Oasis Petroleum Inc.
Form 10-K
February 27, 2014
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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, 2013
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. ¨

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: $3,636,448,683

Number of shares of registrant’s common stock outstanding as of February 21, 2014: 101,216,201

Documents Incorporated By Reference:

Portions of the registrant’s definitive proxy statement for its 2014 Annual Meeting of Stockholders, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2013, are incorporated by reference into Part III of this report for the year ended December 31, 2013.

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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, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this 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," "predict," "potential," "project" and simila 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 well services and midstream companies;
- 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, including our recent acquisitions of oil and gas properties in our West Williston and East Nesson project areas, 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") is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the North Dakota and Montana regions of the Williston Basin. As of December 31, 2013, we have accumulated 515,314 net leasehold acres in the Williston Basin. 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 in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the large-scale 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 2013, we completed and placed on production 136 gross operated wells in the Williston Basin. We have built our Williston Basin assets primarily through acquisitions and development in our three primary project areas: West Williston, East Nesson and Sanish.

DeGolyer and MacNaughton, our independent reserve engineers, estimated our net proved reserves to be 227.9 MMBoe as of December 31, 2013, of which 54% were classified as proved developed and of which 87% were oil. The following table presents summary data for each of our primary project areas as of December 31, 2013:

		Productive Bakken and Three Forks Wells		Estimated net proved reserves as of December 31, 2013		2013 Average daily production
Project area	Net acreage	Gross	Net	MMBoe	% Developed	Boe/d
West Williston	361,626	462	253.4	154.0	52 %	21,170
East Nesson	145,345	254	123.7	65.3	53 %	10,054
Sanish	8,343	323	25.0	8.6	97 %	2,680
Total	515,314	1,039	402.1	227.9	54 %	33,904

Our history

Oasis Petroleum Inc. was incorporated in February 2010 pursuant to the laws of the State of Delaware to become a holding company for Oasis Petroleum LLC ("OP LLC"), our predecessor, which was formed as a Delaware limited liability company in February 2007. We completed our initial public offering ("IPO") in June 2010. In connection with our IPO and related corporate reorganization, we acquired all of the outstanding membership interests in OP LLC in exchange for shares of our common stock. Oasis Petroleum North America LLC ("OPNA") conducts our exploration and production activities and owns our proved and unproved oil and natural gas properties. In 2011, we formed Oasis Well Services LLC ("OWS"), which provides well services to OPNA, and Oasis Petroleum Marketing LLC ("OPM"), which provides marketing services to OPNA. In 2013, we formed Oasis Midstream Services LLC ("OMS"), which provides midstream services to OPNA. As part of the formation of OMS, the Company transferred substantially all of its salt water disposal and other midstream assets from OPNA to OMS.

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:

- Aggressively develop our Williston Basin leasehold position. We intend to continue to drill and develop our acreage position to maximize the value of our resource potential. During 2013, we completed and brought on production 136 gross (106.1 net) operated Bakken and Three Forks wells in the Williston Basin. As of December 31, 2013, we had 41 gross operated wells waiting on completion and 18 gross operated wells drilling in the Bakken and Three Forks formations. Our 2014 drilling plan contemplates completing approximately 205 gross (147.8 net) operated wells in our project areas. We believe we have the ability to increase or decrease the number of wells drilled during 2014 based on market conditions and program results.
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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 converting early-stage resource conversion opportunities into cost-efficient development projects. We believe the magnitude and concentration of our acreage within our project areas provide us with the opportunity to capture economies of scale, including the ability to drill multiple

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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 are increasing OWS in 2014 to two fracturing fleets, and we expect OWS and OMS to continue to provide capital savings and lower our operated well costs 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 believe these techniques have significantly evolved over the last several years, resulting in increased initial production rates and recoverable hydrocarbons per well through the implementation of techniques such as drilling longer laterals and more tightly spaced fracturing stimulation stages. 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.
- 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. During 2013, we acquired, through four distinct transactions, approximately 161,000 net acres in and around our West Williston and East Nesson project areas (the "West Williston Acquisition" and the "East Nesson Acquisitions," respectively). 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.
- Maintain financial flexibility. We are committed to maintaining sufficient liquidity and reasonable leverage levels. As of December 31, 2013, we had $335.6 million of borrowings and $5.2 million of outstanding letters of credit under our revolving credit facility and $1,251.1 million of liquidity available, including $91.9 million in cash and $1,159.2 million available under our revolving credit facility. This liquidity position, along with internally generated cash flows, will provide additional financial flexibility as we continue to develop our acreage position in the Williston Basin. We also currently believe we have access to the public equity and debt markets, and we intend to maintain a balanced capital structure by prudently raising proceeds from future offerings as additional capital needs arise.

