Oasis Petroleum Inc.
Form 10-K
February 25, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

ý ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission file number: 1-34776

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

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

(281) 404-9500
(Registrant's telephone number, including area code)
Securities Registered Pursuant to Section 12(b) of the Act:

Common Stock, par value $0.01 per share (Title of Class)	New York Stock Exchange (Name of Exchange)

Securities Registered Pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No ¨
Indicate by check mark if the Registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No ý
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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements

incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý
Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of “large accelerated filer”, “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the Registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No ý
Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant’s most recently completed second fiscal quarter: $2,205,627,149
Number of shares of registrant’s common stock outstanding as of February 18, 2016: 180,556,502

Documents Incorporated By Reference:
Portions of the registrant’s definitive proxy statement for its 2016 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2015, are incorporated by reference into Part III of this report for the year ended December 31, 2015.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), 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 Annual Report on Form 10-K, 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 Annual Report on Form 10-K, the words “could,” “believe,” “anticipate,” “intend,” “estimate,” “expect,” “may,” “continue,” “ “potential,” “project” and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

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

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. 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 Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under “Item 1A. Risk

Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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PART I

Item 1. Business

Overview

Oasis Petroleum Inc. (together with our consolidated subsidiaries, the "Company," "we," "us," or "our") was originally formed in 2007 and was incorporated pursuant to the laws of the State of Delaware in 2010. We are an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the North Dakota and Montana regions of the Williston Basin. Oasis Petroleum North America LLC ("OPNA") conducts our exploration and production activities and owns our proved and unproved oil and natural gas properties. We also operate a well services business through Oasis Well Services LLC ("OWS") and a midstream services business through Oasis Midstream Services LLC ("OMS").

As of December 31, 2015, we have accumulated 484,745 net leasehold acres in the Williston Basin, of which approximately 91% is held by production. We are currently exploiting significant resource potential from the Bakken and Three Forks formations, which are present across a substantial portion of our acreage. We believe the location, size and concentration of our acreage create an opportunity for us to achieve cost, recovery and production efficiencies through the development of our project inventory. Our management team has a proven track record in identifying, acquiring and executing large, repeatable development drilling programs, which we refer to as "resource conversion" opportunities, and has substantial Williston Basin experience.

In 2015, we completed and placed on production 80 gross operated wells in the Williston Basin and had average daily production of 50,477 Boe per day. As of December 31, 2015, we had 1,095 gross (595.5 net) producing wells in the Bakken and Three Forks formations. DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 218.2 MMBoe as of December 31, 2015, of which 68% were classified as proved developed and of which 85% were oil.

Our business strategy

Our goal is to enhance value by investing capital to build reserves, production and cash flows at attractive rates of return through the following strategies:

- Efficiently develop our Williston Basin leasehold position. We are developing our acreage position to maximize the value of our resource potential, while maintaining flexibility to preserve future value when oil prices are low. During 2014, when the NYMEX West Texas Intermediate crude oil index price ("WTI") averaged $92.07 per barrel throughout the year, we completed and brought on production 195 gross (147.4 net) operated Bakken and Three Forks wells in the Williston Basin. During 2015, when WTI averaged $48.75 per barrel, we completed and brought on production 80 gross (62.4 net) operated Bakken and Three Forks wells. As of December 31, 2015, we had 85 gross operated wells waiting on completion in the Bakken and Three Forks formations. Our 2016 capital plan, which was finalized when WTI for 2016 was projected to average approximately $35.00 per barrel, contemplates operating two rigs and completing and placing on production approximately 46 gross (28.6 net) operated wells. We have the ability to increase or decrease the number of wells drilled and the number of wells completed during 2016 based on market conditions and program results.
- Enhance returns by focusing on operational and cost efficiencies. Our management team is focused on continuous improvement of our operations and has significant experience in successfully operating cost-efficient development programs. We believe the magnitude and concentration of our acreage within the Williston Basin, particularly in the core of the play, has and will continue to provide us with the opportunity to capture economies of scale, including the ability to drill multiple wells from a single drilling pad into multiple formations, utilizing centralized production and oil, gas and water fluid handling facilities and infrastructure, and reducing the time and cost of rig mobilization. In addition, we expect OWS and OMS to continue to provide operational synergies going forward compared to third party providers.
- Adopt and employ leading drilling and completion techniques. Our team is focused on enhancing our drilling and completion techniques to maximize overall well economics. We have significantly reduced the number of days that it takes to drill wells, and we believe completion techniques have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well. High intensity completion techniques continue to deliver production performance greater than prior completion techniques. We continuously

evaluate our internal drilling and completion results and monitor the results of other operators to improve our operating practices. This continued evolution may enhance our initial production rates, increase ultimate recovery factors, lower well capital costs and improve rates of return on invested capital.

- Maintain financial flexibility. Based on current market conditions, we have a strong liquidity position. In February 2016, we completed a public equity offering of 39,100,000 shares, raising $182.9 million of net proceeds to be used for general corporate purposes and to fund a portion of our 2016 capital expenditures. We have no near-term debt maturities,

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and, in April 2015, we amended our revolving credit facility to extend its maturity date from April 2018 to April 2020, provided that our 7.25% senior unsecured notes due 2019 are retired or refinanced 90 days prior to their maturity. In October 2015, we successfully completed consent solicitations respecting amendments to the indentures governing certain of our senior unsecured notes, which amendments allow us to incur secured credit facilities indebtedness up to the amount of our borrowing base at the time of the incurrence, but not to exceed $1,525.0 million. In February 2016, our spring borrowing base redetermination was completed, resulting in a borrowing base decrease from $1,525.0 million to $1,150.0 million. As of December 31, 2015, we had $138.0 million of borrowings and $5.2 million of outstanding letters of credit under our revolving credit facility and $1,199.4 million of pro forma liquidity available, including adjustments for the new borrowing base and the net proceeds from our public equity offering in February 2016. Our liquidity position, along with internally generated cash flows from operations and settlements from our derivative contracts in 2016, will provide continued financial flexibility as we actively manage the pace of development on our acreage position in the Williston Basin. We also currently believe we have access to the public and private capital markets, and we intend to maintain a balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise. We are also continuing to evaluate options to monetize certain assets in our portfolio, which could result in increased liquidity and lower leverage.

- Pursue strategic acquisitions with significant resource potential. As opportunities arise, we intend to identify and acquire additional acreage and producing assets in the Williston Basin to supplement our existing operations. Going forward, we may selectively target additional basins that would allow us to employ our resource conversion strategy on large undeveloped acreage positions similar to what we have accumulated in the Williston Basin.

Our competitive strengths

We have a number of competitive strengths that we believe will help us to successfully execute our business strategies:

- Substantial leasehold position in one of North America's leading unconventional oil-resource plays. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken and Three Forks formations. As of December 31, 2015, substantially all of our 484,745 net leasehold acres in the Williston Basin were highly prospective in the Bakken and Three Forks formations, and 85% of our 218.2 MMBoe estimated net proved reserves in this area were comprised of oil. In addition, we have 442,292 net acres held by production as of December 31, 2015. In 2015, we increased per well capital efficiency through our focused development efforts in our core acreage and improved operational efficiency, coupled with lower service costs from third-party vendors and OWS. In 2016, we will continue to concentrate our drilling and completion activities in our core acreage, which is located in the deepest part of the Williston Basin.
- Large, multi-year project inventory. We believe we have a large inventory of potential drilling locations that we have not yet drilled, a majority of which are operated by us. We plan to slow the pace of completions again in 2016 to 46 gross (28.6 net) operated wells in the Williston Basin in order to maintain financial flexibility and preserve the value of our inventory.
- Management team with proven operating and acquisition skills. Our senior management team has extensive expertise in the oil and gas industry. Our senior technical team has an average of more than 25 years of industry experience, including experience in multiple North American resource plays as well as experience in international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our team's proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, our technical team possesses substantial expertise in horizontal drilling techniques and managing and acquiring large development programs.
- Incentivized management team. In 2015, an average of 57% of our executive officers' overall compensation was in long-term equity-based incentive awards, and such officers owned 2.5% of our outstanding common stock as of December 31, 2015. We believe our executive officers' ownership interest in us provides them with significant incentives to grow the value of our business for the benefit of all stakeholders.
- Operating control over the majority of our portfolio. In order to maintain better control over our asset portfolio, we have established a leasehold position comprised primarily of properties that we expect to operate. As of December 31, 2015, 97% of our estimated net proved reserves were attributable to properties that we expect to operate, and our

average working interest in our 2016 operated completion plan is expected to be 66%. Approximately 92% of our 2016 drilling and completion capital expenditure budget is related to operated wells. Controlling operations will allow us to dictate the pace of development and better manage the costs, type and timing of exploration and development activities. We believe that maintaining operational control over the majority of our acreage will allow us to better pursue our strategies of enhancing returns through operational and cost efficiencies and maximizing hydrocarbon recovery through continuous improvement of drilling and completion techniques. We are also better able to control infrastructure

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investment to drive down operating costs, optimize oil price realizations and increase the monetization of gas production.

Our operations

Estimated net proved reserves

The table below summarizes our estimated net proved reserves and related PV-10 at December 31, 2015, 2014 and 2013 based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers. In preparing its reports, DeGolyer and MacNaughton evaluated 100% of the reserves and discounted values at December 31, 2015, 2014 and 2013 in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC") applicable to companies involved in oil and natural gas producing activities. Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure do not include probable or possible reserves and were determined using the preceding twelve months' unweighted arithmetic average of the first-day-of-the-month index prices for oil and natural gas, which were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $50.16/Bbl for oil and $2.63/MMBtu for natural gas, $95.28/Bbl for oil and $4.35/MMBtu for natural gas and $96.96/Bbl for oil and $3.66/MMBtu for natural gas for the years ended December 31, 2015, 2014 and 2013, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. The information in the following table does not give any effect to or reflect our commodity derivatives. Future operating costs, production taxes and capital costs were based on current costs as of each year-end. For a definition of proved reserves under the SEC rules, please see the "Glossary of oil and natural gas terms" included at the end of this report. For more information regarding our independent reserve engineers, please see "Independent petroleum engineers" below.

	At December 31,					
	2015		2014		2013	
Reserves Data:						
Estimated proved reserves:						
Oil (MMBbls)	184.9		235.4		198.6	
Natural gas (Bcf)	199.8		220.1		176.0	
Total estimated proved reserves (MMBoe)	218.2		272.1		227.9	
Percent oil	85	%	87	%	87	%
Estimated proved developed reserves:						
Oil (MMBbls)	127.4		127.3		106.8	
Natural gas (Bcf)	120.8		114.0		92.2	
Total estimated proved developed reserves (MMBoe)	147.6		146.3		122.1	
Percent proved developed	68	%	54	%	54	%
Estimated proved undeveloped reserves:						
Oil (MMBbls)	57.5		108.1		91.8	
Natural gas (Bcf)	79.0		106.1		83.8	
Total estimated proved undeveloped reserves (MMBoe)	70.7		125.7		105.8	
PV-10 (in millions)[1]	$2,022.7		$5,481.4		$5,486.9	
Standardized Measure (in millions)[2]	$1,914.3		$3,981.7		$3,727.6	

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

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

Estimated net proved reserves at December 31, 2015 were 218.2 MMBoe, a 20% decrease from estimated net proved reserves of 272.1 MMBoe at December 31, 2014 primarily due to revisions related to lower commodity prices, partially offset by our 2015 drilling program and well completions as well as lower estimated future operating and capital costs. Our proved developed reserves increased 1.3 MMBoe, or 1%, to 147.6 MMBoe for the year ended December 31, 2015 from 146.3 MMBoe for the year ended December 31, 2014, primarily due to our 2015 drilling program, including the completion of 80 gross (62.4 net) operated wells, partially offset by production and higher abandonment rates resulting from lower commodity price assumptions. Our proved undeveloped reserves decreased to 70.7 MMBoe for the year ended December 31, 2015 from 125.7 MMBoe for the year ended December 31, 2014 due to increases from our 2015 drilling program offset by the removal of proved undeveloped reserves that are not economic at the lower oil price or are no longer aligned with our anticipated five-year drilling plan.

Estimated net proved reserves at December 31, 2014 were 272.1 MMBoe, a 19% increase from estimated net proved reserves of 227.9 MMBoe at December 31, 2013 primarily as a result of our 2014 drilling program and well completions, partially offset by the sale of certain non-operated properties in and around our Sanish position (the "Sanish Divestiture") during the year ended December 31, 2014. Our proved developed reserves increased 24.2 MMBoe, or 20%, to 146.3 MMBoe for the year ended December 31, 2014 from 122.1 MMBoe for the year ended December 31, 2013, primarily due to our 2014 drilling program, including the completion of 195 gross (147.4 net) operated wells. Our proved undeveloped reserves increased to 125.7 MMBoe for the year ended December 31, 2014 from 105.8 MMBoe for the year ended December 31, 2013, primarily due to our 2014 drilling program and changes to align our proved undeveloped reserves with our anticipated five-year drilling plan.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2015, 2014 and 2013:

	At December 31,		
	2015	2014	2013
		(In millions)	
PV-10	$2,022.7	$5,481.4	$5,486.9
Present value of future income taxes discounted at 10%	108.4	1,499.7	1,759.3
Standardized Measure of discounted future net cash flows	$1,914.3	$3,981.7	$3,727.6

The PV-10 of our estimated net proved reserves at December 31, 2015 was $2,022.7 million, a 63% decrease from PV-10 of $5,481.4 million at December 31, 2014. This decrease was primarily due to lower commodity price assumptions and a decrease in reserves, partially offset by a reduction in future development costs year over year.

Estimated future net revenues

Future net revenues represent projected revenues from the sale of our estimated net proved reserves (excluding derivative contracts) net of production and development costs (including operating expenses and production taxes). The following table sets forth the estimated future net revenues from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices used in projecting net revenues at December 31, 2015, 2014 and

2013:

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	At December 31,		
	2015	2014	2013
	(In millions, except price data)		
Future net revenues	$3,827.9	$11,999.3	$11,685.6
Present value of future net revenues:			
Before income tax (PV-10)	2,022.7	5,481.4	5,486.9
After income tax (Standardized Measure)	1,914.3	3,981.7	3,727.6
Benchmark oil price ($/Bbl)[(1)]	$50.16	$95.28	$96.96

(1) Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months were $50.16/Bbl for oil and $2.63/MMBtu for natural gas, $95.28/Bbl for oil and $4.35/MMBtu for natural gas and $96.96/Bbl for oil and $3.66/MMBtu for natural gas for the years ended December 31, 2015, 2014 and 2013, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Future operating costs, production taxes and capital costs were based on current costs as of each year-end.

There are numerous uncertainties inherent in estimating reserves and related information, and different reservoir engineers often arrive at different estimates for the same properties. There can be no assurance that our estimated net proved reserves will be produced within the periods indicated or that prices and costs will remain constant. As of February 8, 2016, the spot crude oil price was $29.71 per barrel, a 20% decrease since December 31, 2015 and a 39% decrease as compared to an average WTI of $48.75 per barrel during the year ended December 31, 2015. A further extended period of low prices for oil could result in a significant decrease in our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure in the future. Please see “Reserves sensitivity” below.

Proved undeveloped reserves

At December 31, 2015, we had approximately 70.7 MMBoe of proved undeveloped reserves as compared to 125.7 MMBoe at December 31, 2014.

The following table summarizes the changes in our proved undeveloped reserves during 2015 (in MBoe):

At December 31, 2014	125,743
Extensions, discoveries and other additions	26,278
Purchases of minerals in place	1,617
Sales of minerals in place	—
Revisions of previous estimates	(72,563)
Conversion to proved developed reserves	(10,419)
At December 31, 2015	70,656

During 2015, we spent a total of $242.4 million related to the development of proved undeveloped reserves, $105.7 million of which was spent on proved undeveloped reserves that represent wells in progress at year-end. The remaining $136.7 million resulted in the conversion of 10,419 MBoe of proved undeveloped reserves, or 8% of our proved undeveloped reserves balance at the beginning of 2015, to proved developed reserves. Our proved undeveloped reserves converted to proved developed reserves during 2015 amounted to 20% of our proved undeveloped reserves balance at the beginning of 2015 of 125,743 MBoe less our net negative revisions of previous estimates during 2015 of 72,563 MBoe. We added 26,278 MBoe of proved undeveloped reserves in the Williston Basin as a result of our 2015 operated and non-operated drilling program and anticipated five-year drilling plan. We participated in 121 gross (64.3 net) wells that were completed and brought on production during 2015. In addition, we purchased 1,617 MBoe of proved undeveloped reserves as a result of acquisitions during the year ended December 31, 2015. In 2015, our net negative revision of 72,563 MBoe, or 58% of our December 31, 2014 proved undeveloped reserves balance, is primarily due to the removal of proved undeveloped reserves that are not economic at the lower oil price or are no longer aligned with our anticipated five-year drilling plan. This resulted in 259 gross (190.8 net) proved undeveloped locations with 71,945 MBoe of reserves being removed from the December 31, 2015 estimated net proved

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reserves balance, most significantly, removing proved undeveloped reserves outside of our core acreage within the Williston Basin that were uneconomic as of December 31, 2015 due to the lower oil price.

We expect to develop all of our proved undeveloped reserves as of December 31, 2015 within five years after the initial year booked. The future development of such proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecasts as well as access to liquidity sources, such as capital markets, our revolving credit facility and derivative contracts. All proved undeveloped locations are located on properties where the leases are held by existing production or continuous drilling operations. Approximately 30% of our proved undeveloped reserves at December 31, 2015 are attributable to wells that have been drilled but not yet completed, and 100% of our undrilled reserves are within our core acreage in the Williston Basin.

Reserves sensitivity

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

This sensitivity case is only to demonstrate the impact that a lower price and cost environment may have on estimated proved reserves, PV-10 and Standardized Measure. There is no assurance that these prices or assumed cost savings will actually be achieved.

