuer purchases of equity securities. The following table contains information about our acquisition of equity securities during the three months ended March 31, 2018:

Period	Total Number of Shares Exchanged[1]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
January 1 - January 31, 2018	456,641	$ 9.06	—	—
February 1 - February 28, 2018	3,176	8.51	—	—
March 1 - March 31, 2018	230,440	8.06	—	—
Total	690,257	$ 8.72	—	—

(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
4.1	Registration Rights Agreement, dated February 14, 2018, between the Oasis Petroleum Inc. and Forge Energy, LLC (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on February 16, 2018, and incorporated herein by reference).
4.2(a)	Seventh Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of April 27, 2018 among the Company, the Guarantors and U.S. Bank National Association, as trustee.
4.3(a)	Eighth Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of April 27, 2018 among the Company, the Guarantors and U.S. Bank National Association, as trustee.

10.1	Eleventh Amendment to Second Amended and Restated Credit Agreement, dated as of February 26, 2018, by and 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 February 28, 2018, and incorporated herein by reference).
10.2(a)	Twelfth Amendment to Second Amended and Restated Credit Agreement, dated as of April 19, 2018, by and 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.
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.

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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: May 8, 2018 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)