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. As of December 31, 2013, substantially all of our 515,314 net leasehold acres in the Williston Basin were highly prospective in the Bakken and Three Forks formations and 87% of our 227.9 MMBoe estimated net proved reserves in this area were comprised of oil. We increased our operated drilling spacing units by 123 through acquisitions, acreage additions and trades during 2013. In addition, we have 422,386 net acres held-by-production as of December 31, 2013. We believe our acreage is one of the largest concentrated leasehold positions that is prospective in the Bakken and Three Forks formations, and much of our acreage is in areas of significant drilling activity by other exploration and production companies. We expect that the scale and concentration of our acreage will enable us to continue to reduce our drilling and completion costs and improve operational efficiency as we continue in full development mode and drill more wells on pads utilizing simultaneous operations in 2014.
- 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 is operated by us. We plan to complete 205 gross (147.8 net) operated wells in the Williston Basin in 2014.
- 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.
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Incentivized management team. As of December 31, 2013, our executive officers owned over 4% of our outstanding common stock, and an average of 57% of their overall compensation was in long-term equity-based incentive awards. 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. We expect to operate approximately 94% of our net drilling locations. As of December 31, 2013, 94% of our estimated net proved reserves were attributable to properties that we expect to operate. Approximately 95% of our 2014 drilling and completion capital

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expenditure budget is related to operated wells. As of December 31, 2013, our average working interest in our operated and non-operated potential drilling locations was 68% and 10%, respectively. 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 investment to drive down operating costs and increase gas production and oil price realizations.

Our operations

Estimated net proved reserves

The table below summarizes our estimated net proved reserves and related PV-10 at December 31, 2013, 2012 and 2011 for each of our project areas based on reports prepared by DeGolyer and MacNaughton, our independent reserve engineers. In preparing its reports, DeGolyer and MacNaughton evaluated properties representing all of our PV-10 at December 31, 2013, 2012 and 2011 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 were determined using the preceding twelve months' unweighted arithmetic average of the first-day-of-the-month prices and do not include probable or possible reserves. The information in the following table does not give any effect to or reflect our commodity derivatives. 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.

Project area	At December 31, 2013		At December 31, 2012		At December 31, 2011	
	Proved reserves (MMBoe)	PV-10[(1)] (in millions)	Proved reserves (MMBoe)	PV-10[(1)] (in millions)	Proved reserves (MMBoe)	PV-10[(1)] (in millions)
Williston Basin:						
West Williston	154.0	$3,571.0	94.6	$2,066.6	51.6	$1,242.6
East Nesson	65.3	1,663.4	41.4	975.6	21.1	479.1
Sanish	8.6	252.5	7.3	202.1	6.0	182.0
Total Williston Basin	227.9	$5,486.9	143.3	$3,244.3	78.7	$1,903.7

(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 properties. 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.

Estimated net proved reserves at December 31, 2013 were 227.9 MMBoe, a 59% increase from estimated net proved reserves of 143.3 MMBoe at December 31, 2012 primarily as a result of our 2013 drilling program and well completions as well as the West Williston Acquisition and the East Nesson Acquisitions during the year ended December 31, 2013. Our proved developed reserves increased 52.1 MMBoe, or 74%, to 122.1 MMBoe for the year ended December 31, 2013 from 70.0 MMBoe for the year ended December 31, 2012, primarily due to our 2013 drilling program, including the completion of 136 gross (106.1 net) operated wells, and our property acquisitions. Our proved undeveloped reserves increased to 105.8 MMBoe for the year ended December 31, 2013 from 73.3 MMBoe for the year ended December 31, 2012 primarily due to our 2013 drilling program and property acquisitions.

Estimated net proved reserves at December 31, 2012 were 143.3 MMBoe, an 82% increase from estimated net proved reserves of 78.7 MMBoe at December 31, 2011 primarily as a result of our 2012 drilling program and well completions. Our proved developed reserves increased 34.2 MMBoe, or 95%, to 70.0 MMBoe for the year ended December 31, 2012 from 35.8 MMBoe for the year ended December 31, 2011, primarily due to our 2012 drilling program, including the completion of 117 gross (95.8 net) operated wells. Our proved undeveloped reserves increased to 73.3 MMBoe for the year ended December 31, 2012 from 42.9 MMBoe for the year ended December 31, 2011 primarily due to our 2012 drilling program.