	Actual at December 31, 2015	Sensitivity Case
Oil price (per Bbl)(1)	$50.16	$35.00
Natural gas price (per MMBtu)(1)	2.63	2.00
Capital expenditure reduction	n/a	15%
Operating expense reduction	n/a	16%
Estimated proved developed reserves (MMBoe)	147.6	138.9
Estimated proved undeveloped reserves (MMBoe)	70.7	55.2
Total estimated proved reserves (MMBoe)	218.2	194.2
PV-10 (in millions)	$2,022.7	$1,164.0
Present value of future income taxes discounted at 10% (in millions)	108.4	—
Standardized Measure of discounted future net cash flows (in millions)	$1,914.3	$1,164.0

(1) Our estimated net proved reserves, PV-10 and Standardized Measure were determined using prices for oil and natural gas, without giving effect to derivative transactions, which were held constant throughout the life of the properties. The actual reserve estimates at December 31, 2015 were prepared using SEC pricing, calculated as the unweighted arithmetic average first-day-of-the-month prices for the prior twelve months, which was $50.16/Bbl for oil and $2.63/MMBtu for natural gas for the year ended December 31, 2015. The sensitivity case prices represent potential SEC pricing based on different pricing assumptions, which are in line with our budget and recent forward commodity prices for 2016. In both the actual and the sensitivity case, the prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues and PV-10 at December 31, 2015, 2014 and 2013 are based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers, by the use of appropriate geologic, petroleum engineering and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007) and definitions and current guidelines established by the SEC. DeGolyer and MacNaughton is a Delaware corporation with offices in Dallas, Houston, Calgary, Moscow and Algiers. The firm's more than 100 professionals include engineers, geologists, geophysicists, petrophysicists and economists engaged in the appraisal of oil and gas properties, evaluation of hydrocarbon and other mineral prospects, basin evaluations, comprehensive field studies and equity studies related to the domestic and international energy industry. DeGolyer and MacNaughton has provided such services for over 75 years. The Senior Vice President at DeGolyer and MacNaughton primarily responsible for overseeing the preparation of the reserve estimates is a Registered Professional Engineer in the State of Texas with over 30 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from The University of Texas at Austin in 1984, and he is a member of the International Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. DeGolyer and MacNaughton restricts its activities exclusively to consultation; it does not accept contingency fees, nor does it own operating interests in any oil, gas or mineral properties, or securities or notes of clients. The firm subscribes to a code of professional conduct, and its employees actively support their related technical and professional societies. The firm is a Texas Registered Engineering Firm.

Technology used to establish proved reserves

In accordance with rules and regulations of the SEC applicable to companies involved in oil and natural gas producing activities, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term "reasonable certainty" means deterministically, the quantities of oil and/or natural gas are much more likely to be achieved than not, and probabilistically, there should be at least a 90% probability of recovering volumes equal to or exceeding the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by using reliable technology. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Estimates of reserves were prepared by the use of appropriate geologic, petroleum engineering, and evaluation principles and techniques that are in accordance with practices generally recognized by the petroleum industry as presented in the publication of the Society of Petroleum Engineers entitled Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information (Revision as of February 19, 2007). The method or combination of methods used in the analysis of each reservoir was tempered by experience with similar reservoirs, stage of development, quality and completeness of basic data, and production history.

Based on the current stage of field development, production performance, the development plans provided by us to DeGolyer and MacNaughton and the analyses of areas offsetting existing wells with test or production data, reserves were classified as proved.

For depletion-type reservoirs or those whose performance disclosed a reliable decline in producing-rate trends or other diagnostic characteristics, reserves were estimated by the application of appropriate decline curves or other performance relationships. In the analyses of production decline curves, reserves were estimated only to the limits of economic production.

Undeveloped reserves were estimated for locations adjacent to existing wells and are based on consideration of lateral length, completion and production profiles compared by appropriate target reservoir. In certain cases, when the previously named methods could not be used, reserves were estimated by analogy with similar wells or reservoirs for which more complete data was available.

Internal controls over reserves estimation process

We employ DeGolyer and MacNaughton as the independent reserves evaluator for 100% of our reserves base. We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with the independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished for the reserves estimation process. Brett Newton, Senior Vice President of Asset Management and Chief Engineer, is the technical person primarily responsible for overseeing our reserves evaluation process. He has over 25 years of industry experience with positions of increasing responsibility in engineering and management. He holds both a Bachelor of Science degree and Master of Science degree in petroleum engineering. Mr. Newton reports directly to our President and Chief Operating Officer.

Throughout each fiscal year, our technical team meets with the independent reserve engineers to review properties and discuss evaluation methods and assumptions used in the proved reserves estimates, in accordance with our prescribed internal control procedures. Our internal controls over the reserves estimation process include verification of input data into our reserves evaluation software as well as management review, such as, but not limited to the following:

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- Comparison of historical expenses from the lease operating statements and workover authorizations for expenditure to the operating costs input in our reserves database;
- Review of working interests and net revenue interests in our reserves database against our well ownership system;
- Review of historical realized prices and differentials from index prices as compared to the differentials used in our reserves database;
- Review of updated capital costs prepared by our operations team;
- Review of internal reserve estimates by well and by area by our internal reservoir engineers;
- Discussion of material reserve variances among our internal reservoir engineers and our Senior Vice President of Asset Management and Chief Engineer;
- Review of a preliminary copy of the reserve report by our President and Chief Operating Officer with our internal technical staff; and
- Review of our reserves estimation process by our Audit Committee on an annual basis.

Production, revenues and price history

We produce and market oil and natural gas, which are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Oil supply in the United States has grown dramatically over the past few years, and this has contributed to the current global oversupply of crude oil, which has caused a sharp decline in oil prices since mid-2014. In 2015, oil inventories continued to build as global oil supply continued to outpace demand. As of February 8, 2016, the spot crude oil price was $29.71 per barrel, a 20% decrease since December 31, 2015 and a 39% decrease as compared to an average WTI of $48.75 per barrel during the year ended December 31, 2015. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. Further declines in oil and natural gas prices, extended low oil and natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets. Please see “Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Further declines, or extended current low commodity prices, in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.”

The following table sets forth information regarding our oil and natural gas production, realized prices and production costs for the periods indicated. For additional information on price calculations, please see information set forth in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

	Year Ended December 31,		
	2015	2014	2013
Net production volumes:			
Oil (MBbls)	16,091	14,883	11,133
Natural gas (MMcf)	14,002	10,691	7,450
Oil equivalents (MBoe)	18,424	16,664	12,375
Average daily production (Boe per day)	50,477	45,656	33,904
Average sales prices:			
Oil, without derivative settlements (per Bbl)(1)	$43.04	$82.73	$92.34
Oil, with derivative settlements (per Bbl)(1)(2)	66.06	83.19	91.61
Natural gas (per Mcf)(3)	2.08	6.81	6.78
Costs and expenses (per Boe of production):			
Lease operating expenses(4)	$7.84	$10.18	$7.65
Marketing, transportation and gathering expenses	1.72	1.75	2.09
Production taxes	3.78	7.66	8.12
Depreciation, depletion and amortization	26.34	24.74	24.81

General and administrative expenses	5.02	5.54	6.09

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(1) For the year ended December 31, 2013, average sales prices for oil is calculated using total oil revenues, excluding bulk oil sales of $5.8 million, divided by oil production.

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

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

(4) For the year ended December 31, 2013, lease operating expenses include midstream income and operating expenses, which are included in well services and midstream revenues and well services and midstream operating expenses, respectively, for the years ended December 31, 2015 and 2014.

Net production volumes for the year ended December 31, 2015 were 18,424 MBoe, an 11% increase from net production of 16,664 MBoe for the year ended December 31, 2014. Our net production volumes increased 1,760 MBoe over 2014 primarily due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without derivative settlements, decreased by $39.69 per barrel, or 48%, to an average of $43.04 per barrel for the year ended December 31, 2015 as compared to the year ended December 31, 2014. Giving effect to our derivative transactions in both periods, our oil sales prices decreased $17.13 per barrel to $66.06 per barrel for the year ended December 31, 2015 from $83.19 per barrel for the year ended December 31, 2014.

Net production volumes for the year ended December 31, 2014 were 16,664 MBoe, a 35% increase from net production of 12,375 MBoe for the year ended December 31, 2013. Our net production volumes increased 4,289 MBoe over 2013 due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without derivative settlements, decreased by $9.61 per barrel, or 10%, to an average of $82.73 per barrel for the year ended December 31, 2014 as compared to the year ended December 31, 2013. Giving effect to our derivative transactions in both periods, our oil sales prices decreased $8.42 per barrel to $83.19 per barrel for the year ended December 31, 2014 from $91.61 per barrel for the year ended December 31, 2013.

Productive wells

The following table presents the total and operated gross and net productive wells as of December 31, 2015:

	Total wells		Operated wells	
	Gross	Net	Gross	Net
Bakken and Three Forks	1,095	595.5	731	569.5
Other	155	93.7	101	89.3
Total wells	1,250	689.2	832	658.8

All of our productive wells are oil wells. Gross wells are the number of wells, operated and non-operated, in which we own a working interest and net wells are the total of our working interests owned in gross wells.

Acreage

The following table sets forth certain information regarding the developed and undeveloped acreage in which we own a working interest as of December 31, 2015. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Gross	Net
Developed acres	505,706	377,834
Undeveloped acres	161,231	106,911
Total acres	666,937	484,745

We increased our acreage that is held by production to 442,292 net acres at December 31, 2015 from 433,794 net acres at December 31, 2014.

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2015 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates:

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	Undeveloped acres expiring	
	Gross	Net
Year ending December 31,		
2016	30,569	16,556
2017	9,729	8,935
2018	8,378	7,938

Drilling and completion activity

The following table summarizes our completion activity for the years ended December 31, 2015, 2014 and 2013. Gross wells reflect the sum of all productive and dry wells, operated and non-operated, in which we own a working interest. Net wells reflect the sum of our working interests in gross wells. The gross and net wells represent wells completed during the periods presented, regardless of when drilling was initiated.

	Year ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	115	59.1	188	102.6	188	75.3
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total development wells	115	59.1	188	102.6	188	75.3
Exploratory wells:						
Oil	6	5.2	81	48.5	62	39.8
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	6	5.2	81	48.5	62	39.8
Total wells	121	64.3	269	151.1	250	115.1

In 2013, we focused on delineation and appraisal of the Bakken and Three Forks formations, resulting in substantially all of our acreage being delineated as of December 31, 2013. In 2014, we focused on full field development. In 2015, we continued in full field development mode with a focus on improving capital efficiency and completing more wells using high-intensity completion techniques. We also continued to participate in a number of wells on a non-operated basis.

We did not drill any dry hole wells in 2015, 2014 or 2013.

As of December 31, 2015, we had three operated rigs running, 2 gross (0.4 net) operated wells drilling, as one rig was in the process of moving to the next well, and an inventory of 85 gross operated wells waiting on completion. We expect to continue to focus on drilling with two operated rigs in the Bakken and Three Forks formations within our core acreage in 2016.

Capital expenditure budget

In 2015, we spent $610.0 million on capital expenditures, which represented a 61% decrease from the $1,572.6 million spent during 2014. This decrease was due to reduced drilling and completion activity as a result of lower commodity prices in 2015 coupled with lower well costs as a result of both improved operational efficiency and lower service costs, partially offset by higher capital expenditures for OMS, primarily related to the natural gas processing plant we are constructing in the Wild Basin area of our core acreage in North Dakota. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources—Cash flows used in investing activities.”

We have decreased our planned 2016 capital expenditures as compared to 2015 as a result of the current lower commodity prices. Our total 2016 capital expenditure budget is $400 million, which includes $237 million for exploration and production (“E&P”) capital expenditures and $163 million for non-E&P capital expenditures, including OMS, OWS, capitalized interest and administrative capital. We plan to complete approximately 46 gross (28.6 net) operated wells and participate in 0.6 net non-operated wells that are expected to be completed and brought on production in 2016. Our planned E&P capital expenditures include $200 million of drilling and completion (including production-related equipment) capital expenditures for operated and

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non-operated wells (including expected savings from services provided by OWS and OMS) and $37 million of other E&P capital expenditures. Our planned non-E&P capital expenditures include $140 million of midstream capital to continue to develop the natural gas processing plant and other infrastructure in Wild Basin and $23 million of other non-E&P capital expenditures.

While we have budgeted $400 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions, our ability to secure external funding for our Wild Basin project and the success of our drilling results as the year progresses. Additionally, if we acquire additional acreage, our capital expenditures may be higher than budgeted. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources.”

Description of properties

Our operations are focused in the North Dakota and Montana areas of the Williston Basin. While we have interests in a substantial number of wells in the Williston Basin that target several different zones, our development activities are currently concentrated in the Bakken and Three Forks formations. Our management team originally targeted the Williston Basin because of its oil-prone nature, multiple producing horizons, substantial resource potential and management’s previous professional history in the basin. The Williston Basin also generally has established infrastructure and access to materials and services.

The entire Williston Basin is spread across North Dakota, South Dakota, Montana and parts of southern Canada. The basin produces oil and natural gas from numerous producing horizons including, but not limited to, the Bakken, Three Forks, Madison and Red River formations. A report issued by the United States Geological Survey in April 2008 classified these formations as the largest continuous oil accumulation ever assessed by it in the contiguous United States. The Williston Basin has recently been one of the most actively drilled unconventional oil resource plays in the United States, reaching over 200 rigs drilling in the basin in 2014, although the active rig count decreased throughout 2015 due to low oil prices and fell to fewer than 50 rigs drilling in the basin in early 2016. Most rigs that are running in the Williston Basin are focused on drilling areas with the highest estimated ultimate recoveries that have attractive economics even in depressed oil price environments. Our development activity is focused in the deepest part of the Williston Basin, which we call the core.

The Devonian-age Bakken formation is found within the Williston Basin underlying portions of North Dakota and Montana and is comprised of three lithologic members including the upper shale, middle Bakken and lower shale. The formation ranges up to 150 feet thick. The upper and lower shales are highly organic, thermally mature and over pressured and can act as both a source and reservoir for the oil. The middle Bakken, which varies in composition from a silty dolomite to shaley limestone or sand, also serves as a reservoir and is a critical component for commercial production. Generally, the Bakken formation is found at vertical depths of 8,500 to 11,500 feet. Based on our geologic interpretation of the Bakken formation, the evolution of completion techniques, our own drilling results and publicly available drilling results for other operators in the basin, we believe that a substantial portion of our Williston Basin acreage is prospective in the Bakken formation.

The Three Forks formation, generally found immediately under the Bakken formation, has also proven to contain productive reservoir rock. The Three Forks formation typically consists of interbedded dolomites and shale with local development of a discontinuous sandy member at the top, known as Sanish sand. The Three Forks formation is an unconventional carbonate play. Based on our geologic interpretation of the Three Forks formation, the evolution of completion techniques, our own drilling results and publicly available drilling results for other operators in the basin, we believe that much of our Williston Basin acreage is prospective in the Three Forks formation.

Our total leasehold position in the Williston Basin as of December 31, 2015 consisted of 484,745 net acres. Our estimated net proved reserves in the Williston Basin were 218.2 MMBoe at December 31, 2015. Of our estimated net proved reserves in the Williston Basin, approximately 147.6 MMBoe were proved developed reserves, which are comprised of a combination of wells drilled to conventional reservoirs, Bakken and Three Forks wells drilled with older completion techniques, and to a much larger extent, Bakken and Three Forks wells drilled with completion techniques similar to those we currently employ. Of our estimated net proved reserves, 70.7 MMBoe were proved undeveloped reserves, all of which consisted of Bakken and Three Forks wells to be drilled with more recent completion techniques, although our proved undeveloped reserves do not incorporate the impact of high intensity completion techniques. As of December 31, 2015, we had a total of 689.2 net operated and non-operated producing wells and 658.8 net operated producing wells in the Williston Basin. We had average daily production of 50,477 net Boe per day for the year ended December 31, 2015 in the Williston Basin. During 2015, our Bakken and Three Forks wells produced a daily average of 49,788 net Boe per day with 595.5 net producing wells on December 31, 2015. Accordingly, our 595.5 net Bakken and Three Forks wells were responsible for 99% of our average daily production during 2015. As of December 31, 2015, our working interest for all producing wells averaged 56% and in the wells we operate was approximately 79%. As of December 31, 2015, we had 117 gross (63.8 net) wells in the process of being drilled or completed in the Williston Basin, which includes 2 gross operated wells drilling, 85 gross operated wells waiting on completion and 30

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gross non-operated wells drilling or completing. We participated in 121 gross (64.3 net) wells that were completed and brought on production during 2015.

Marketing, transportation and major customers

The Williston Basin crude oil rail and pipeline transportation and refining infrastructure has grown substantially in recent years, largely in response to drilling activity in the Bakken and Three Forks formations. In December 2015, oil production in North Dakota was approximately 1,152,000 barrels per day. According to the North Dakota Pipeline Authority website's data last updated January 15, 2016, there was approximately 827,000 barrels per day of crude oil pipeline transportation capacity and approximately 1,490,000 barrels per day of specifically dedicated rail loading capacity in the Williston Basin as of December 31, 2015. In 2015, we continued to sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which typically originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of December 31, 2015, we were flowing over 80% of our gross operated oil production through these gathering systems.

Crude oil produced and sold in the Williston Basin has historically sold at a discount to WTI due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. Expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the first quarter of 2015, as WTI declined, our price differentials increased as a percentage of WTI to a 16% discount but decreased in terms of the dollar per barrel discount to WTI to an average of $7.85 per barrel of oil. In the second quarter of 2015, as WTI improved, our price differentials decreased to approximately 10% as a percentage of WTI and continued to decrease in terms of the dollar per barrel discount to WTI to an average of $5.90 per barrel of oil. In the second half of 2015, while WTI fell again, our price differentials strengthened, decreasing to less than $5.00 per barrel of oil and remaining at approximately 10% as a percentage of WTI. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations. For a discussion of the potential risks to our business that could result from transportation and refining infrastructure constraints in the Williston Basin, please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices."

We principally sell our oil and natural gas production to refiners, marketers and other purchasers that have access to nearby pipeline and rail facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. For a description of some of these factors, please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production" and "Risk Factors—Risks related to the oil and natural gas industry and our business—Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices." At the end of 2015, the U.S. government lifted the long-standing ban on crude oil exports. While we believe this could have a positive impact on the long-term value of Bakken crude oil, current market conditions are not expected to result in sizeable quantities of U.S. crude oil being exported out of the country.

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. As of December 31, 2015, we sold a substantial majority of our oil and condensate through bulk sales at delivery points on crude oil gathering systems or directly at the wellhead to a variety of purchasers at prevailing market prices under short-term contracts that normally provide for us to receive a market-based price, which incorporates regional differentials that include, but are not limited to, transportation costs and adjustments for product quality. We also entered into various short-term sales contracts for a portion of our portfolio at fixed 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.

For the year ended December 31, 2015, sales to Shell Trading (US) Company accounted for approximately 10% of our total sales. For the years ended December 31, 2014 and 2013, sales to Musket Corporation accounted for approximately 13% and 11% of our total sales, respectively. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2015, 2014 and 2013. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil and natural gas purchasers in the Williston Basin.

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Since most of our oil and natural gas production is sold under market-based or spot market contracts, the revenues generated by our operations are highly dependent upon the prices of and demand for oil and natural gas. The price we receive for our oil and natural gas production depends upon numerous factors beyond our control, including but not limited to seasonality, weather, competition, availability of transportation and gathering capabilities, worldwide and regional economic conditions, global and domestic oil supply, foreign imports, political conditions in other oil-producing and natural gas-producing regions, the actions of the Organization of Petroleum Exporting Countries, or OPEC, and domestic government regulation, legislation and policies. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Further declines, or extended current low commodity prices, in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments." Furthermore, a decrease in the price of oil and natural gas could have an adverse effect on the carrying value of our estimated proved reserves and on our revenues, profitability and cash flows. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may be required to take write-downs of the carrying values of our oil and natural gas properties."

Market, economic, transportation and regulatory factors may in the future materially affect our ability to market our oil or natural gas production. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production."

Competition

The oil and natural gas industry is worldwide and highly competitive in all phases. We encounter competition from other oil and natural gas companies in all areas of operation, including the acquisition of leasing options on oil and natural gas properties to the exploration and development of those properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well established companies that have substantially larger operating staffs and greater capital resources than we do. Such companies may be able to pay more for lease options on oil and natural gas properties and exploratory locations and to define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit. Our ability to acquire additional properties and to discover reserves in the future will depend upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel."

Title to properties

As is customary in the oil and gas industry, we initially conduct a preliminary review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant title defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with general industry standards. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of the properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our revolving credit facility, liens for current taxes and other burdens, which we believe do not materially interfere with the use or affect our carrying value of the properties. Please see "Item 1A. Risk Factors—Risks related to the oil and natural gas industry and our business—We may incur losses as a result of title defects in the properties in which we invest."

Seasonality

Winter weather conditions and lease stipulations can limit or temporarily halt our drilling, completion and producing activities and other oil and natural gas operations. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Regulation of the oil and natural gas industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations, such laws and regulations are frequently amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (“FERC”) and the courts. We cannot predict when or whether any such proposals may become effective.

Regulation of transportation of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil by common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil pipelines that allows a pipeline to increase its rates annually up to a prescribed ceiling, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index level in relation to changes in industry costs. Most recently, on December 16, 2010, the FERC established a new price index for the five-year period beginning July 1, 2011.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is generally governed by prorationing provisions set forth in the pipelines’ published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

We sell a significant amount of our crude oil production through gathering systems connected to rail facilities. Several derailments of freight trains, including the events in July 2013 in Lac Mégantic, have led federal and state regulators to examine whether the hazardous nature of crude oil from the Bakken shale is being assessed properly prior to its shipment. In particular, there are concerns that the testing and ensuing designations of the crude oil on the shipping documentation do not in all cases accurately capture the flammability of the Bakken crude oil. On January 2, 2014, the Pipeline and Hazardous Materials Safety Administration (“PHMSA”) released a Safety Alert alerting regulators, emergency responders, transporters and shippers that crude oil from the Bakken Shale may have flammability characteristics that are different from other forms of crude oil and that it was vital that all shipments of crude oil be tested and properly characterized on all shipping documentation. The Safety Alert also notified the regulated community that PHMSA and the Federal Railroad Administration have launched "Operation Classification," which is an ongoing enforcement initiative that involves unannounced inspections on crude oil shipments to test the contents of the shipments in order to ensure that they are properly characterized. In August 2014, the U.S. Department of Transportation released a report finding that, based on the results of Operation Classification from August 2013

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to May 2014, Bakken crude oil tends to be more volatile and flammable than other crude oils, and thus poses an increased risk for a significant accident.

In addition, these events have also spurred efforts to improve the safety of tank cars that are used in transporting crude oil by rail. Since 2011, all new railroad tank cars that have been built to transport crude oil or other petroleum type fluids (e.g., ethanol) have been built to more stringent safety standards. In May 2015, PHMSA adopted a final rule that, among other things, imposes a new and enhanced tank car design standard for certain tank cars carrying crude oil and ethanol, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also includes new operational requirements such as routing analyses, speed restrictions and enhanced braking controls. Safety improvements or updates to existing tank cars that are imposed under the May 2015 PHMSA final rule could drive up the cost of transport and lead to shortages in availability of tank cars. We do not currently own or operate rail transportation facilities or rail cars; however, we cannot assure that costs incurred by the railroad industry to comply with these enhanced standards resulting from PHMSA's final rule will not increase our costs of doing business or limit our ability to transport and sell our crude oil at favorable prices, the consequences of which could be material to our business, financial condition or results of operations. However, we believe that any such consequences would not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Efforts are likewise underway in Canada to assess and address risks from the transport of crude oil by rail. Shortly after the Lac Mégantic tragedy, Transport Canada issued a series of emergency directives aimed at certain practices that were identified immediately after the accident. Likewise, Transport Canada is assessing the compensation and liability scheme for shipments by rail so that sufficient funds are available to compensate victims and respond to the incident without making taxpayers fund any aspect of those efforts. Transport Canada has also issued recent legal requirements that align with the U.S. May 2015 PHMSA final rule in many respects. In January 2014, the Canadian Transportation Safety Board made several recommendations to Transport Canada regarding tank car safety, routing of freight trains and the capabilities of emergency responders. In April 2014, Transport Canada issued a protective order prohibiting oil shippers from using 5,000 of the DOT-111 tank cars and imposing a phase out for tank cars that do not meet certain safety requirements by as early as May 2017. Transport Canada also imposed a 50 mile-per-hour speed limit on trains carrying hazardous materials and required all crude oil shipments in Canada to have an emergency response plan.

We believe we are in substantial compliance with applicable hazardous materials transportation requirements related to our operations. We do not believe that compliance with federal, state or local hazardous materials transportation regulations will have a material adverse effect on our financial position or results of operations. However, future events, such as changes in existing laws (including changes in the interpretation of existing laws), the promulgation of new laws and regulations, including any voluntary measures introduced by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport crude oil, or the development or discovery of new facts or conditions could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices, the consequences of which could be material to our business, financial condition or results of operations. However, we believe that any such consequences would not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA") and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

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In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC under Order No. 637 will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC") and the Federal Trade Commission ("FTC"). Please see below the discussion of "Other federal laws and regulations affecting our industry—Energy Policy Act of 2005." Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities. In addition, pursuant to Order No. 704, some of our operations may be required to annually report to FERC on May 1 of each year for the previous calendar year. Order No. 704 requires certain natural gas market participants to report information regarding their reporting of transactions to price index publishers and their blanket sales certificate status, as well as certain information regarding their wholesale, physical natural gas transactions for the previous calendar year depending on the volume of natural gas transacted. Please see below the discussion of "Other federal laws and regulations affecting our industry—FERC market transparency rules."

Gathering services, which occur upstream of FERC jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own and operate properties in North Dakota and Montana, which have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, both states impose a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within their jurisdictions.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Other federal laws and regulations affecting our industry

Energy Policy Act of 2005. On August 8, 2005, President Bush signed into law the Energy Policy Act of 2005 (“EPAct 2005”). EPAct 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, EPAct 2005 amends the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. EPAct 2005 provides the

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FERC with the power to assess civil penalties of up to $1 million per day for violations of the NGA and increases the FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1 million per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, to (1) use or employ any device, scheme or artifice to defraud; (2) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) engage in any act, practice or course of business that operates as a fraud or deceit upon any person. The new anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, as described below. The anti-manipulation rules and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority. Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

FERC market transparency rules. On December 26, 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order No. 704. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the FTC issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale from: (a) knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person; or (b) intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

North Dakota Industrial Commission oil and gas rule changes. The North Dakota Industrial Commission ("NDIC") has adopted more stringent rule changes to its existing oil and gas regulations. The rules became effective on April 1, 2012 and, among other things, impose relatively higher bonding amounts for the drilling of wells, severely restrict the discharge and storage of production wastes such as produced water, drilling mud, waste oil and other wastes in earthen pits, implement more stringent hydraulic fracturing requirements and require the provision of public disclosure on the national website, FracFocus.org, regarding chemicals used in the hydraulic fracturing process. Compliance with these recent rule changes by oil and natural gas exploration and production operators in general and us in particular increased our well costs from 2012 to 2015, and we expect to continue to incur these increased costs in order to remain in compliance.

In 2014, the NDIC adopted an order intended to reduce natural gas flaring, which order was subsequently modified in late 2015. Please see below the discussion of "Environmental protection and natural gas flaring initiatives." In addition, on December 9, 2014, the NDIC adopted new conditioning standards to improve the safety of Bakken crude oil for transport. The rule became effective April 1, 2015 and sets operating standards for conditioning equipment to properly separate production fluids. The rule includes parameters for temperatures and pressures for production equipment. The

rule also addresses limits to vapor pressure of produced crude oil.
Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Environmental and occupational health and safety regulation

Our exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct

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exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment; limit or prohibit construction or drilling activities in environmentally-sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered species; require investigatory and remedial actions to mitigate pollution conditions; impose obligations to reclaim and abandon well sites and pits; and impose specific criteria addressing worker protection. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays in the development of projects and the issuance of orders enjoining some or all of our operations in affected areas. These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in federal or state environmental laws and regulations or reinterpretation of applicable enforcement policies that result in more stringent and costly well construction, drilling, water management or completion activities, or waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial position. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third-party claims for damage to property, natural resources or persons. While we believe that we are in substantial compliance with existing environmental laws and regulations and that continued compliance with current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that we will be able to remain in compliance in the future with such existing or any new laws and regulations or that such future compliance will not have a material adverse effect on our business and operating results.

The following is a summary of the more significant existing environmental and occupational health and safety laws, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and wastes

The Comprehensive Environmental Response, Compensation, and Liability Act (“CERCLA”), also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a “hazardous substance” into the environment. These classes of persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances released at the site. Under CERCLA, these “responsible persons” may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency (“EPA”) and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We are also subject to the requirements of the Resource Conservation and Recovery Act (“RCRA”) and comparable state statutes. RCRA imposes strict requirements on the generation, storage, treatment, transportation, disposal and cleanup of hazardous and nonhazardous wastes. Under the authority of the EPA, most states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. RCRA currently exempts certain drilling fluids, produced waters and other wastes associated with exploration, development and production of oil and natural gas from regulation as hazardous wastes. These wastes, instead, are regulated under RCRA’s less stringent nonhazardous waste provisions, state laws or other federal laws. However, it is possible that certain oil and natural gas exploration, development and production wastes now classified as nonhazardous wastes could be classified as hazardous wastes in the future. For example, in August 2015, several non-governmental organizations filed notice of intent to sue the EPA under RCRA for, among other things, the agency's alleged failure to reconsider whether such exclusion should continue to apply. Repeal or modification of this RCRA exclusion or similar exemptions under state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the oil and natural gas industry in general. In the course of our operations, we generate ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons, hazardous substances and wastes may have been released on, under or from the properties owned or leased by us or on, under or from, other locations where these petroleum hydrocarbons and wastes have been taken for recycling or disposal. In addition, certain of these properties have been operated by the third parties whose treatment and disposal or release of petroleum hydrocarbons, hazardous substances and wastes were not under our control. These properties and the substances disposed or released thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including contaminated groundwater) and to perform remedial plugging or pit closure operations to prevent future contamination.

Air emissions

The federal Clean Air Act ("CAA") and comparable state laws and regulations restrict the emission of various air pollutants from many sources through air emissions standards, construction and operating permitting programs, and the imposition of other monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Obtaining permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions-related issues. For example, in October 2015, the EPA issued a final rule under the CAA, lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion under both the primary and secondary standards to provide requisite protection of public health and welfare, respectively. We review new rules such as this one to assess their impact on our operations. Compliance with this final rule or any other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Environmental protection and natural gas flaring initiatives

We attempt to conduct our operations in a manner that protects the health, safety and welfare of the public, our employees and the environment. We are focused on the reduction of air emissions produced from our operations, particularly with respect to flaring of natural gas from our operated well sites. The rapid growth of crude oil production in North Dakota in recent years, coupled with a historical lack of natural gas gathering infrastructure in the state, has led to efforts to reduce flaring of natural gas produced in association with crude oil production. We recognize the environmental and financial risks associated with natural gas flaring, and we seek to manage these risks on an ongoing basis and reduce flaring from our operated well sites.

We believe that one of the leading causes of natural gas flaring from the Bakken and Three Forks formations is the inability of operators to promptly connect their wells to natural gas processing and gathering infrastructure due to external factors out of the control of the operator, such as, for example, the granting of right-of-way access by land owners, investment from third parties in the development of gas gathering systems and processing facilities, and the development and adoption of regulations. However, we have allocated significant resources to connect our Bakken and Three Forks wells to natural gas infrastructure in a timely manner to reduce our flared volumes. We have exceeded a goal that we voluntarily set in 2014 to maintain well connections for an average of 90% of our operated Bakken and Three Forks wells, by having approximately 98% and 97% of our operated Bakken and Three Forks wells connected to gathering systems as of December 31, 2015 and 2014, respectively. We believe that achieving this goal helps us to minimize our flared volumes of natural gas.

On July 1, 2014, the NDIC adopted Order No. 24665 (the "July 2014 Order"), pursuant to which the agency adopted legally enforceable "gas capture percentage goals" targeting the capture of 74% of natural gas produced in the state by October 1, 2014, 77% of such gas by January 1, 2015, 85% of such gas by January 1, 2016 and 90% of such gas by October 1, 2020. Modification of the July 2014 Order was announced by the NDIC in the fourth quarter of 2015, resulting in the existing January 1, 2015 gas capture rate of 77% being extended to April 1, 2016 and updated gas capture rates of 80% by April 1, 2016, 85% by November 1, 2016, 88% by November 1, 2018 and 91% by November 1, 2020. The July 2014 Order established an enforcement mechanism for policy recommendations that were previously adopted by the NDIC in March 2014. Those recommendations required all exploration and production operators applying for new drilling permits in the state after June 1, 2014 to develop Gas Capture Plans that provide measures for reducing the amount of natural gas flared by those operators so as to be consistent with the agency's gas capture percentage goals. In particular, the July 2014 Order provided that after an initial 90-day period, wells must meet or exceed the NDIC's gas capture percentage goals on a per-well, per-field, county or statewide basis. Failure to comply with the gas capture percentage goals will result in an operator having to restrict its production to 200 barrels of oil per day if at least 60% of the monthly volume of associated natural gas produced from the well is captured, or 100 barrels of oil per day if less than 60% of such monthly volume of natural gas is captured. As of December 31, 2015, we were capturing approximately 91% of our natural gas production in North Dakota. While we were in compliance with these requirements as of December 31, 2015 and expect to remain in compliance in the future, there is no assurance that we will be able to remain in compliance in the future or that such future compliance will not have a material adverse effect on our business and operation results.

Climate change

The EPA has determined that emissions of carbon dioxide, methane and other greenhouse gases (“GHG”) present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the Earth’s atmosphere and other climatic changes. In response to this determination, the EPA adopted regulations under existing provisions of the CAA that establish Prevention of Significant Deterioration (“PSD”) construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards, which typically will be established by the states. These EPA rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, oil and natural gas production facilities, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While from time to time Congress has considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. The adoption of any new legislation or regulations that requires reporting of GHGs or otherwise restricts emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production activities, as part of an overall effort to reduce methane emissions by up to 45% in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how new methane restrictions would impact the our business or how or when the United States might impose restrictions on GHGs as a result of the international agreement agreed to in Paris.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Water discharges

The Federal Water Pollution Control Act (the “Clean Water Act”) and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters and waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. The EPA released a final rule in May 2015 that attempted to clarify federal jurisdiction under the Clean Water Act over waters of the United States, but a number of legal challenges to this rule are pending, and implementation of the rule has been stayed nationwide. To the extent this rule expands the scope of the Clean Water Act's jurisdiction, drilling programs could incur increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas.

The Oil Pollution Act of 1990 ("OPA") amends the Clean Water Act, and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities and onshore facilities, including exploration and

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production facilities that may affect waters of the United States. Under the OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Operations associated with our production and development activities generate drilling muds, produced waters and other waste streams, some of which may be disposed of by means of injection into underground wells situated in non-producing subsurface formations. The NDIC rule changes effective in 2012 severely restrict the discharge and storage of production wastes including produced water in earthen pits, which increases the likelihood that injection wells are used to dispose of appropriate waste streams. These injection wells are regulated by the federal Safe Drinking Water Act and analogous state laws. The underground injection well program under the Safe Drinking Water Act requires permits from the EPA or analogous state agency for disposal wells that we operate, establishes minimum standards for injection well operations and restricts the types and quantities of fluids that may be injected. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages and personal injuries. Moreover, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations, which costs could be significant. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Hydraulic fracturing activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from unconventional formations, including shales. The process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA issued CAA final regulations in 2012 and proposed additional CAA regulations in August 2015 governing performance standards for the oil and natural gas industry; proposed in April 2015 effluent limitations guidelines that waste water from shale natural gas extraction operations must meet before discharging to a treatment plant; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management (“BLM”) published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups. From time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. In addition, some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, following the lead of the State of New York in 2015. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. Nevertheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources in June 2015, which report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA's Science Advisory Board provided its comments on the draft study, indicating its concern that the EPA's conclusion of no widespread, systemic impacts

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on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Please see “Item 1A. Risk Factors—We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.”

Endangered Species Act considerations

The federal Endangered Species Act (“ESA”) may restrict exploration, development and production activities that may affect endangered and threatened species or their habitats. The ESA provides broad protection for species of fish, wildlife and plants that are listed as threatened or endangered in the United States and prohibits the taking of endangered species. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Federal agencies are required to ensure that any action authorized, funded or carried out by them is not likely to jeopardize the continued existence of listed species or modify their critical habitats. Some of our facilities may be located in areas that are designated as habitat for endangered or threatened species. If endangered or threatened species are located in areas of the underlying properties where we wish to conduct seismic surveys, development activities or abandonment operations, such work could be prohibited or delayed or expensive mitigation may be required. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in 2011, the U.S. Fish and Wildlife Service is required to make a determination on a listing of numerous species as endangered or threatened under the ESA by no later than completion of the agency’s 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in delays or limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves.

Operations on federal lands

Performance of oil and gas exploration and production activities on federal lands, including Indian lands and lands administered by the federal BLM are subject to the National Environmental Policy Act (“NEPA”). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Depending on any mitigation strategies recommended in such environmental assessments or environmental impact statements, we could incur added costs, which could be substantial, and be subject to delays or limitations in the scope of oil and natural gas projects. Authorizations under NEPA are also subject to protest, appeal or litigation, any or all of which may delay or halt our exploration and production activities.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act (“OSHA”) and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens.

Employees

As of December 31, 2015, we employed 535 people. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Offices

As of December 31, 2015, we leased 111,628 square feet of office space in Houston, Texas at 1001 Fannin Street, where our principal offices are located. The lease for our Houston office expires in September 2020. We also own field offices in the North Dakota communities of Williston, Powers Lake and Alexander.

Available information

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We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Our filings with the SEC are also available to the public from commercial document retrieval services and at the SEC's website at http://www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange ("NYSE") under the symbol "OAS." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

We also make available on our website at http://www.oasispetroleum.com all of the documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K.