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The following table sets forth more information regarding our estimated net proved reserves at December 31, 2013, 2012 and 2011:

	At December 31, 2013	2012	2011
Reserves Data[(1)]:			
Estimated proved reserves:			
Oil (MMBbls)	198.6	128.1	69.1
Natural gas (Bcf)	176.0	91.5	57.9
Total estimated proved reserves (MMBoe)	227.9	143.3	78.7
Percent oil	87 %	89 %	88 %
Estimated proved developed reserves:			
Oil (MMBbls)	106.8	62.6	31.8
Natural gas (Bcf)	92.2	44.7	24.5
Total estimated proved developed reserves (MMBoe)	122.1	70.0	35.8
Percent proved developed	54 %	49 %	46 %
Estimated proved undeveloped reserves:			
Oil (MMBbls)	91.8	65.5	37.3
Natural gas (Bcf)	83.8	46.8	33.4
Total estimated proved undeveloped reserves (MMBoe)	105.8	73.3	42.9
PV-10 (in millions)[(2)]	$5,486.9	$3,244.3	$1,903.7
Standardized Measure (in millions)[(3)]	$3,727.6	$2,259.9	$1,319.5

(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 $96.96/Bbl for oil and $3.66/MMBtu for natural gas, $94.68/Bbl for oil and $2.75/MMBtu for natural gas and $96.23/Bbl for oil and $4.12/MMBtu for natural gas for the years ended December 31, 2013, 2012 and 2011, 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.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, 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 properties. 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.

(3) 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 (if applicable), discounted at 10% per annum to reflect timing of future cash flows.

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 percent. 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.

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The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2013, 2012 and 2011:

	At December 31,		
	2013	2012	2011
		(In millions)	
PV-10	$5,486.9	$3,244.3	$1,903.7
Present value of future income taxes discounted at 10%	1,759.3	984.4	584.2
Standardized Measure of discounted future net cash flows	$3,727.6	$2,259.9	$1,319.5

The PV-10 of our estimated net proved reserves at December 31, 2013 was $5,486.9 million, a 69% increase from PV-10 of $3,244.3 million at December 31, 2012. This increase was mainly due to an increase in reserves, higher commodity price assumptions and a reduction in future development costs year over year.

Estimated future net revenues

The following table sets forth the estimated future net revenues, excluding derivative contracts, 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, 2013, 2012 and 2011:

	At December 31,		
	2013	2012	2011
	(In millions, except price data)		
Future net revenues	$11,685.6	$7,077.4	$4,034.9
Present value of future net revenues:			
Before income tax (PV-10)	5,486.9	3,244.3	1,903.7
After income tax (Standardized Measure)	3,727.6	2,259.9	1,319.5
Benchmark oil price ($/Bbl)[1]	$96.96	$94.68	$96.23

(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 $96.96/Bbl for oil and $3.66/MMBtu for natural gas, $94.68/Bbl for oil and $2.75/MMBtu for natural gas and $96.23/Bbl for oil and $4.12/MMBtu for natural gas for the years ended December 31, 2013, 2012 and 2011, 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 net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2013, 2012 and 2011 are based on costs in effect at December 31 of each year and the twelve-month unweighted arithmetic average of the first-day-of-the-month price for January through December of such year, without giving effect to derivative transactions, and are held constant throughout the life of the properties. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Proved undeveloped reserves

At December 31, 2013, we had approximately 105.8 MMBoe of proved undeveloped reserves as compared to 73.3 MMBoe at December 31, 2012.