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Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10-K, actually occurs, our business, financial condition or results of operations could suffer. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect us.

Risks related to the oil and natural gas industry and our business

Further declines, or extended current low commodity prices, in oil and, to a lesser extent, natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. For example, average daily prices for WTI crude oil ranged from a high of $61.36 per barrel to a low of $34.55 per barrel during 2015. Average daily prices for NYMEX Henry Hub natural gas ranged from a high of $3.32 per MMBtu to a low of $1.63 per MMBtu during 2015. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America, China, India and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and regional, domestic and international transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors’ supplies of oil and natural gas;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Substantially all of our production is sold to purchasers under short-term (less than twelve-month) contracts at market-based prices. Low oil and natural gas prices will reduce our cash flows, borrowing ability, the present value of our reserves and our ability to develop future reserves. See “Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our estimated net oil and natural gas reserves” below. Low oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves. See also “The present value of future net revenues from our estimated net proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves” below.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned operating results.

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We may not be able to generate enough cash flow to meet our debt obligations.

We expect our earnings and cash flow to vary significantly from year to year due to the nature of our industry. As a result, the amount of debt that we can manage in some periods may not be appropriate for us in other periods. Additionally, our future cash flow may be insufficient to meet our debt obligations and other commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and to pay our debt obligations. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy and initiatives of our competitors, are beyond our control. If we do not generate enough cash flow from operations to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

- selling assets;
- reducing or delaying capital investments;
- seeking to raise additional capital; or
- refinancing or restructuring our debt.

If for any reason we are unable to meet our debt service and repayment obligations, we would be in default under the terms of the agreements governing our debt, which would allow our creditors at that time to declare all outstanding indebtedness to be due and payable, which would in turn trigger cross-acceleration or cross-default rights between the relevant agreements. In addition, our lenders could compel us to apply all of our available cash to repay our borrowings or they could prevent us from making payments on our senior unsecured notes. If amounts outstanding under our revolving credit facility or our senior unsecured notes were to be accelerated, we cannot be certain that our assets would be sufficient to repay in full the money owed to the lenders or to our other debt holders. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources.”

Our revolving credit facility and the indentures governing our senior unsecured notes all contain operating and financial restrictions that may restrict our business and financing activities.

Our revolving credit facility and the indentures governing our senior unsecured notes contain a number of restrictive covenants that impose significant operating and financial restrictions on us, including restrictions on our ability to, among other things:

- sell assets, including equity interests in our subsidiaries;
- pay distributions on, redeem or repurchase our common stock or redeem or repurchase our debt;
- make investments;
- incur or guarantee additional indebtedness or issue preferred stock;
- create or incur certain liens;
- make certain acquisitions and investments;
- redeem or prepay other debt;
- enter into agreements that restrict distributions or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates;
- create unrestricted subsidiaries;
- enter into sale and leaseback transactions; and
- engage in certain business activities.

As a result of these covenants, we are limited in the manner in which we conduct our business, and we may be unable to engage in favorable business activities or finance future operations or capital needs.

Our ability to comply with some of the covenants and restrictions contained in our revolving credit facility and the indentures governing our senior unsecured notes may be affected by events beyond our control. If market or other economic conditions deteriorate or if oil and natural gas prices remain at their current level for an extended period of time or continue to decline, our ability to comply with these covenants may be impaired. A failure to comply with the covenants, ratios or tests in our revolving credit facility, the indentures governing our senior unsecured notes or any future indebtedness could result in an event of default under our revolving credit facility, the indentures governing our senior unsecured notes or our future indebtedness, which, if not cured or waived, could have a material adverse effect on our business, financial condition and results of operations.

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If an event of default under our revolving credit facility occurs and remains uncured, the lenders thereunder:

- would not be required to lend any additional amounts to us;
- could elect to declare all borrowings outstanding, together with accrued and unpaid interest and fees, to be due and payable;
- may have the ability to require us to apply all of our available cash to repay these borrowings; or
- may prevent us from making debt service payments under our other agreements.

A payment default or an acceleration under our revolving credit facility could result in an event of default and an acceleration under the indentures for our senior unsecured notes. If the indebtedness under the notes were to be accelerated, there can be no assurance that we would have, or be able to obtain, sufficient funds to repay such indebtedness in full. In addition, our obligations under our revolving credit facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 90% of the reserve value as determined by reserve reports, and if we are unable to repay our indebtedness under the revolving credit facility, the lenders could seek to foreclose on our assets. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources."

Our level of indebtedness may increase and reduce our financial flexibility.

As of December 31, 2015, we had $138.0 million of outstanding borrowings and had $5.2 million of outstanding letters of credit under our revolving credit facility, $1,144.8 million available for future secured borrowings under our revolving credit facility including pro forma adjustments for the current borrowing base and the net proceeds from our public equity offering in February 2016 and $2,200.0 million outstanding in senior unsecured notes. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources—Senior secured revolving line of credit" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and capital resources—Senior unsecured notes." In the future, we may incur significant indebtedness in order to make future acquisitions or to develop our properties.

Our level of indebtedness could affect our operations in several ways, including the following:

- a significant portion of our cash flows could be used to service our indebtedness;
- a high level of debt would increase our vulnerability to general adverse economic and industry conditions;
- the covenants contained in the agreements governing our outstanding indebtedness limit our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- our debt covenants may also affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- a high level of debt may place us at a competitive disadvantage compared to our competitors that are less leveraged and therefore, may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- a high level of debt may make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then-outstanding bank borrowings; and
- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control. If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may not be able to generate sufficient cash flows to pay the interest on our debt and future working capital, and borrowings or equity financing may not be available to pay or refinance such debt. Factors that will affect our ability to raise cash through an offering of our capital stock or a refinancing of our debt include financial market conditions, the value of our assets and our performance at the time we need capital.

In addition, our bank borrowing base is subject to periodic redeterminations. We could be forced to repay a portion of our bank borrowings due to redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are otherwise unable to negotiate renewals of our borrowings or arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

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Our derivative activities could result in financial losses or could reduce our income.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contract obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual price received.

In addition, some of these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas and may expose us to cash margin requirements.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit drilling locations or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "Our estimated net proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves" below. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of or delays in obtaining equipment and qualified personnel;
- facility or equipment malfunctions and/or failure;
- unexpected operational events, including accidents;
- pressure or irregularities in geological formations;
- adverse weather conditions, such as blizzards, ice storms and floods;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;
- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.

Our estimated net proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. See "Item 1. Business—Our operations" for information about our estimated oil and natural gas reserves and the PV-10 and Standardized Measure of discounted future net revenues as of December 31, 2015, 2014 and 2013.

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In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Although the reserve information contained herein is reviewed by our independent reserve engineers, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this Annual Report on Form 10-K. In addition, we may adjust estimates of net proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control. Due to the limited production history of our undeveloped acreage, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

The present value of future net revenues from our estimated net proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our estimated net proved reserves is the current market value of our estimated net oil and natural gas reserves. In accordance with SEC requirements for the years ended December 31, 2015, 2014 and 2013, we based the estimated discounted future net revenues from our estimated net proved reserves on the twelve-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from estimated net proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this Annual Report on Form 10-K. Any significant future price changes will have a material effect on the quantity and present value of our estimated net proved reserves.

If oil and natural gas prices remain at their current level for an extended period of time or continue to decline, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. In addition, we assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our revolving credit facility. A write-down constitutes a non-cash charge to earnings. The continued decline in oil and natural gas prices since December 31, 2015 may cause us to incur impairment charges in the future, which could have a material adverse effect on our ability to borrow under our revolving credit facility and our results of operations for the periods in which such charges are taken. Due to lower expected future oil prices, we reviewed our proved oil and natural gas properties for impairment as of December 31, 2015 and 2014. For the year ended December 31, 2015, we recorded an impairment loss of $9.4 million to adjust the carrying value of our proved oil and natural gas properties held for sale to their estimated fair value. For the year ended December 31, 2014, we determined that the carrying value exceeded expected undiscounted cash flows for certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations. As a result, we recorded an impairment loss of $40.0 million to adjust the carrying amount of these assets to fair value. No impairment on proved oil and natural gas properties was recorded for the year ended December 31, 2013. During the years ended December 31, 2015, 2014 and 2013, we recorded non-cash impairment charges of $36.6 million, $7.3 million and $1.2 million, respectively, on our unproved properties due to expiring leases and periodic assessments of our unproved properties.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services or the unavailability of sufficient transportation for our production could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services or the unavailability of sufficient transportation for our production could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations. Additionally, compliance with new or emerging legal requirements that affect midstream operations in North Dakota may reduce the availability of transportation for our production. For example, the NDIC adopted regulations in late 2013 that impose more rigorous pipeline development standards on midstream operators, some of whom we rely on to construct and operate pipeline infrastructure to transport the oil and natural gas we produce.

Part of our strategy involves drilling in existing or emerging shale plays using some of the latest available horizontal drilling and completion techniques. The results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production. As a result, we may incur material write-downs and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Operations in the Bakken and the Three Forks formations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations, successfully cleaning out the well bore after completion of the final fracture stimulation stage and successfully protecting nearby producing wells from the impact of fracture stimulation.

Our experience with horizontal drilling utilizing the latest drilling and completion techniques specifically in the Bakken and Three Forks formations began in late 2009. Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or oil and natural gas prices decline, the return on our investment in these areas may not be as attractive as we anticipate. We could incur material write-downs of unevaluated properties, and the value of our undeveloped acreage could decline in the future.

Our exploration, development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to expiration of our leases or a decline in our estimated net oil and natural gas reserves.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. We spent $610.0 million and $1,572.6 million related to capital expenditures for the years ended December 31, 2015 and 2014, respectively. Our capital expenditure budget for 2016 is approximately $400 million, with approximately $200 million allocated for drilling and completion operations. Since our initial public offering, our capital expenditures have been financed with proceeds from public equity offerings, proceeds from our $2,200.0 million of senior unsecured notes, borrowings under our revolving credit facility, net cash provided by operating activities, the sale of non-core oil and gas properties and cash settlements of derivative contracts. DeGolyer and MacNaughton projects that we will incur capital costs of $828.6 million over the next five years to develop the proved undeveloped reserves in the Williston Basin covered by its December 31, 2015 reserve report. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

A significant increase in product prices could result in an increase in our capital expenditures. We intend to finance our future capital expenditures primarily through cash flows provided by operating activities, borrowings under our revolving credit facility and cash settlements of derivative contracts; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of additional debt or equity securities or the sale of non-strategic assets. The issuance of additional debt or equity may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital

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expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. In addition, upon the issuance of certain debt securities (other than on a borrowing base redetermination date), our borrowing base under our revolving credit facility will be automatically reduced by an amount equal to 25% of the aggregate principal amount of such debt securities.

Our cash flows provided by operating activities and access to capital are subject to a number of variables, including:

- our estimated net proved reserves;
- the level of oil and natural gas we are able to produce from existing wells and new projected wells;
- the prices at which our oil and natural gas are sold;
- the costs of developing and producing our oil and natural gas production;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of our banks to lend; and
- our ability to access the equity and debt capital markets.

If the borrowing base under our revolving credit facility or our revenues decrease as a result of low oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our drilling locations, which in turn could lead to a possible expiration of our leases and a decline in our estimated net proved reserves, and could adversely affect our business, financial condition and results of operations.

We will not be the operator on all of our drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We may enter into arrangements with respect to existing or future drilling locations that result in a greater proportion of our locations being operated by others. As a result, we may have limited ability to exercise influence over the operations of the drilling locations operated by our partners. Dependence on the operator could prevent us from realizing our target returns for those locations. The success and timing of exploration and development activities operated by our partners will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator’s expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

This limited ability to exercise control over the operations of some of our drilling locations may cause a material adverse effect on our results of operations and financial condition.

All of our producing properties and operations are located in the Williston Basin region, making us vulnerable to risks associated with operating in one major geographic area.

As of December 31, 2015, 100% of our proved reserves and production were located in the Williston Basin in northwestern North Dakota and northeastern Montana. As a result, we may be disproportionately exposed to the impact of economics in the Williston Basin or delays or interruptions of production from these wells caused by transportation capacity constraints, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions, plant closures for scheduled maintenance or interruption of transportation of oil or natural gas produced from the wells in this area. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as the Williston Basin, which may cause these conditions to occur with greater frequency or magnify the effect of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations.

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Our business depends on oil and natural gas gathering and transportation facilities, most of which are owned by third parties.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of gathering and pipeline systems owned by third parties. The unavailability of, or lack of, available capacity on these systems and facilities could result in the shut-in of producing wells or the delay, or discontinuance of, development plans for properties. See also “Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production” and “Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.” We generally do not purchase firm transportation on third party pipeline facilities, and therefore, the transportation of our production can be interrupted by other customers that have firm arrangements. In addition, these third parties may also impose specifications for the products that they are willing to accept. If the total mix of a product fails to meet the applicable product quality specifications, the third parties may refuse to accept all or a part of the products or may invoice us for the costs to handle or damages from receiving the out-of-specification products. In those circumstances, we may be required to delay the delivery of or find alternative markets for that product, or shut-in the producing wells that are causing the products to be out of specification, potentially reducing our revenues.

The disruption of third-party facilities due to maintenance, weather or other interruptions of service could also negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored. A total shut-in of our production could materially affect us due to a resulting lack of cash flow, and if a substantial portion of the production is hedged at lower than market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flow. Potential crude oil rail derailments or crashes could also impact our ability to market and deliver our products and cause significant fluctuations in our realized oil and natural gas prices due to tighter safety regulations imposed on crude-by-rail transportation and interruptions in service.

Insufficient transportation or refining capacity in the Williston Basin could cause significant fluctuations in our realized oil and natural gas prices.

The Williston Basin crude oil business environment has historically been characterized by periods when oil production has surpassed local transportation and refining capacity, resulting in substantial discounts in the price received for crude oil versus prices quoted for WTI crude oil. In the past, there have been periods when this discount has substantially increased due to the production of oil in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. Recent expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the first quarter of 2015, as WTI declined, our price differentials increased as a percentage of WTI to a 16% discount but decreased in terms of the dollar per barrel discount to WTI to an average of $7.85 per barrel of oil. In the second quarter of 2015, as WTI improved, our price differentials decreased to approximately 10% as a percentage of WTI and continued to decrease in terms of the dollar per barrel discount to WTI to an average of $5.90 per barrel of oil. In the second half of 2015, while WTI fell again, our price differentials strengthened, decreasing to less than $5.00 per barrel of oil and remaining at approximately 10% as a percentage of WTI. On barrels that are transported over pipelines to either Clearbrook, Minnesota or Guernsey, Wyoming, our realized price for crude oil is generally the quoted price for Bakken crude oil less transportation costs from the point where the crude oil is sold.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. If our production becomes shut-in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

The development of our proved undeveloped reserves in the Williston Basin and other areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

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Approximately 32% of our estimated net proved reserves were classified as proved undeveloped as of December 31, 2015. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecasts as well as access to liquidity sources, such as capital markets, our revolving credit facility and derivative contracts. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the PV-10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as unproved reserves.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our estimated net proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gas or other pollutants into the environment;
- abnormally pressured formations;
- shortages of, or delays in, obtaining water for hydraulic fracturing activities;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing failure;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

Insurance against all operational risk is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. In addition, pollution and environmental risks generally are not fully insurable. Also, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

We have incurred losses in 2015 and prior years and may do so again in the future.

For the year ended December 31, 2015, we incurred a net loss of $40.2 million. For the years ended December 31, 2014 and 2013, we had net income of $506.9 million and $228.0 million, respectively. Our development of and participation in an

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increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures, including planned capital expenditures for 2016 of approximately $400 million.

The uncertainty and risks described in this Annual Report on Form 10-K may impede our ability to economically find, develop, exploit and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

Drilling locations that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from the well or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in the Williston Basin may not be indicative of future or long-term production rates. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our potential drilling location inventories are scheduled to be drilled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill a substantial portion of our potential drilling locations.

Our management has identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These potential drilling locations, including those without proved undeveloped reserves, represent a significant part of our execution strategy. Our ability to drill and develop these locations is subject to a number of uncertainties, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. Pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. These rules and guidance may limit our potential to book additional proved undeveloped reserves as we pursue our drilling program.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In the highly competitive market for acreage, failure to drill sufficient wells in order to hold acreage will result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2015, we had leases representing 16,556 net acres expiring in 2016, 8,935 net acres expiring in 2017 and 7,938 net acres expiring in 2018. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. In addition, on certain portions of our acreage, third-party leases become immediately effective if our leases expire. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business. During the years ended December 31, 2015, 2014 and 2013, we recorded non-cash impairment charges of $36.6 million, $7.3 million and $1.2 million on our unproved properties due to expiring leases and periodic assessments of our unproved properties.

Our operations are subject to environmental and occupational health and safety laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration and production operations are subject to stringent federal, regional, state and local laws and regulations governing occupational health and safety aspects of our operations, the discharge of materials into the environment or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations that are applicable to our operations including the acquisition of a permit before conducting drilling, underground injection or other regulated activities; the restriction on types, quantities and concentration of materials that may be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the EPA, and

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analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, which may cause us to incur significant capital or operating expenditures or costly actions to achieve and maintain compliance. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties; the imposition of investigatory, remedial or corrective action obligations; the occurrence of delays in the development of projects; and the issuance of injunctions limiting or preventing some or all of our operations in affected areas.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and waste water discharges related to our operations and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to joint and several, strict liability for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if the operations were in compliance with all applicable laws at the time those actions were taken. Private parties, including the owners of properties upon which our wells are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property damage. In addition, the risk of accidental spills or releases could expose us to significant liabilities that could have a material adverse effect on our financial condition or results of well drilling, construction, completion on water management activities or operations. Changes in environmental laws and regulations occur frequently, and any changes that result in delays or restrictions in the permitting or development of projects or more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. For example, the NDIC adopted regulations in late 2013 that impose more rigorous pipeline development standards on midstream operators, some of whom we rely upon to construct and operate pipeline infrastructure to transport the oil and natural gas we produce. In addition, in 2014, the NDIC adopted legal requirements and implemented a drilling permit review process that incorporates public review measures for any oil and natural gas wells drilled within buffer zones established around a designated number of identified areas of interest within the state, including certain National Park or Grassland areas, specified mountains and buttes, certain rivers, and specified wildlife management areas. While limited to drilling of wells upon public lands, the drilling permit review process will result in portions of the drilling applications being made available for public review and comment and could result in a lesser number of such permits being issued or such permits being issued at a slower rate or with added restrictions, which could impact our overall drilling program.

With regard to recent federal laws or regulations, in May 2015, the EPA released a final rule that attempted to clarify federal jurisdiction under the Clean Water Act with regards to obtaining permits for dredge and fill activities in wetland areas, the implementation of which has been stayed nationwide due to a number legal challenges, and, in October 2015, the EPA issued a final rule lowering the NAAQS for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. Compliance with any of these rules or any other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

We may not be able to recover some or any of these costs from insurance.

Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties.

Our operations are substantially affected by federal, state and local laws and regulations, particularly as they relate to the regulation of oil and natural gas production and transportation. These laws and regulations include regulation of oil and natural gas exploration and production and related operations, including a variety of activities related to the drilling of wells, the interstate transportation of oil and natural gas by federal agencies such as the FERC, as well as state agencies. In addition, federal laws prohibit market manipulation in connection with the purchase or sale of oil and/or natural gas. Failure to comply with federal, state and local laws could adversely affect our ability to produce, gather and transport our oil and natural gas and may result in substantial penalties. Please see "Item 1. Business—Other

federal laws and regulations affecting our industry.”
Our business involves the selling and shipping by rail of crude oil, including from the Bakken shale, which involves risks of derailment, accidents and liabilities associated with cleanup and damages, as well as potential regulatory changes that may adversely impact our business, financial condition or results of operations.
A portion of our crude oil production is transported to market centers by rail. Recent derailments in North America of trains transporting crude oil have caused various regulatory agencies and industry organizations, as well as federal, state and municipal governments, to focus attention on transportation by rail of flammable materials. Transportation safety regulators in the United States and Canada are concerned that crude oil from the Bakken shale may be more flammable than crude oil from other producing regions and are investigating that issue and are also considering changes to existing regulations to address

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those possible risks. In May 2015, PHMSA adopted a final rule that, among other things, imposes a new and enhanced tank car design standard for certain tank cars carrying crude oil and ethanol, a phase out by as early as January 2018 for older DOT-111 tank cars that are not retrofitted, and a classification and testing program for unrefined petroleum based products, including crude oil. The rule also includes new operational requirements such as routing analyses, speed restrictions and enhanced braking controls. Transport Canada has also issued legal requirements that align with the U.S. May 2015 final rule adopted by PHMSA, including standards relating to train speed restrictions, route risk analyses and a phase out of non-compliant DOT-111 tank cars.

Any changes to existing laws and regulations, or promulgation of new laws and regulations, including any voluntary measures by the rail industry, that result in new requirements for the design, construction or operation of tank cars used to transport crude oil could increase our costs of doing business and limit our ability to transport and sell our crude oil at favorable prices at market centers throughout the United States, the consequences of which could have a material adverse effect on our financial condition, results of operations and cash flows.

To the extent that new regulations require design changes or other modifications of tank cars, we may incur significant constraints on transportation capacity during the period while tank cars are being retrofitted or newly constructed to comply with the new regulations. In addition, any derailment of crude oil from the Bakken shale involving crude oil that we have sold or are shipping may result in claims being brought against us that may involve significant liabilities. Although we believe that we are adequately insured against such events, we cannot assure you that our insurance policies will cover the entirety of any damages that may arise from such an event.

Climate change legislation and regulatory initiatives restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

Based on findings by the EPA that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the Earth’s atmosphere and other climatic changes, the EPA adopted regulations under existing provisions of the CAA that establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically will be established by the states. These or similar permit review requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources in the United States on an annual basis, including, among others, certain onshore oil and natural gas production facilities, which includes certain of our operations. While from time to time Congress has considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. The adoption and implementation of any legislation or regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production activities, as part of an overall effort to reduce methane emissions by up to 45% in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how new methane restrictions would impact our business or how or when the United State might impose restrictions on GHGs as a result of the international agreement agreed to in Paris. The adoption of any legislation or regulations that require reporting of GHGs or otherwise restrict emissions of GHGs from the drilling program's equipment and operations could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, acquire emissions allowances or comply with new regulatory or reporting requirements including the imposition of a carbon tax. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA issued CAA final regulations in 2012 and proposed additional CAA regulations in August 2015 governing performance standards for the oil and natural gas industry; proposed in April 2015 effluent limitations guidelines that waste water from shale natural gas extraction operations must meet before discharging to a treatment plant; and issued in 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups. In addition, from time to time Congress has considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, following the lead of the State of New York in 2015. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA released its draft report on the potential impacts of hydraulic fracturing on drinking water resources in June 2015, which report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA’s Science Advisory Board provided its comments on the draft study, indicating its concern that EPA’s conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional drilling locations and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing equipment and trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory drilling locations or to identify, evaluate, bid for and purchase a greater number of properties and locations than our financial or personnel resources permit. Furthermore, these companies may also be better able to withstand the financial pressures of unsuccessful drilling attempts, sustained periods of volatility in financial markets and generally adverse global and industry-wide economic conditions, and may be better able to absorb the burdens resulting from changes in relevant laws and regulations, which would adversely affect our competitive position. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect our operations.

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To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Thomas B. Nusz, our Chairman and Chief Executive Officer, and Taylor L. Reid, our President and Chief Operating Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Seasonal weather conditions adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Williston Basin are adversely affected by seasonal weather conditions. In the Williston Basin, drilling and other oil and natural gas activities cannot be conducted as effectively during the winter months. Severe winter weather conditions limit and may temporarily halt our ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our operations and materially increase our operating and capital costs.

The inability of one or more of our customers to meet their obligations to us may adversely affect our financial results.

Our principal exposures to credit risk are through receivables resulting from the sale of our oil and natural gas production ($96.5 million in receivables at December 31, 2015), which we market to energy marketing companies, refineries and affiliates; joint interest receivables ($64.3 million at December 31, 2015); and deposits to vendors ($9.7 million at December 31, 2015).

We are subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. This concentration of customers may impact our overall credit risk since these entities may be similarly affected by changes in economic and other conditions. For the year ended December 31, 2015, sales to Shell Trading (US) Company accounted for approximately 10% of our total sales. For the years ended December 31, 2014 and 2013, sales to Musket Corporation accounted for approximately 13% and 11% of our total sales, respectively. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2015, 2014 and 2013. We do not require all of our customers to post collateral. 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.

Joint interest receivables arise from billing entities who own a 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.

In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. Derivative assets and liabilities arising from derivative contracts with the same counterparty are reported on a net basis, as all counterparty contracts provide for net settlement. At December 31, 2015, we had derivatives in place with eight counterparties and a total net derivative asset of $155.5 million.

We may be subject to risks in connection with acquisitions because of uncertainties in evaluating recoverable reserves, well performance and potential liabilities, as well as uncertainties in forecasting oil and gas prices and future development, production and marketing costs, and the integration of significant acquisitions may be difficult.

We periodically evaluate acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the seller's title to the properties, which may be less than expected at the time of signing the purchase agreement; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual

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indemnification for environmental liabilities or title defects in excess of the amounts claimed by us before closing and acquire properties on an "as is" basis. Indemnification from the sellers will generally be effective only during a limited time period after the closing and subject to certain dollar limitations and minimums. We may not be able to collect on such indemnification because of disputes with the sellers or their inability to pay. Moreover, there is a risk that we could ultimately be liable for unknown obligations related to acquisitions, which could materially adversely affect our financial condition, results of operations or cash flows.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating assets could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer. In addition, even if we successfully integrate the assets acquired in an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame.

If we fail to realize the anticipated benefits of a significant acquisition, our results of operations may be lower than we expect.

The success of a significant acquisition will depend, in part, on our ability to realize anticipated opportunities from combining the acquired assets or operations with those of ours. Even if a combination is successful, it may not be possible to realize the full benefits we may expect in estimated net proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices, in oil and natural gas industry conditions, by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest.

Prior to the drilling of an oil or gas well, however, it is the normal practice in our industry for the person or company acting as the operator of the well to obtain a preliminary title review to ensure there are no obvious defects in the title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct defects in the marketability of the title, and such curative work entails expense. Our failure to cure any title defects may adversely impact our ability in the future to increase production and reserves. There is no assurance that we will not suffer a monetary loss from title defects or title failure. Additionally, undeveloped acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the negative effect of commodity price changes, interest rate and other risks associated with our business.

On July 21, 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC, the

SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the U.S. District Court for the District of Columbia in September of 2012, although the CFTC has stated that it will appeal the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap," "security-based swap," "swap dealer" and "major swap participant." The Dodd-Frank Act and CFTC Rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to separate entities which may not be as creditworthy as the current counterparties. The Dodd-Frank Act and regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act is to lower commodity prices. Any of these consequences could have a material adverse effect on our financial position, results of operations and cash flows.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of proposed legislation.

President Obama's budget proposal for fiscal year 2017 recommended the elimination of certain key United States federal income tax preferences currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for United States production activities for oil and gas production, and (iv) the extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether any such changes or similar changes will be enacted or, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production. Any such changes could have an adverse effect on our financial position, results of operations and cash flows.

Risks Relating to our Common Stock

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, our shareholders' only opportunity to achieve a return on their investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our revolving credit facility and the indentures governing our senior unsecured notes. Consequently, our shareholders' only opportunity to achieve a return on their investment in us will be if the market price of our common stock appreciates, which may not occur, and the shareholder sells their shares at a profit. There is no guarantee that the price of our common stock will ever exceed the price that the shareholder paid.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation authorizes our Board of Directors to issue preferred stock without stockholder approval. If our Board of Directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- a classified Board of Directors, so that only approximately one-third of our directors are elected each year;

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- limitations on the removal of directors; and
- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the Board of Directors to be acted upon at meetings of stockholders.

Delaware law prohibits us from engaging in any business combination with any "interested stockholder," meaning generally that a stockholder who beneficially owns more than 15% of our stock cannot acquire us for a period of three years from the date this person became an interested stockholder, unless various conditions are met, such as approval of the transaction by our Board of Directors.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

Although we may, from time to time, be involved in litigation and claims arising out of our operations in the normal course of business, we are not currently a party to any material legal proceeding other than those noted below. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

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

We believe that all claims against Oasis Petroleum Inc. and OP LLC in connection with the derailment of the Train in Lac-Mégantic, Quebec are without merit.

On August 7, 2013, MMA filed for bankruptcy protection in the Quebec Superior Court and the United States Bankruptcy Court in Bangor, Maine (together, the "Bankruptcy Actions"). The trustees appointed in the Bankruptcy Actions have negotiated settlement agreements with the majority of the named defendants in the Class-Action, including Oasis Petroleum Inc. and OP LLC. The Quebec Superior Court and the United States Bankruptcy Court have issued orders approving the settlement agreements which were pending before them, and such orders have become final. Pursuant to the settlement agreements, Oasis Petroleum Inc. and OP LLC agreed to contribute to the compensation fund established for those suffering losses as a result of the Lac-Megantic derailment. Such contributions were fully covered by our insurance policies. Furthermore, the settlement agreements bar future litigation against Oasis Petroleum Inc. and OP LLC in Canada and the United States arising out of the Lac-Megantic derailment.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market for Registrant's Common Equity. Our common stock is listed on the NYSE under the symbol "OAS."

The following table sets forth the range of high and low sales prices of our common stock for the two most recent fiscal years as reported by the NYSE:

	2015		2014	
	High	Low	High	Low
1st Quarter	$19.63	$12.05	$47.28	$38.68
2nd Quarter	$18.86	$14.23	$56.38	$41.01
3rd Quarter	$15.85	$8.04	$58.09	$40.85
4th Quarter	$14.15	$6.34	$41.90	$10.64

Holders. As of February 18, 2016, the number of record holders of our common stock was 567. Based on inquiry, management believes that the number of beneficial owners of our common stock is approximately 42,300.

Dividends. We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility and the indentures governing our senior unsecured notes restrict the payment of cash dividends on our common stock. We currently intend to retain all future earnings for the development of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future.

On February 24, 2016, the last sale price of our common stock, as reported on the NYSE, was $4.53 per share.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2015.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2015:

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
October 1 – October 31, 2015	2,283	$9.19	—	—
November 1 – November 30, 2015	1,545	11.97	—	—
December 1 – December 31, 2015	12,197	11.33	—	—
Total	16,025	$11.09	—	—

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

Stock Performance Graph. The following performance graph and related information is "furnished" with the SEC and shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act or the Exchange Act, except to the extent that we specifically request that such information be treated as "soliciting material" or specifically incorporate such information by reference into such a filing.

The performance graph shown below compares the cumulative total return to our common stockholders as compared to the cumulative total returns on the Standard and Poor's 500 Index ("S&P 500") and the Standard and Poor's 500 Oil &

Gas Exploration & Production Index (“S&P 500 O&G E&P”) since the time of our initial public offering. The comparison was prepared based upon the following assumptions:

1. $100 was invested in our common stock at its initial public offering price of $14 per share and invested in the S&P 500 and the S&P 500 O&G E&P on June 16, 2010 at the closing price on such date; and

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2. Dividends were reinvested.

Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2011 through 2015. This information may not be indicative of our future results of operations, financial position and cash flows and should be read in conjunction with the consolidated financial statements and notes thereto and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” presented elsewhere in this Annual Report on Form 10-K. We believe that the assumptions underlying the preparation of our historical consolidated financial statements are reasonable.

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	Year ended December 31,				
	2015	2014	2013(1)	2012	2011
	(In thousands, except per share data)				
Statement of operations data:					
Revenues:					
Oil and gas revenues	$721,672	$1,304,004	$1,084,412	$670,491	$330,422
Well services and midstream revenues	68,063	86,224	57,587	16,177	—
Total revenues	789,735	1,390,228	1,141,999	686,668	330,422
Expenses:					
Lease operating expenses(2)	144,481	169,600	94,634	54,924	32,707
Well services and midstream operating expenses	28,031	50,252	30,713	11,774	—
Marketing, transportation and gathering expenses	31,610	29,133	25,924	9,257	1,365
Production taxes	69,584	127,648	100,537	62,965	33,865
Depreciation, depletion and amortization	485,322	412,334	307,055	206,734	74,981
Exploration expenses	2,369	3,064	2,260	3,250	1,685
Rig termination(3)	3,895	—	—	—	—
Impairment of oil and gas properties(4)	46,109	47,238	1,168	3,581	3,610
General and administrative expenses	92,498	92,306	75,310	57,190	29,435
Total expenses	903,899	931,575	637,601	409,675	177,648
Gain on sale of properties	—	186,999	—	—	(207)
Operating income (loss)	(114,164)	645,652	504,398	276,993	152,567
Other income (expense):					
Net gain (loss) on derivative instruments	210,376	327,011	(35,432)	34,164	1,595
Interest expense, net of capitalized interest	(149,648)	(158,390)	(107,165)	(70,143)	(29,618)
Other income (expense)	(2,935)	195	1,216	4,860	1,635
Total other income (expense)	57,793	168,816	(141,381)	(31,119)	(26,388)
Income before income taxes	(56,371)	814,468	363,017	245,874	126,179
Income tax benefit (expense)	16,123	(307,591)	(135,058)	(92,486)	(46,789)
Net income (loss)	$(40,248)	$506,877	$227,959	$153,388	$79,390
Earnings (loss) per share:					
Basic	$(0.31)	$5.09	$2.45	$1.66	$0.86
Diluted	(0.31)	5.05	2.44	1.66	0.86

(1) Our statement of operations data for the year ended December 31, 2013 does not include the effects of our 2013 acquisitions for the full twelve months of 2013. We acquired such interests on September 26, 2013 and October 1, 2013. See Note 6 to our audited consolidated financial statements.

(2) For the year ended December 31, 2011, lease operating expenses exclude marketing, transportation and gathering expenses to conform such amounts to current year classifications. For the years ended December 31, 2012 and 2011, lease operating expenses include midstream income and operating expenses, which are included in well services and midstream revenues and well services and midstream operating expenses, respectively, for the years ended December 31, 2015, 2014 and 2013.

(3) During the year ended December 31, 2015, we elected to early terminate certain drilling rig contracts and recorded a rig termination expense of $3.9 million.

(4) For the years ended December 31, 2015 and 2014, impairment of oil and gas properties includes $9.4 million and $40.0 million, respectively, related to our proved properties. See Note 3 to our audited consolidated financial statements.

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	At December 31,				
	2015	2014	2013	2012	2011
	(In thousands)				
Balance sheet data:					
Cash and cash equivalents	$9,730	$45,811	$91,901	$213,447	$470,872
Net property, plant and equipment	5,218,242	5,186,786	4,079,750	2,006,600	1,079,955
Total assets[(1)]	5,649,375	5,909,076	4,678,041	2,508,146	1,711,740
Long-term debt[(1)]	2,302,584	2,670,664	2,501,687	1,179,352	784,358
Total stockholders' equity	2,319,342	1,872,301	1,348,549	795,005	634,238

(1) Prior to 2015, we presented deferred financing costs related to our senior unsecured notes in other assets on our Consolidated Balance Sheet. Upon the adoption of new accounting guidance in 2015, such costs are presented as a deduction from the carrying value of long-term debt. As of December 31, 2015, deferred financing costs related to our senior unsecured notes totaling $35.4 million were included in long-term debt on our Consolidated Balance Sheet. Prior periods have been adjusted retrospectively to reflect the period-specific effects of applying the new guidance. Reclassified amounts total $29.3 million, $33.9 million, $20.6 million and $15.6 million for the years ended December 31, 2014, 2013, 2012 and 2011, respectively.

	Year ended December 31,				
	2015	2014	2013	2012	2011
	(In thousands)				
Other financial data:					
Net cash provided by operating activities	$359,815	$872,516	$697,856	$392,386	$176,024
Net cash used in investing activities	(479,148)	(1,077,452)	(2,445,076)	(1,038,605)	(629,390)
Net cash provided by financing activities	83,252	158,846	1,625,674	388,794	780,718

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Item 7. 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 our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains "forward-looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results, and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil and natural gas prices, the timing of planned capital expenditures, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Cautionary note regarding forward-looking statements."

Overview

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

Our use of capital for acquisitions and development allows us to direct our capital resources to what we believe to be the most attractive opportunities as market conditions evolve. We have historically acquired properties that we believe will meet or exceed our rate of return criteria. We built our Williston Basin assets through acquisitions and development activities, which were financed with a combination of capital from private investors, borrowings under our revolving credit facility, cash flows provided by operating activities, proceeds from our senior unsecured notes, proceeds from our public equity offerings, the sale of non-core oil and gas properties and cash settlements of derivative contracts. For acquisitions of properties with additional development, exploitation and exploration potential, we have focused on acquiring properties that we expect to operate so that we can control the timing and implementation of capital spending. In some instances, we have acquired non-operated property interests at what we believe to be attractive rates of return either because they provided an entry into a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated properties to the extent we believe they meet our return objectives. In addition, the acquisition of non-operated properties in new areas provides us with geophysical and geologic data that may lead to further acquisitions in the same area, whether on an operated or non-operated basis.