The following table summarizes the changes in our proved undeveloped reserves during 2013 (in MBoe):

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At December 31, 2012	73,294
Extensions, discoveries and other additions	23,903
Purchases of minerals in place	26,849
Sales of minerals in place	—
Revisions of previous estimates	1,716
Conversion to proved developed reserves	(19,978)
At December 31, 2013	105,784

During 2013, we spent a total of $398.5 million related to the development of proved undeveloped reserves, $53.6 million of which was spent on proved undeveloped reserves that still remain proved undeveloped at year-end. The remaining $344.9 million resulted in the conversion of 19,978 MBoe of proved undeveloped reserves, or 27% of our proved undeveloped reserves balance at the beginning of 2013, to proved developed reserves. We added 23,903 MBoe of proved undeveloped reserves across all three of our project areas as a result of our 2013 operated and non-operated drilling program. We participated in 250 gross (115.1 net) wells that were completed and brought on production during 2013. In addition, we purchased 26,849 MBoe of proved undeveloped reserves primarily as a result of the West Williston Acquisition. In 2013, we also had a net positive revision of 1,716 MBoe, or 2% of our December 31, 2012 proved undeveloped reserves balance as a result of several immaterial changes, including well performances, working interests, operating costs and realized prices.

We expect to develop all of our proved undeveloped reserves as of December 31, 2013 within five years of their initial booking.

Independent petroleum engineers

Our estimated net proved reserves and related future net revenues, PV-10 and Standardized Measure at December 31, 2013, 2012 and 2011 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 and Moscow. 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 Petroleum Engineer in the State of Texas with more than 35 years of experience in oil and gas reservoir studies and reserve evaluations. He graduated with a Bachelor of Science degree in Petroleum Engineering from Texas A&M University in 1974 and he is a member of the International Society of Petroleum Engineers and the American Association of Petroleum Geologists. 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.

In order to establish reasonable certainty with respect to our estimated net proved reserves, DeGolyer and MacNaughton employed technologies including, but not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available down hole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and seismic data related to the Bakken formation were used to estimate original oil in place. In areas where estimated proved reserves were attributed to more than one well per spacing unit, the estimated original oil in place was used to calculate reasonable estimated recovery factors based on experience with similar reservoirs where similar drilling and completion techniques have been employed.

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 20 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:

- 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 the supply of oil could impact oil prices in the United States if the supply outstrips domestic demand. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil or 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.

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."

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	Year Ended December 31,		
	2013	2012	2011
Net production volumes:			
Oil (MBbls)	11,133	7,533	3,732
Natural gas (MMcf)	7,450	4,146	1,092
Oil equivalents (MBoe)	12,375	8,224	3,914
Average daily production (Boe/d)	33,904	22,469	10,724
Average sales prices:			
Oil, without derivative settlements (per Bbl)	$92.34	$85.22	$86.18
Oil, with derivative settlements (per Bbl)(1)	91.61	86.09	85.15
Natural gas (per Mcf)(2)	6.78	6.52	8.02
Costs and expenses (per Boe of production):			
Lease operating expenses(3)	$7.65	$6.68	$8.36
Marketing, transportation and gathering expenses	2.09	1.13	0.34
Production taxes	8.12	7.66	8.65
Depreciation, depletion and amortization	24.81	25.14	19.16
General and administrative expenses	6.09	6.95	7.52

(1) 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.

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

(3) For the year ended December 31, 2011, lease operating expenses exclude marketing, transportation and gathering expenses to conform such amounts to current year classifications.

Net production volumes for the year ended December 31, 2013 were 12,375 MBoe, a 50% increase from net production of 8,224 MBoe for the year ended December 31, 2012. Our net production volumes increased 4,151 MBoe over 2012 due to a successful operated and non-operated drilling and completion program and acquisitions of producing properties. Average oil sales prices, without derivative settlements, increased by $7.12/Bbl, or 8%, to an average of $92.34/Bbl for the year ended December 31, 2013 as compared to the year ended December 31, 2012. Giving effect to our derivative transactions in both periods, our oil sales prices increased $5.52/Bbl to $91.61/Bbl for the year ended December 31, 2013 from $86.09/Bbl for the year ended December 31, 2012.

Net production volumes for the year ended December 31, 2012 were 8,224 MBoe, a 110% increase from net production of 3,914 MBoe for the year ended December 31, 2011. Our net production volumes increased 4,310 MBoe over 2011 due to a successful operated and non-operated drilling and completion program. Average oil sales prices, without derivative settlements, decreased by $0.96/Bbl, or 1%, to an average of $85.22/Bbl for the year ended December 31, 2012 as compared to the year ended December 31, 2011. Giving effect to our derivative transactions in both periods, our oil sales prices increased $0.94/Bbl to $86.09/Bbl for the year ended December 31, 2012 from $85.15/Bbl for the year ended December 31, 2011.