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

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

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Crude oil prices have declined significantly since mid-2014. As a result of sustained low oil prices, we have decreased our planned 2016 capital expenditures as compared to 2015, and we are continuing to concentrate our drilling activities in certain areas that are the most economic in the Williston Basin. Extended periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

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. The current global oversupply of crude oil has caused a sharp decline in oil prices since mid-2014. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk and enter into physical delivery contracts to manage our price differentials. In an effort to improve price realizations

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from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, we sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of December 31, 2015, we were flowing over 80% of our gross operated oil production through these gathering systems. Please see "Item 1. Business—Marketing, transportation and major customers."

Our quarterly average net realized oil prices and average price differentials are shown in the tables below.

	2015				Year ended
	Q1	Q2	Q3	Q4	December 31, 2015
Average Realized Oil Prices ($/Bbl)(1)	$40.73	$52.04	$41.61	$37.77	$43.04
Average Price Differential(2)	16 %	10 %	10 %	10 %	12 %

	2014				Year ended
	Q1	Q2	Q3	Q4	December 31, 2014
Average Realized Oil Prices ($/Bbl)(1)	$89.66	$94.48	$87.17	$62.79	$82.73
Average Price Differential(2)	9 %	8 %	10 %	13 %	10 %

	2013				Year ended
	Q1	Q2	Q3	Q4	December 31, 2013
Average Realized Oil Prices ($/Bbl)(1)	$93.33	$91.15	$100.75	$85.87	$92.34
Average Price Differential(2)	1 %	3 %	5 %	12 %	6 %

(1) Realized oil prices do not include the effect of derivative contract settlements.
(2) Price differential reflects the difference between realized oil prices and WTI crude oil index prices.

Changes in commodity prices may also significantly affect the economic viability of drilling projects as well as the economic valuation and economic recovery of oil and gas reserves. Crude oil produced and sold in the Williston Basin has historically sold at a discount to WTI due to transportation costs and takeaway capacity. In the past, there have been periods when this discount has substantially increased due to oil production in the area increasing to a point that it temporarily surpasses the available pipeline transportation, rail transportation and refining capacity in the area. Recent expansions of both rail and pipeline facilities have reduced the prior constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. In early 2013, our average price differentials relative to WTI narrowed, primarily due to our ability to access premium coastal markets by rail. As the premium received in coastal markets contracted during the second and third quarters of 2013, our average price differentials relative to WTI increased. In the fourth quarter of 2013 and into the first quarter of 2014, our average price differentials relative to WTI continued to increase due to the pipeline market weakening as a result of refinery down time and increased U.S. and Canadian production. In the second and third quarters of 2014, stronger pipeline prices shifted more of our barrels towards the pipelines, but rail buyers had to compete with pipeline prices despite weaker Brent differentials, resulting in price differentials relative to WTI of approximately 9% to 11%. In the fourth quarter of 2014, as WTI crude oil prices declined, our price differentials increased as a percentage of WTI but remained relatively flat in terms of the dollar per barrel discount to WTI in the range of $9.00 to $10.50 per barrel of oil. In 2015, our price differentials relative to WTI strengthened as new pipelines opened to eastern Canada and U.S. markets and transportation on rail gradually declined. In the first quarter of 2015, as WTI further declined, our price differentials continued to increase as a percentage of WTI but decreased in terms of the dollar per barrel discount to WTI to an average of $7.85 per barrel of oil. In the second quarter of 2015, as WTI improved, our price differentials returned to approximately 10% as a percentage of WTI and continued to decrease in terms of the dollar per barrel discount to WTI to an average of $5.90 per barrel of oil. In the second half of 2015, while WTI fell again, our price differentials strengthened, decreasing to less than $5.00 per barrel of oil and remaining at approximately 10% as a percentage of WTI. Our market optionality on the crude oil gathering systems allows us to shift volumes between pipeline and rail markets in order to optimize price realizations.

We believe our large concentrated acreage position provides us with a multi-year inventory of drilling projects and requires forward planning visibility for obtaining services and necessary permits to drill wells. As a result of lower future oil price expectations, we are continuing to slow the pace of development in 2016, and plan to reduce our well completions from 80 gross (62.4 net) operated wells in 2015 to 46 gross (28.6 net) operated wells in 2016. Additionally, we started completing 100% of our wells with OWS in February 2015 and have the ability to control the pace of completions to allow for additional financial flexibility. In 2015, we wrote off $22.2 million of leases that we do not expect to develop before their 2016 and 2017 contract expirations, as we continue to focus our 2016 drilling activities in the deepest part of our acreage in the Williston Basin.

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Our 2015, 2014 and 2013 activities included development and exploration drilling in the Williston Basin. Our current activities are focused on evaluating and developing our asset base and optimizing our operations. Based on the reserve reports prepared by our independent reserve engineers, we had 218.2 MMBoe of estimated net proved reserves with a PV-10 of $2,022.7 million and a Standardized Measure of $1,914.3 million at December 31, 2015, 272.1 MMBoe of estimated net proved reserves with a PV-10 of $5,481.4 million and a Standardized Measure of $3,981.7 million at December 31, 2014 and 227.9 MMBoe of estimated net proved reserves with a PV-10 of $5,486.9 million and a Standardized Measure of $3,727.6 million at December 31, 2013. Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic average first-day-of-the-month prices for the prior twelve months for the years ended December 31, 2015, 2014 and 2013 were $50.16/Bbl for oil and $2.63/MMBtu for natural gas, $95.28/Bbl for oil and $4.35/MMBtu for natural gas and $96.96/Bbl for oil and $3.66/MMBtu for natural gas, respectively. These prices were adjusted by lease for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. Future operating costs, production taxes and capital costs were based on current costs as of each year-end. As of February 8, 2016, the spot crude oil price was $29.71 per barrel, a 20% decrease since December 31, 2015 and a 39% decrease as compared to an average WTI of $48.75 per barrel during the year ended December 31, 2015. An extended period of low oil prices could result in a significant decrease in our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure in the future.

Forward commodity prices and estimates of future production also play a significant role in determining impairment of proved oil and natural gas properties. As a result of lower commodity prices and their impact on our estimated future cash flows, we have continued to review our proved oil and natural gas properties for impairment. In 2014, we recorded a proved impairment loss of $40.0 million due to lower expected future oil prices, and in 2015, we recorded an impairment loss of $9.4 million to write down our proved properties held for sale to their estimated fair value. No other proved impairment charges were recorded during the year ended December 31, 2015, although the difference between the expected undiscounted future cash flows and the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations has narrowed to $1,264.8 million as of December 31, 2015, a decrease of approximately 56% as compared to December 31, 2014. The underlying commodity prices embedded in our estimated cash flows were determined using NYMEX forward swap prices for five years, escalating 3% per year thereafter effective as of December 31, 2015 and holding the fifth year price constant thereafter as of December 31, 2014. Effective as of December 31, 2015, a 3% inflation factor was also applied to the future operating and development costs after five years. Expected future oil and natural gas prices have continued to decline in early 2016. As of February 12, 2016, the average five-year WTI strip price was $43.70 per barrel, a 10% decrease as compared to the average five-year WTI strip price as of December 31, 2015, which reduces the excess of the expected undiscounted cash flows over the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations to $327.2 million. If expected future oil prices decline by 13% as compared to December 31, 2015, holding all other factors constant, the expected undiscounted cash flows may not exceed the carrying value of our proved oil and natural gas properties in the Bakken and Three Forks formations, and as a result, we may recognize additional proved impairment charges in the future, and such impairment charges could exceed $2,500.0 million assuming a discount rate of 10%.

2015 Highlights

- We increased average daily production by 11% to 50,477 Boe per day in 2015 from 45,656 Boe per day in 2014.
- We completed and placed on production 80 gross (62.4 net) operated wells during 2015. As of December 31, 2015, the Company had 85 gross operated wells awaiting completion.
- Capital expenditures were $610.0 million for the year ended December 31, 2015, a 61% decrease as compared to 2014 capital expenditures.
- We had estimated net proved oil and natural gas reserves at December 31, 2015 of 218.2 MMBoe, of which 85% consisted of oil and 68% were classified as proved developed.
- We ended the year with a leasehold position of 484,745 total net acres in the Williston Basin, primarily targeting the Bakken and Three Forks formations. In addition, we increased our acreage that is held by production to 442,292 net

acres as of December 31, 2015.

- At December 31, 2015, we had $9.7 million of cash and cash equivalents and had total pro forma liquidity of $1,199.4 million, including adjustments for the current borrowing base and the net proceeds from our public equity offering in February 2016 (see “Liquidity and capital resources” below).

Results of Operations

Revenues

Our oil and gas revenues are derived from the sale of oil and natural gas production. These revenues do not include the effects of derivative instruments and may vary significantly from period to period as a result of changes in volumes of production sold

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or changes in commodity prices. Our well services and midstream revenues are primarily derived from well completion activity, tool rentals, salt water pipeline transport, salt water disposal and fresh water sales for third-party working interest owners in OPNA's operated wells. Intercompany revenues for work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation.

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

	Year ended December 31,		
	2015	2014	2013
Operating results (in thousands):			
Revenues			
Oil	$692,497	$1,231,251	$1,033,866
Natural gas	29,175	72,753	50,546
Well services	44,294	74,610	51,845
Midstream	23,769	11,614	5,742
Total revenues	$789,735	$1,390,228	$1,141,999
Production data:			
Oil (MBbls)	16,091	14,883	11,133
Natural gas (MMcf)	14,002	10,691	7,450
Oil equivalents (MBoe)	18,424	16,664	12,375
Average daily production (Boe per day)	50,477	45,656	33,904
Average sales prices:			
Oil, without derivative settlements (per Bbl)(1)	$43.04	$82.73	$92.34
Oil, with derivative settlements (per Bbl)(1)(2)	66.06	83.19	91.61
Natural gas (per Mcf)(3)	2.08	6.81	6.78

(1) For the year ended December 31, 2013, average sales prices for oil is calculated using total oil revenues, excluding bulk oil sales of $5.8 million, divided by oil production.

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

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

Year ended December 31, 2015 as compared to year ended December 31, 2014

Total revenues. Our total revenues decreased $600.5 million, or 43%, to $789.7 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014, primarily due to lower realized oil and natural gas sales prices, partially offset by increased production volumes sold. Our average realized prices for oil and natural gas decreased by 48% and 69%, respectively, during the year ended December 31, 2015 as compared to December 31, 2014. Net production volumes for the year ended December 31, 2015 were 18,424 MBoe, an 11% increase from net production of 16,664 MBoe for the year ended December 31, 2014. Our net production volumes increased 1,760 MBoe over 2014 primarily due to a successful operated and non-operated drilling and completion program.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 4,821 Boe per day, or 11%, to 50,477 Boe per day during the year ended December 31, 2015 as compared to the year ended December 31, 2014. The increase in average daily production sold was primarily a result of our 64.3 total net well completions in the Williston Basin during 2015, offset by the natural decline in production in wells that were producing as of December 31, 2014. Production from wells completed contributed to average daily production during 2015 by approximately 11,366 Boe per day. Average oil sales prices, without derivative settlements, decreased by $39.69 per barrel, or 48%, to an average of $43.04 per barrel, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, decreased by $4.73 per Mcf to an average of $2.08 per Mcf for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The lower oil and natural gas sales prices decreased revenues by

$641.2 million, partially offset by higher production amounts sold, which increased revenues by $58.9 million during the year ended December 31, 2015. As of February 8, 2016, the spot crude oil price was $29.71 per barrel, a 20% decrease since December 31, 2015 and a 39% decrease as compared to an average WTI of $48.75 per

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barrel during the year ended December 31, 2015. Extended current low commodity prices could result in a significant decrease in our oil and gas volumes and revenues in the future.

Well services and midstream revenues. Well services revenues decreased $30.3 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014 primarily due to a $26.8 million decrease in well completion product sales to third parties as a result of OWS completing substantially all of OPNA's operated wells in 2015, coupled with a decrease of $3.1 million in tool rentals as a result of running fewer rigs in 2015 as compared to 2014. Well completion activity increased year over year, but OWS completed OPNA wells with a lower average third-party working interest in 2015 as compared to 2014, resulting in a net decrease of $0.3 million in well completion revenue. While a lower average third-party working interest decreases the well completion revenue recognized in our consolidated results of operations, it improves our capital expenditures by reducing OPNA well costs. Midstream revenues totaled $23.8 million for the year ended December 31, 2015, a $12.2 million increase year over year, primarily due to a $9.1 million increase in salt water disposal revenue due to increased water volumes flowing through our salt water disposal systems as a result of increased well connections and capacity additions in areas that previously had bottlenecks coupled with a $1.9 million increase in fresh water sales revenue.

Year ended December 31, 2014 as compared to year ended December 31, 2013

Total revenues. Our total revenues increased $248.2 million, or 22%, to $1,390.2 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013, primarily due to increased production volumes sold, partially offset by lower realized oil sales prices. Net production volumes for the year ended December 31, 2014 were 16,664 MBoe, a 35% increase from net production of 12,375 MBoe for the year ended December 31, 2013. Our net production volumes increased 4,289 MBoe over 2013 primarily due to a successful operated and non-operated drilling and completion program.

Oil and gas revenues. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 11,752 Boe per day, or 35%, to 45,656 Boe per day during the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in average daily production sold was primarily a result of our 151.1 total net well completions in the Williston Basin during 2014 and our acquisitions of oil and natural gas properties in the Williston Basin in the second half of 2013 (the "2013 Acquisitions"), offset by the natural decline in production in wells that were producing as of December 31, 2013 and the Sanish Divestiture. Production from wells completed contributed to average daily production during 2014 by approximately 13,805 Boe per day. The Sanish Divestiture in the first quarter of 2014 resulted in a decrease in average daily production of approximately 2,308 Boe per day during 2014. Average oil sales prices, without derivative settlements, decreased by $9.61 per barrel, or 10%, to an average of $82.73 per barrel, and average natural gas sales prices, which include the value for natural gas and natural gas liquids, increased slightly by $0.03 per Mcf to an average of $6.81 per Mcf for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The higher production amounts sold increased revenues by $332.2 million, partially offset by lower oil sales prices, which decreased revenues by $107.0 million during the year ended December 31, 2014. In addition, bulk oil sales related to marketing activities included in oil revenues decreased $5.8 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013.

Well services and midstream revenues. Well services revenues increased $22.8 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013 due to an increase in well completion activity as a result of adding a second OWS fracturing fleet in 2014, coupled with increased well completion product sales and tool rentals. Midstream revenues totaled $11.6 million for the year ended December 31, 2014, a $5.9 million increase year over year, primarily due to increased water volumes flowing through our salt water disposal systems and fresh water sales.

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Expenses and other income

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

	Year ended December 31,		
	2015	2014	2013
	(In thousands, except per Boe of production)		
Expenses:			
Lease operating expenses[1]	$144,481	$169,600	$94,634
Well services and midstream operating expenses	28,031	50,252	30,713
Marketing, transportation and gathering expenses	31,610	29,133	25,924
Production taxes	69,584	127,648	100,537
Depreciation, depletion and amortization	485,322	412,334	307,055
Exploration expenses	2,369	3,064	2,260
Rig termination	3,895	—	—
Impairment of oil and gas properties	46,109	47,238	1,168
General and administrative expenses	92,498	92,306	75,310
Total expenses	903,899	931,575	637,601
Gain on sale of properties	—	186,999	—
Operating income (loss)	(114,164)	645,652	504,398
Other income (expense):			
Net gain (loss) on derivative instruments	210,376	327,011	(35,432)
Interest expense, net of capitalized interest	(149,648)	(158,390)	(107,165)
Other income (expense)	(2,935)	195	1,216
Total other income (expense)	57,793	168,816	(141,381)
Income before income taxes	(56,371)	814,468	363,017
Income tax benefit (expense)	16,123	(307,591)	(135,058)
Net income (loss)	$(40,248)	$506,877	$227,959
Costs and expenses (per Boe of production):			
Lease operating expenses[1]	$7.84	$10.18	$7.65
Marketing, transportation and gathering expenses	1.72	1.75	2.09
Production taxes	3.78	7.66	8.12
Depreciation, depletion and amortization	26.34	24.74	24.81
General and administrative expenses	5.02	5.54	6.09

(1) For the year ended December 31, 2013, lease operating expenses include midstream income and operating expenses, which are included in well services and midstream revenues and well services and midstream operating expenses, respectively, for the years ended December 31, 2015 and 2014.

Year ended December 31, 2015 as compared to year ended December 31, 2014

Lease operating expenses. Lease operating expenses decreased $25.1 million to $144.5 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. This decrease was primarily due to lower workover costs and an increase in salt water disposal volumes being transported on OMS pipelines and injected in OMS salt water disposal wells, partially offset by higher costs associated with operating an increased number of producing wells. We completed and placed on production 64.3 total net wells in the Williston Basin during the year ended December 31, 2015 as compared to 151.1 total net wells completed and placed on production during the year ended December 31, 2014. Lease operating expenses decreased from $10.18 per Boe for the year ended December 31, 2014 to $7.84 per Boe for the year ended December 31, 2015 due to the lower costs and increase in oil and natural gas production.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners’ share of completion service costs, cost of goods sold and operating expenses incurred by OWS and

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OMS. The $22.2 million decrease for the year ended December 31, 2015 as compared to the year ended December 31, 2014 was attributable to a $23.8 million decrease in well completion costs as a result of lower well completion product sales to third parties due to OWS completing substantially all of OPNA's operated wells, coupled with OWS completing OPNA wells with a lower average third-party working interest in the year ended December 31, 2015 as compared to December 31, 2014. This decrease was partially offset by a $1.6 million increase related to midstream operating expenses and fresh water purchases.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $2.5 million year over year, or a $0.03 decrease per Boe, which was primarily attributable to a $1.4 million increase in gas gathering charges related to additional well connections on OMS infrastructure, a $1.4 million increase in oil transportation costs associated with having additional wells connected to third-party infrastructure and a $0.3 million increase in our pipeline imbalance. These increases were partially offset by a decrease year over year of $0.9 million in the write down of our linefill inventory to the lower of cost or market value at year-end. Excluding non-cash valuation adjustments, our marketing, transportation and gathering expenses on a per Boe basis would have remained constant at $1.62 and $1.61 for the years ended December 31, 2015 and 2014, respectively. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

Production taxes. Our production taxes for the years ended December 31, 2015 and 2014 were 9.6% and 9.8%, respectively, as a percentage of oil and natural gas sales. The production tax rate decreased slightly year over year primarily due to reduced extraction tax rates triggered by lower oil prices on certain North Dakota wells, partially offset by an increased weighting of wells in North Dakota, which has a higher average production tax rate as compared to Montana. For the years ended December 31, 2015 and 2014, the percentage of our total production located in North Dakota was approximately 88% and 86%, respectively. In 2015 and 2014, North Dakota had a crude oil tax structure based on a 5% production tax and a 6.5% oil extraction tax, resulting in a combined tax rate of 11.5% of crude oil revenues. In 2016, the North Dakota oil extraction tax will be reduced to 5%, resulting in a 10% combined tax rate, which will rise by 0.5% if crude oil prices average above $90 per barrel for three consecutive months.

Depreciation, depletion and amortization ("DD&A"). DD&A expense increased $73.0 million to $485.3 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The increase in DD&A expense for the year ended December 31, 2015 was primarily due to an increase in the average DD&A rate per Boe year over year coupled with production increases from our wells completed during 2015. The DD&A rate for the year ended December 31, 2015 was $26.34 per Boe as compared to $24.74 per Boe for the year ended December 31, 2014. The increase in the DD&A rate was primarily due to lower recoverable reserves related to lower oil and natural gas prices and increased exploratory and delineation drilling in the Three Forks formation.

Rig termination. As a result of our lowered 2015 capital expenditure program, we elected to early terminate certain drilling rig contracts and recorded a rig termination expense of $3.9 million for the year ended December 31, 2015. We did not elect to early terminate any drilling rig contracts during the year ended December 31, 2014 or 2013.

Impairment of oil and gas properties. Due to lower expected future oil prices, we reviewed our proved oil and natural gas properties for impairment as of December 31, 2015 and 2014. For the year ended December 31, 2015, we recorded an impairment loss of $9.4 million to adjust the carrying value of our proved oil and natural gas properties held for sale to their estimated fair value. For the year ended December 31, 2014, we determined that the carrying value exceeded expected undiscounted cash flows for certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations. As a result, we recorded an impairment loss of $40.0 million to adjust the carrying amount of these assets to fair value. During the years ended December 31, 2015 and 2014, we also recorded non-cash impairment charges of $36.6 million and $7.3 million, respectively, for unproved properties due to leases that expired during the period and periodic assessments of unproved properties. The 2015 and 2014 impairment charges included $22.2 million related to acreage expiring in 2016 and 2017 and $2.9 million related to acreage expiring in 2015 and 2016, respectively, as a result of periodic assessments because there were no plans to drill or extend the leases prior to their expiration. In determining the amount of non-cash impairment charges for such periods, we considered the application of the factors described under “Critical accounting policies and estimates—Impairment of proved properties” and “Critical accounting policies and estimates—Impairment of unproved properties.”

General and administrative (“G&A”) expenses. Our G&A expenses increased $0.2 million to $92.5 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. E&P G&A was $83.0 million and $80.4 million for the years ended December 31, 2015 and 2014, respectively. The $2.6 million increase in E&P G&A was primarily due to increased employee compensation expenses, partially offset by increased shared services allocations to our OWS and OMS segments. OMS G&A increased $1.3 million for the year ended December 31, 2015 as compared to December 31, 2014 primarily due to increased employee compensation due to organizational growth within this segment. OWS G&A decreased by $3.6 million primarily due to OWS completing OPNA wells with a lower average third-party working interest in the year ended December 31, 2015 as compared to 2014. Consolidated G&A expenses included non-cash amortization for stock-based compensation of $25.3 million and $21.3 million in 2015 and 2014, respectively. While our full-time employee headcount decreased to 535 as of December 31, 2015 from 558 as of December 31, 2014, our average employee headcount was higher during 2015 as compared to 2014.

Gain on sale of properties. No gain or loss on sale of properties was recorded in the year ended December 31, 2015. In the year ended December 31, 2014, we recognized a $187.0 million gain related to the Sanish Divestiture.

Derivatives. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $210.4 million net gain on derivative instruments, including net cash settlement receipts of $370.4 million, for the year ended December 31, 2015, and a $327.0 million net gain on derivative instruments, including net cash settlement receipts of $6.8 million, for the year ended December 31, 2014. 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 decreased $8.7 million to $149.6 million for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The decrease was primarily due to increased interest costs capitalized due to increased work in progress, including the natural gas processing plant we are constructing in Wild Basin and 85 wells waiting on completion as of December 31, 2015. Interest expense incurred on borrowings under our revolving credit facility remained relatively constant during 2015 as compared to 2014. For the year ended December 31, 2015, the weighted average debt outstanding under our revolving credit facility was $261.2 million and the weighted average interest rate incurred on the outstanding borrowings was 1.8%. For the year ended December 31, 2014, the weighted average debt outstanding under our revolving credit facility was $272.3 million and the weighted average interest rate incurred on the outstanding borrowings was 1.8%. We capitalized $18.6 million and $8.8 million of interest costs for the years ended December 31, 2015 and 2014, respectively, which will be amortized over the life of the related assets.

Income tax benefit (expense). Income tax benefit for the year ended December 31, 2015 was recorded at 28.6% of pre-tax loss, and income tax expense for the year ended December 31, 2014 was recorded at 37.8% of pre-tax net income. While our 2014 effective tax rate was consistent with the statutory tax rate applicable to the U.S. and the blended state rate for the states in which we conduct business, our effective tax rate for the year ended December 31, 2015 was lower due to permanent differences between the amounts expensed for book purposes versus the amounts deductible for income tax purposes related to stock-based compensation vesting during the year ended December 31, 2015 at stock prices lower than the grant date values, partially offset by a reduction in the North Dakota statutory tax rate in 2015.

Year ended December 31, 2014 as compared to year ended December 31, 2013

Lease operating expenses. Lease operating expenses increased $75.0 million to $169.6 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our 2014 well completions and the 2013 Acquisitions, as well as increased workover costs, which include certain costs to protect producing wells from wells that are being completed. We completed and placed on production 151.1 total net wells in the Williston Basin during the year ended December 31, 2014 as compared to 115.1 total net wells completed and placed on production during the year ended December 31, 2013. Lease operating expenses increased from $7.65 per Boe for the year ended December 31, 2013 to $10.18 per Boe for the year ended December 31, 2014.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs, cost of goods sold and operating expenses incurred by OWS and OMS. The $19.5 million increase for the year ended December 31, 2014 as compared to the year ended December 31, 2013 was attributable to a $16.3 million increase from OWS' well completion activity and well completion product sales and a $3.2 million increase related to midstream operating expenses.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses increased $3.2 million year over year, or a $0.34 decrease per Boe, which was primarily attributable to increased oil transportation costs associated with having additional wells connected to third-party infrastructure and a $0.9 million increase due to an increase in the lower of cost or market adjustment on our linefill inventory partially offset by a decrease in the pipeline imbalance accrual. In addition, there was a $5.8 million decrease in costs related to bulk oil purchases. Excluding non-cash valuation adjustments and bulk oil purchase costs, our marketing, transportation and gathering expenses on a per Boe basis would have been $1.61 and $1.52 for the years ended December 31, 2014 and 2013, respectively. The transporting of volumes through third-party oil gathering pipelines increases marketing, transportation and gathering expenses but improves oil price realizations by reducing transportation costs included in our oil price differential for sales at the wellhead.

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Production taxes. Our production taxes for the years ended December 31, 2014 and 2013 were 9.8% and 9.3%, respectively, as a percentage of oil and natural gas sales. The 2014 production tax rate was higher than the 2013 production tax rate primarily due to the increased weighting of wells in North Dakota, which has higher production tax rates as compared to Montana. For the years ended December 31, 2014 and 2013, the percentage of our total production located in North Dakota was approximately 86% and 82%, respectively, with an average production tax rate of approximately 11%.

Depreciation, depletion and amortization. DD&A expense increased $105.3 million to $412.3 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in DD&A expense for the year ended December 31, 2014 was primarily a result of our production increases from our wells completed during 2014 and the 2013 Acquisitions. The DD&A rate for the year ended December 31, 2014 was $24.74 per Boe as compared to $24.81 per Boe for the year ended December 31, 2013. In the first two months of 2014, we had production from the wells sold in the Sanish Divestiture, but these wells were not depreciated because the assets were classified as held for sale, which lowered DD&A by $0.18 per Boe for the year ended December 31, 2014. Excluding the impact of the Sanish Divestiture, the increase in the DD&A rate was primarily due to the 2013 Acquisitions coupled with an increase in the drilling program into the Three Forks formation, offset by continued reductions to well costs.

Impairment of oil and gas properties. Due to lower expected future oil prices, we reviewed our proved oil and natural gas properties for impairment as of December 31, 2014 and determined that the carrying value exceeded the expected undiscounted cash flows for certain legacy wells that have been producing from conventional reservoirs such as the Madison, Red River and other formations in the Williston Basin other than the Bakken or Three Forks formations. As a result, we recorded an impairment loss of $40.0 million to adjust the carrying amount of these assets to fair value. No impairment of proved oil and natural gas properties was recorded for the year ended December 31, 2013. During the years ended December 31, 2014 and 2013, we also recorded non-cash impairment charges of $7.3 million and $1.2 million, respectively, for unproved properties due to leases that expired during the period and periodic assessments of unproved properties. The 2014 impairment charge included $2.9 million related to acreage expiring in 2015 and 2016 as a result of a periodic assessment because there were no plans to drill or extend the leases prior to their expiration. In 2013, we did not record any impairment charges as a result of periodic assessments based on our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that would otherwise expire. In determining the amount of non-cash impairment charges for such periods, we considered the application of the factors described under “Critical accounting policies and estimates—Impairment of proved properties” and “Critical accounting policies and estimates—Impairment of unproved properties.”

General and administrative expenses. Our G&A expenses increased $17.0 million for the year ended December 31, 2014 from $75.3 million for the year ended December 31, 2013. E&P G&A was $80.4 million and $68.8 million for the years ended December 31, 2014 and 2013, respectively. The $11.6 million increase in E&P G&A was primarily due to the impact of our organizational growth on employee compensation, partially offset by increased shared services allocations to the OWS and OMS segments. OWS G&A increased by $4.7 million primarily as a result of adding a second OWS fracturing fleet in 2014, and OMS G&A increased by $0.7 million. Consolidated G&A expenses included non-cash amortization for stock-based compensation of $21.3 million and $12.0 million in 2014 and 2013, respectively. As of December 31, 2014, we had 558 full-time employees as compared to 405 full-time employees as of December 31, 2013.

Gain on sale of properties. We recognized a gain on sale of properties of $187.0 million related to the Sanish Divestiture in the year ended December 31, 2014. No gain or loss on sale of properties was recorded in the year ended December 31, 2013.

Derivatives. As a result of entering into derivative contracts and the effect of the forward strip oil price changes, we incurred a $327.0 million net gain on derivative instruments, including net cash settlement receipts of $6.8 million, for the year ended December 31, 2014, and a $35.4 million net loss on derivative instruments, including net cash settlement payments of $8.1 million, for the year ended December 31, 2013. 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 $51.2 million to $158.4 million for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase was primarily due to the interest related to our senior unsecured notes issued in September 2013 at an interest rate of 6.875% coupled with interest expense incurred on borrowings under our revolving credit facility during 2014. For the year ended December 31, 2014, the weighted average debt outstanding under our revolving credit facility was $272.3 million and the weighted average interest rate incurred on the outstanding borrowings was 1.8%. For the year ended December 31, 2013, the weighted average debt outstanding under our revolving credit facility was $143.0 million and the weighted average interest rate incurred on the outstanding borrowings was 2.0%. We capitalized $8.8 million and $4.6 million of interest costs for the years ended December 31, 2014 and 2013, respectively, which will be amortized over the life of the related assets.

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Income tax expense. Income tax expense for the years ended December 31, 2014 and 2013 was recorded at 37.8% and 37.2% of pre-tax net income, respectively, which closely approximates the statutory rate applicable to the U.S. and the blended state rate of the states in which we conduct business.

Liquidity and capital resources

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

Our cash flows for the years ended December 31, 2015, 2014 and 2013 are presented below:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Net cash provided by operating activities	$359,815	$872,516	$697,856
Net cash used in investing activities	(479,148)	(1,077,452)	(2,445,076)
Net cash provided by financing activities	83,252	158,846	1,625,674
Net change in cash	$(36,081)	$(46,090)	$(121,546)

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil prices on a portion of our production, thereby mitigating our exposure to oil price declines, but these transactions may also limit our cash flow in periods of rising oil prices. Prices for oil have declined significantly since mid-2014, which has substantially decreased our cash flows provided by operating activities. The decline in operating cash flows caused by lower oil prices is partially offset by cash flows from our derivative contracts. We currently have derivative contracts in place to cover approximately 70% of our estimated 2016 oil production at an average WTI of $51.70 per barrel. On February 2, 2016, we completed a public equity offering resulting in net proceeds of $182.9 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we will use for general corporate purposes and to fund a portion of our 2016 capital expenditures. Our existing revolving credit facility provides additional liquidity, with a current borrowing base and elected commitment amount of $1,150.0 million. The next redetermination of the borrowing base is scheduled for October 1, 2016. We believe we have adequate liquidity to fund planned 2016 capital expenditures and to meet our near-term future obligations. For additional information on the impact of changing prices on our financial position, see “Item 7A. Quantitative and Qualitative Disclosures about Market Risk.”

Cash flows provided by operating activities

Net cash provided by operating activities was $359.8 million, $872.5 million and $697.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. The decrease in cash flows provided by operating activities for the year ended December 31, 2015 as compared to 2014 was primarily the result of the 48% decrease in realized prices for oil and the 69% decrease in realized prices for natural gas coupled with decreases in well completion product sales to third parties, offset by our 11% increase in oil and natural gas production and increases in salt water pipeline transport, salt water disposal and fresh water sales. The increase in cash flows provided by operating activities for the year ended December 31, 2014 as compared to 2013 was primarily the result of our 35% increase in oil and natural gas production coupled with increases in well completion activity, well completion product sales, tool rentals, salt water pipeline transport, salt water disposal and fresh water sales, offset by lower realized oil sales prices year over year.

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 $5.3 million at December 31, 2015, however, we believe we have adequate liquidity to meet our working capital requirements. As of December 31, 2015, including pro forma adjustments for our current borrowing base and the net proceeds from our February 2016 public equity offering, we had $1,199.4 million of liquidity available. At December 31, 2014, we had a working capital deficit of $98.5 million.

Cash flows used in investing activities

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We had net cash flows used in investing activities of $479.1 million, $1,077.5 million and $2,445.1 million during the years ended December 31, 2015, 2014 and 2013, respectively, primarily as a result of our capital expenditures for drilling, development and acquisition costs and cash settlements of derivative contracts. The decrease in cash used in investing activities for the year ended December 31, 2015 as compared to the year ended December 31, 2014 was primarily due to a 61% decrease in our capital expenditures year over year as a result of lower commodity prices. Net cash used in investing activities during the year ended December 31, 2015 was primarily attributable to $819.8 million in capital expenditures, which were primarily for the development of our properties, including OMS pipelines, salt water disposal wells and natural gas processing plant construction, partially offset by $370.4 million for derivative settlements received as a result of lower crude oil prices. Net cash used in investing activities during the year ended December 31, 2014 was primarily attributable to $1,354.3 million in capital expenditures for the development of our properties, including OMS pipelines and salt water disposal wells and the addition of a second fracturing fleet for OWS, partially offset by $324.9 million in proceeds from the Sanish Divestiture. Net cash used in investing activities during the year ended December 31, 2013 was primarily attributable to $1,560.1 million for the 2013 Acquisitions coupled with capital expenditures of $893.5 million for the development of our properties.

Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. Our capital expenditures for the years ended December 31, 2015, 2014 and 2013 are summarized in the following table:

	Year ended December 31,		
	2015	2014	2013
	(In thousands)		
Capital expenditures			
E&P	$465,698	$1,436,922	$2,461,185
OMS	96,947	68,939	18,955
OWS	21,711	37,292	15,217
Other capital expenditures(1)	25,643	29,440	10,941
Total capital expenditures(2)	$609,999	$1,572,593	$2,506,298

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

(2) Capital expenditures (including acquisitions) reflected in the table above differ from the amounts for capital expenditures and acquisition of oil and gas properties shown in the statement of cash flows in our 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.

In 2015, we spent $610.0 million on capital expenditures, which represented a 61% decrease as compared to the $1,572.6 million spent during 2014. This decrease was due to reduced drilling and completion activity as a result of lower commodity prices in 2015 coupled with lower well costs as a result of both improved operational efficiency and lower service costs, partially offset by higher capital expenditures for OMS, primarily related to the natural gas processing plant we are constructing in the Wild Basin area of our core acreage in North Dakota.

During 2015, we participated in 121 gross wells (64.3 net) that were completed and placed on production, and, as operator, we completed and placed on production 80 gross (62.4 net) of these wells. In addition, as of December 31, 2015, we had 85 gross operated wells awaiting completion in the Bakken and Three Forks formations. Our land leasing and acquisition activity is focused in and around our existing core consolidated land positions.

We have decreased our planned 2016 capital expenditures as compared to 2015 as a result of current lower oil prices. We anticipate investing $400 million in 2016 as follows:

	(In thousands)
Drilling and completion	$200,000
OMS, including Wild Basin infrastructure	140,000

Other[1]	60,000
Total capital expenditures	$400,000

(1) Other capital expenditures include approximately $18 million for capitalized interest.

While we have budgeted $400 million for total capital expenditures in 2016, 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 the proceeds from our equity offering in February 2016, cash flows from operating activities, proceeds from cash settlements under our derivative contracts and availability under our revolving credit facility should be sufficient to fund our 2016 capital expenditure budget. However, because the operated wells funded by our 2016 drilling plan represent only a small percentage of our potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

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

Cash flows provided by financing activities

Net cash provided by financing activities was $83.3 million, $158.8 million and $1,625.7 million for the years ended December 31, 2015, 2014 and 2013, respectively. For the year ended December 31, 2015, cash sourced through financing activities was provided by net proceeds from the issuance of our common stock, partially offset by net repayments on our revolving credit facility. For the year ended December 31, 2014, cash sourced through financing activities was provided by borrowings under our revolving credit facility. For the year ended December 31, 2013, cash sourced through financing activities was primarily provided by the issuance of our senior unsecured notes, borrowings under our revolving credit facility and net proceeds from the issuance of our common stock.

Sale of common stock. On March 9, 2015, we completed a public offering of 36,800,000 shares of our common stock at an offering price of $12.80 per share. We used the net proceeds from the offering of $462.8 million, after deducting underwriting discounts and commissions and estimated offering expenses, to repay outstanding indebtedness under our revolving credit facility and for general corporate purposes.

On February 2, 2016, we completed a public offering of 39,100,000 shares of our common stock at a purchase price of $4.685 per share. Net proceeds from the offering were $182.9 million, after deducting underwriting discounts and commissions and estimated offering expenses, which we intend to use for general corporate purposes and to fund a portion of our 2016 capital expenditures.

Senior unsecured notes. As of December 31, 2015, our long-term debt includes outstanding senior unsecured note obligations of $2,200.0 million, including $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”), $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the “2021 Notes”), $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”) and $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes,” and together with the 2019 Notes, the 2021 Notes and the 2022 Notes, the “Notes”). Interest on the Notes is payable semi-annually in arrears.