The following table sets forth information regarding our average daily production for the years ended December 31, 2013, 2012 and 2011:

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	Average daily production for the years ended December 31,								
	2013			2012			2011		
	Bbls	Mcf	Boe	Bbls	Mcf	Boe	Bbls	Mcf	Boe
Williston Basin:									
West Williston	18,815	14,127	21,170	13,904	8,152	15,263	6,426	1,278	6,639
East Nesson	9,229	4,951	10,054	4,586	2,106	4,936	2,333	430	2,404
Sanish	2,458	1,333	2,680	2,091	1,070	2,270	1,467	750	1,592
Total Williston Basin	30,502	20,411	33,904	20,581	11,328	22,469	10,226	2,458	10,635
Other[1]	—	—	—	—	—	—	—	533	89
Total	30,502	20,411	33,904	20,581	11,328	22,469	10,226	2,991	10,724

(1) Represents data relating to our properties in the Barnett shale, which we sold in November 2011.

Productive wells

The following table presents the total gross and net productive wells by project area as of December 31, 2013:

	Total wells		Bakken and Three Forks		Operated Bakken and Three Forks wells	
Project area	Gross	Net	Gross	Net	Gross	Net
West Williston	607	352.8	462	253.4	311	240.8
East Nesson	254	123.7	254	123.7	145	115.0
Sanish	323	25.0	323	25.0	—	—
Total	1,184	501.5	1,039	402.1	456	355.8

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, 2013 for each of our project areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary.

	Developed acres		Undeveloped acres		Total acres	
Project area	Gross	Net	Gross	Net	Gross	Net
West Williston	387,605	291,265	108,441	70,361	496,046	361,626
East Nesson	222,052	87,449	177,295	57,896	399,347	145,345
Sanish	41,528	8,343	—	—	41,528	8,343
Total	651,185	387,057	285,736	128,257	936,921	515,314

We increased our acreage that is held-by-production to 422,386 net acres at December 31, 2013 from 264,595 net acres at December 31, 2012.

Undeveloped acreage

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2013 that will expire over the next three years by project area unless production is established within the spacing units covering the acreage prior to the expiration dates:

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	Expiring 2014		Expiring 2015		Expiring 2016	
	Gross	Net	Gross	Net	Gross	Net
West Williston	13,983	11,977	9,722	7,182	9,427	3,366
East Nesson	50,715	3,209	74,984	20,338	32,267	11,353
Sanish	—	—	—	—	—	—
Total	64,698	15,186	84,706	27,520	41,694	14,719

Drilling and completion activity

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011. Gross wells reflect the sum of all productive and dry wells, operated and non-operated, in which we own an 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,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Oil	188	75.3	193	89.9	128	48.4
Gas	—	—	—	—	—	—
Dry[(1)]	—	—	2	1.9	—	—
Total development wells	188	75.3	195	91.8	128	48.4
Exploratory wells:						
Oil	62	39.8	38	15.7	9	6.2
Gas	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	62	39.8	38	15.7	9	6.2
Total wells	250	115.1	233	107.5	137	54.6

(1) In 2012, we had two gross development dry hole wells as a result of mechanical failures. Replacement wells were drilled in the same drilling spacing units and were productive wells.

Our drilling activity has increased each year since our inception. Exploration wells in 2011 primarily focused on delineation and appraisal of the Bakken formation in our West Williston and East Nesson areas. In 2012 and 2013, we continued this focus on delineation, resulting in substantially all of our acreage being delineated in the Bakken and Three Forks formations as of December 31, 2013. We also continued to participate in a number of wells on a non-operated basis.

We did not drill any dry hole wells in 2013. In 2012, we had two gross development dry hole wells as a result of mechanical failures. Replacement wells were drilled in the same drilling spacing units and were productive wells. In 2012 and 2011, we allocated a portion of the costs for a well that was unsuccessful due to mechanical complications in the Three Forks formation to exploratory dry hole expense. The well was successfully plugged back and completed in the Bakken formation.

Consistent with our 2014 capital plan, we expect to continue to focus on drilling in the Bakken and Three Forks formations.

Capital expenditure budget

In 2013, we spent $2,506.3 million on capital expenditures, which represented a 118% increase over the $1,148.6 million spent during 2012. Excluding the West Williston Acquisition and the East Nesson Acquisitions in 2013 totaling $1,551.7 million, we spent $954.6 million, which represented a 17% decrease compared to 2012. The reduction, excluding the impact of the acquisitions, was primarily due to lower well capital costs partially offset by more drilling and completion activity. 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.”