Prior to certain dates, we have certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. We may from time to time seek to retire or purchase our outstanding Notes through cash purchases and/or exchanges for other debt or equity securities, in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

The Notes are guaranteed on a senior unsecured basis by our material subsidiaries (the “Guarantors”). The indentures governing the Notes restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments;

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

On October 26, 2015, we, along with our Guarantors, and U.S. Bank National Association, as trustee, entered into supplemental indentures respecting amendments (the "Amendments") to the indentures governing the 2019 Notes, the 2021 Notes and the 2023 Notes (collectively, the "Consent Notes") following our receipt of requisite consents of the holders of the Consent Notes pursuant to consent solicitations that commenced on October 6, 2015. The Amendments amend the basket for secured credit facilities indebtedness in each of the indentures by (i) adding a provision that allows us to incur secured credit facilities indebtedness up to the amount of our borrowing base at the time of the incurrence, but not to exceed $1,525.0 million and (ii) adding, deleting or revising several related definitions in the indentures, which changes generally restrict our ability to incur second-lien indebtedness.

Senior secured revolving line of credit. We have a revolving credit facility (the "Second Amended Credit Facility") with an overall senior secured line of credit of $2,500.0 million as of December 31, 2015. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. On April 13, 2015, we entered into our third amendment to the Second Amended Credit Facility (the "Third Amendment"), which extended the maturity date of the Second Amended Credit Facility to April 13, 2020, provided that the 2019 Notes are retired or refinanced 90 days prior to the maturity of the 2019 Notes. In connection with the Third Amendment, the lenders under the Second Amended Credit Facility (the "Lenders") completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2015, resulting in a borrowing base decrease from $2,000.0 million to $1,700.0 million, and at that time, we increased the Lenders' aggregate elected commitment from $1,500.0 million to $1,525.0 million. On October 6, 2015, the Lenders completed their regular semi-annual redetermination of the borrowing base scheduled for October 1, 2015, resulting in a borrowing base decrease from $1,700.0 million to $1,525.0 million, which was equal to the Lenders' aggregate elected commitment. On February 23, 2016, the Lenders completed their regular semi-annual redetermination of the borrowing base scheduled for April 1, 2016, resulting in a decrease in the borrowing base and aggregate elected commitment from $1,525.0 million to $1,150.0 million. The next redetermination of the borrowing base is scheduled for October 1, 2016.

As of December 31, 2015, we had $138.0 million of borrowings at a weighted average interest rate of 1.9% and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility. As of December 31, 2015, including pro forma adjustments for the current borrowing base and the net proceeds from our public equity offering in February 2016, we had unused borrowing base committed capacity of $1,144.8 million. As of December 31, 2014, we had $500.0 million of borrowings at a weighted average interest rate of 1.9% and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base committed capacity of $994.8 million.

The Second Amended 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 Second Amended Credit Facility) to consolidated Interest Expense (as defined in the Second Amended Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that we maintain a Current Ratio (as defined in the Second Amended Credit Facility) of consolidated current assets (including unused borrowing base committed capacity and with exclusions as described in the Second

Amended Credit Facility) to consolidated current liabilities (with exclusions as described in the Second Amended Credit Facility) of no less than 1.0 to 1.0 as of the last day of any fiscal quarter.

The Second Amended Credit Facility contains customary events of default. If an event of default occurs and is continuing, the lenders may declare all amounts outstanding under the Second Amended Credit Facility to be immediately due and payable. We were in compliance with the financial covenants of the Second Amended Credit Facility as of December 31, 2015 and 2014. As of December 31, 2015, our consolidated EBITDAX was $820.2 million and our consolidated Interest Expense was $161.0 million, resulting in a ratio of 5.1 as compared to a minimum required ratio of 2.5. In addition, as of December 31, 2015, our consolidated current assets and consolidated current liabilities (as described above) were $1,607.4 million and $370.6 million, resulting in a Current Ratio of 4.3 as compared to a minimum required ratio of 1.0. Given the extended decline in commodity prices, we continue to closely monitor our financial covenants and do not anticipate a covenant violation in the next twelve months.

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2015:

Contractual obligations	Payments due by period				
	Total	Within 1 year	1-3 years	3-5 years	More than 5 years
	(In thousands)				
Senior unsecured notes[1]	$2,200,000	$—	$—	$400,000	$1,800,000
Interest payments on senior unsecured notes[1]	910,625	151,250	302,500	259,000	197,875
Borrowings under revolving credit facility[1]	138,000	—	—	138,000	—
Interest payments on borrowings under revolving credit facility[1]	185	185	—	—	—
Asset retirement obligations[2]	35,812	32	1,241	317	34,222
Operating leases[3]	26,548	7,737	10,090	8,721	—
Drilling rig commitments[3]	5,686	5,686	—	—	—
Volume commitment agreements[3]	448,406	4,117	98,619	106,037	239,633
Purchase agreements[3]	42,352	1,560	16,942	16,700	7,150
Total contractual cash obligations	$3,807,614	$170,567	$429,392	$928,775	$2,278,880

(1) See Note 9 to our audited consolidated financial statements for a description of our senior unsecured notes, revolving credit facility and related interest payments. As of December 31, 2015, we had $138.0 million of borrowings and $5.2 million of outstanding letters of credit issued under our Second Amended Credit Facility.

(2) Amounts represent our estimate of future asset retirement obligations ("ARO"). Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment. See Note 10 to our audited consolidated financial statements.

(3) See Note 17 to our audited consolidated financial statements for a description of our operating leases, drilling rig commitments, volume commitment agreements and purchase agreements.

Critical accounting policies and estimates

The discussion and analysis of our financial condition and results of operations are based upon our audited consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments used in preparation of our consolidated financial statements below. See Note 2 to our audited consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Method of accounting for oil and natural gas properties

Oil and natural gas exploration and development activities are accounted for using the successful efforts method. Under this method, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, pending

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determination of whether the well has found proved reserves. If an exploratory well does not find proved reserves, the costs of drilling the well are charged to expense. The costs of development wells are capitalized whether productive or nonproductive.

The provision for DD&A of oil and natural gas properties is calculated on a field-by-field basis using the unit-of-production method. All capitalized well costs and leasehold costs of proved properties are amortized on a unit-of-production basis over the remaining life of proved developed reserves and total proved reserves, respectively. Natural gas is converted to barrel equivalents at the rate of six thousand cubic feet of natural gas to one barrel of oil. The calculation for the unit-of-production DD&A method takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values.

Costs of retired, sold or abandoned properties that constitute a part of an amortization base (partial field) are charged or credited, net of proceeds, to accumulated DD&A unless doing so significantly affects the unit-of-production amortization rate for an entire field, in which case a gain or loss is recognized currently.

Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major betterments, replacements and renewals are capitalized to the appropriate property and equipment accounts. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized, net of salvage, at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

Unproved properties consist of costs incurred to acquire unproved leases, or lease acquisition costs. Lease acquisition costs are capitalized until the leases expire or when we specifically identify leases that will revert to the lessor, at which time we expense the associated lease acquisition costs. The expensing of the lease acquisition costs is recorded as impairment of oil and gas properties in our Consolidated Statement of Operations. Lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis.

For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Oil and natural gas reserve quantities and standardized measure of future net revenue

Our independent reserve engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the SEC rules allow us to disclose proved, probable and possible reserves, we have elected to disclose only proved reserves in this Annual Report on Form 10-K. The SEC's rules define proved reserves as the quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. Our independent reserve engineers and technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates are updated annually and consider recent production levels and other technical information about each field. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment.

Periodic revisions to the estimated reserves and related future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data or other economic factors. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Revenue recognition

Oil and gas revenue from our interests in producing wells is recognized when the product is delivered, at which time the customer has taken title and assumed the risks and rewards of ownership, and collectability is reasonably assured. Substantially all of our production is sold to purchasers under short-term (less than twelve month) contracts at market-based prices. The sales prices for oil and natural gas are adjusted for transportation and other related deductions. These deductions are based on contractual or historical data and do not require significant judgment. Subsequently, these revenue deductions are adjusted to reflect actual charges based on third-party documents. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations. As a result, we maintain a minimum amount of product inventory in storage.

Well services revenue is recognized when well completion or other well services have been performed or when well completion products have been delivered. OWS provides well services and sells well completion products primarily to OPNA. Midstream revenues consist primarily of revenues from salt water pipeline transport, salt water disposal and fresh water sales for OPNA's operated wells. Prior to the formation of OMS in 2013, the salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. The revenues related to OPNA's working interests are eliminated in consolidation, and only the revenues related to other working interest owners in OPNA's wells are included in our Consolidated Statement of Operations.

Impairment of proved properties

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected undiscounted future cash flows of our oil and natural gas properties and compare such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved oil and natural gas properties will be recorded. Please see "Overview" for a discussion of potential future impairment charges.

Impairment of unproved properties

The assessment of unproved properties to determine any possible impairment requires significant judgment. We assess our unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage.

We recognize impairment expense for unproved properties at the time when the lease term has expired or sooner based on management's periodic assessments. We consider the following factors in our assessment of the impairment of unproved properties:

- the remaining amount of unexpired term under our leases;
- our ability to actively manage and prioritize our capital expenditures to drill leases and to make payments to extend leases that may be close to expiration;
- our ability to exchange lease positions with other companies that allow for higher concentrations of ownership and development;
- our ability to convey partial mineral ownership to other companies in exchange for their drilling of leases; and
- our evaluation of the continuing successful results from the application of completion technology in the Bakken and Three Forks formations by us or by other operators in areas adjacent to or near our unproved properties.

Business combinations

We account for business combinations under the acquisition method of accounting. Accordingly, we recognize amounts for identifiable assets acquired and liabilities assumed equal to their estimated acquisition date fair values. Transaction and integration costs associated with business combinations are expensed as incurred.

We make various assumptions in estimating the fair values of assets acquired and liabilities assumed. As fair value is a market-based measurement, it is determined based on the assumptions that market participants would use. The most significant assumptions relate to the estimated fair values of proved and unproved oil and natural gas properties. The fair values of these properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of reserves, future operating and development costs, future commodity prices and a market-based weighted average cost of capital rate. The market-based weighted average cost of capital rate is subjected to

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additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and natural gas properties within the same regions, and use that data as a proxy for fair market value; for example, the amount a willing buyer and seller would enter into in exchange for such properties.

Any excess of the acquisition price over the estimated fair value of net assets acquired is recorded as goodwill. Any excess of the estimated fair value of net assets acquired over the acquisition price is recorded in current earnings as a gain on bargain purchase. Deferred taxes are recorded for any differences between the assigned values and the tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Asset retirement obligations

We record the fair value of a liability for a legal obligation to retire an asset in the period in which the liability is incurred with the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. For oil and gas properties, this is the period in which the well is drilled or acquired. The ARO represents the estimated amount we will incur to plug, abandon and remediate the properties at the end of their productive lives, in accordance with applicable state laws. The liability is accreted to its present value each period, and the capitalized costs are amortized on the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in our Consolidated Statement of Operations.

We determine the ARO by calculating the present value of estimated future cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future revisions, which could result in an increase to the existing ARO liability and could ultimately result in a higher potential impact on our operations and cash flows for settlement charges. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Derivatives

We record all derivative instruments on the Consolidated Balance Sheet as either assets or liabilities measured at their estimated fair value. The significant inputs used to estimate fair value are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. Derivative assets and liabilities arising from derivative contracts with the same counterparty are reported on a net basis, as all counterparty contracts provide for net settlement. We have not designated any derivative instruments as hedges for accounting purposes, and we do not enter into such instruments for speculative trading purposes. Gains and losses from valuation changes in commodity derivative instruments are reported under other income (expense) in our Consolidated Statement of Operations. Our cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements represent the cumulative gains and losses on our 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 our Consolidated Statement of Cash Flows.

Stock-based compensation

Restricted stock awards. We recognize compensation expense for all restricted stock awards made to employees and directors. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the requisite service period, which is generally the vesting period. The fair value of restricted stock grants is based on the value of our common stock on the date of grant. Assumptions regarding forfeiture rates are subject to change. Any such changes could result in different valuations and thus impact the amount of stock-based compensation expense recognized. Stock-based compensation expense recorded for restricted stock awards is included in general and administrative expenses on our Consolidated Statement of Operations.

Performance share units. We recognize compensation expense for our performance share units (“PSUs”) granted to our officers. Stock-based compensation expense is measured at the grant date based on the fair value of the award and is recognized as expense on a straight-line basis over the performance period, which is generally the vesting period. The fair value of the PSUs is based on the calculation derived from a Monte Carlo simulation model. The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probable assessment (see Note 12 to our audited consolidated financial statements for a description of the inputs used in this model). Stock-based compensation expense recorded for PSUs is included in general and administrative expenses on our Consolidated Statement of Operations.

Income taxes

Our provision for taxes includes both federal and state taxes. We record our federal income taxes in accordance with accounting for income taxes under GAAP, which results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences between the book carrying amounts and the tax basis of assets and liabilities. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

We apply significant judgment in evaluating our tax positions and estimating our provision for income taxes. During the ordinary course of business, there are many transactions and calculations for which the ultimate tax determination is uncertain. The actual outcome of these future tax consequences could differ significantly from our estimates, which could impact our financial position, results of operations and cash flows.

We also account for uncertainty in income taxes recognized in the financial statements in accordance with GAAP by prescribing a recognition threshold and measurement attribute for a tax position taken or expected to be taken in a tax return. Authoritative guidance for accounting for uncertainty in income taxes requires that we recognize the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more-likely-than-not threshold, the amount recognized in the financial statements is the largest benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Recent accounting pronouncements

Revenue recognition. In May 2014, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (“ASU 2014-09”). The objective of ASU 2014-09 is greater consistency and comparability across industries by using a five-step model to recognize revenue from customer contracts. ASU 2014-09 also contains some new disclosure requirements under GAAP. In August 2015, the FASB issued Accounting Standards Update No. 2015-14, Deferral of the Effective Date (“ASU 2015-14”). ASU 2015-14 defers the effective date of the new revenue standard by one year, making it effective for annual reporting periods beginning after December 15, 2017, including interim periods within that reporting period. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

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

Extraordinary items. In January 2015, the FASB issued Accounting Standards Update No. 2015-01, Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items (“ASU 2015-01”). ASU 2015-01 removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed. ASU 2015-01 is effective for fiscal years beginning after December 15, 2015, including interim periods within those years. We do not expect the adoption of this guidance to have a material impact on our financial position, cash flows or results of operations.

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

Business combinations. In September 2015, the FASB issued Accounting Standards Update No. 2015-16, Simplifying the Accounting for Measurement-Period Adjustments (“ASU 2015-16”), which eliminates the requirement for an acquirer in a business combination to restate prior period financial statements for measurement period adjustments. ASU 2015-16 requires that the cumulative impact of measurement period adjustments on current and prior periods be recognized in the reporting period in which the adjustment amount is determined. ASU 2015-16 is effective for fiscal years beginning after December 15,

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2015, including interim periods within those years. We are currently evaluating the effect that adopting this guidance will have on our financial position, cash flows and results of operations.

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

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2015, 2014 and 2013. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and in the past, we have tended to experience inflationary pressure on the cost of midstream and oilfield services and equipment as increasing oil and natural gas prices increased drilling activity in our areas of operations. In 2015, we experienced service cost reductions as a result of lower oil prices and decreased drilling activity in the Williston Basin.

Off-balance sheet arrangements

Currently, we do not have any off-balance sheet arrangements as defined by the SEC. In the ordinary course of business, we enter into various commitment agreements and other contractual obligations, some of which are not recognized in our consolidated financial statements in accordance with GAAP. See "Obligations and commitments" above and Note 17 to our audited consolidated financial statements for a description of our commitments and contingencies.

Non-GAAP Financial Measures

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

Adjusted EBITDA

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

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

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	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Net income (loss)	$(40,248)	$506,877	$227,959
Gain on sale of properties	—	(186,999)	—
Net (gain) loss on derivative instruments	(210,376)	(327,011)	35,432
Derivative settlements[1]	370,410	6,774	(8,133)
Interest expense, net of capitalized interest	149,648	158,390	107,165
Depreciation, depletion and amortization	485,322	412,334	307,055
Impairment of oil and gas properties	46,109	47,238	1,168
Exploration expenses	2,369	3,064	2,260
Rig termination	3,895	—	—
Stock-based compensation expenses	25,272	21,302	11,982
Income tax (benefit) expense	(16,123)	307,591	135,058
Other non-cash adjustments	3,956	3,284	1,910
Adjusted EBITDA	$820,234	$952,844	$821,856
Net cash provided by operating activities	$359,815	$872,516	$697,856
Derivative settlements[1]	370,410	6,774	(8,133)
Interest expense, net of capitalized interest	149,648	158,390	107,165
Exploration expenses	2,369	3,064	2,260
Rig termination	3,895	—	—
Deferred financing costs amortization and other	(12,299)	(11,028)	(4,248)
Current tax (benefit) expense	(9)	134	475
Changes in working capital	(57,551)	(80,290)	24,571
Other non-cash adjustments	3,956	3,284	1,910
Adjusted EBITDA	$820,234	$952,844	$821,856

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

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

Exploration and Production

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Income (loss) before income taxes	$(118,970)	$779,591	$331,781
Gain on sale of properties	—	(186,999)	—
Net (gain) loss on derivative instruments	(210,376)	(327,011)	35,432
Derivative settlements[1]	370,410	6,774	(8,133)
Interest expense, net of capitalized interest	149,648	158,390	107,165
Depreciation, depletion and amortization	479,693	406,960	304,388
Impairment of oil and gas properties	46,109	47,238	1,168
Exploration expenses	2,369	3,064	2,260
Rig termination	3,895	—	—
Stock-based compensation expenses	24,762	20,701	11,602
Other non-cash adjustments	3,719	2,314	1,371

Adjusted EBITDA	$751,259	$911,022	$787,034

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

Well Services

	Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Income before income taxes	$49,197	$70,953	$56,338
Depreciation, depletion and amortization	19,073	14,080	7,150
Stock-based compensation expenses	1,952	1,658	969
Other non-cash adjustments	237	970	539
Adjusted EBITDA	$70,459	$87,661	$64,996

Midstream Services

	Year Ended December 31,		
	2015	2014	2013[(1)]
	(In thousands)		
Income before income taxes	$59,867	$22,730	$17,509
Depreciation, depletion and amortization	5,764	3,744	2,780
Stock-based compensation expenses	692	—	—
Adjusted EBITDA	$66,323	$26,474	$20,289

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(1) Our midstream business segment (OMS) was not formed until the first quarter of 2013.

Adjusted Net Income and Adjusted Diluted Earnings Per Share

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

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