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Our total 2014 capital expenditure budget is $1,425 million, which includes $1,367 million for exploration and production ("E&P") capital expenditures and $58 million for non-E&P capital expenditures. Our planned capital expenditures primarily consist of:

- $1,250 million of drilling and completion (including production-related equipment) capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS);
- $60 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems;
- $25 million for maintaining and expanding our leasehold position;
- $19 million for field facilities and other miscellaneous E&P capital expenditures;
- $13 million for collection of subsurface reservoir data;
- $35 million for OWS, including district tools; and
- $23 million for other non-E&P capital, including items such as administrative capital and capitalized interest.

While we have budgeted $1,425 million for these purposes, the ultimate amount of capital we will expend may fluctuate materially based on market conditions and the success of our drilling results as the year progresses. Additionally, if we acquire additional acreage, as was the case in 2013, 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."

Our core project areas

Williston Basin

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 exploration and 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 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. The Williston Basin is now one of the most actively drilled unconventional oil resource plays in the United States, with approximately 192 rigs drilling in the basin, including 182 in North Dakota and 10 in Montana, based on Anderson Reports' weekly rig count dated January 7, 2014. 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 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 that may add incremental reserves to our existing leasehold positions. 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, 2013 consisted of 515,314 net acres. Our estimated net proved reserves in the Williston Basin were 227.9 MMBoe at December 31, 2013. Of our estimated net proved reserves in the Williston Basin, approximately 122.1 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, 105.8 MMBoe were proved undeveloped reserves, all of which consisted of Bakken and Three

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Forks wells to be drilled with more recent completion techniques. We expect that all of our potential drilling locations in each of our project areas will be drilled and completed using completion techniques similar to those we currently employ. As of December 31, 2013, we had a total of 501.5 net operated and non-operated producing wells and 449.7 net operated producing wells in the Williston Basin. We had average daily production of 33,904 net Boe/d for the year ended December 31, 2013 in the Williston Basin. During 2013, our Bakken and Three Forks wells produced a daily average of 33,183 net Boe/d with 402.1 net producing wells on December 31, 2013. Accordingly, our 402.1 net Bakken and Three Forks wells were responsible for 98% of our average daily production during 2013. As of December 31, 2013, our working interest for all producing wells averaged 42% and in the wells we operate was approximately 80%. As of December 31, 2013, we were drilling or completing 92 gross (40.3 net) wells in the Williston Basin. We participated in 250 gross (115.1 net) wells that were completed and brought on production during 2013.

Currently, we estimate our capital expenditures for 2014 will be $1,425 million, which includes completing 205 gross (147.8 net) horizontal operated wells, participating in 7.7 net non-operated wells that are expected to be completed and brought on production, construction of infrastructure to support production and leasehold acquisitions. Since most of this capital is expected to be spent on horizontal drilling in the Bakken and Three Forks formations, we expect that the proportion of our production from these formations will grow in the future.

Our Williston Basin activities are evaluated in three primary areas of operations: West Williston, East Nesson and Sanish. In January 2014, we executed a purchase and sale agreement for the sale of certain assets in and around our Sanish project area.

West Williston

We control 361,626 net acres in the West Williston project area, primarily in Williams and McKenzie counties in North Dakota and Roosevelt and Richland counties in Montana. We had average daily production of 21,170 net Boe/d for the year ended December 31, 2013, 97% of which was produced from the Bakken and Three Forks formations and the remainder from other conventional formations. As of December 31, 2013, we had an average working interest of 58% and operated 95% of our 352.8 net producing wells in the West Williston project area. As of December 31, 2013, we operated 95% of our 253.4 net producing Bakken and Three Forks wells in the West Williston project area.

During the year ended December 31, 2013, our total completions were 89 gross (62.1 net) horizontal Bakken and Three Forks wells in the West Williston project area. As of December 31, 2013, we were participating in the drilling or completion of 52 gross (24.3 net) wells in this project area. We have budgeted $727 million in capital expenditures in the West Williston project area in 2014 for the completion of 123 gross (85.1 net) operated wells and 5.2 net non-operated wells.

East Nesson

We control 145,345 net acres in the East Nesson project area, primarily in Mountrail and Burke counties in North Dakota. We had average daily production of 10,054 net Boe/d for the year ended December 31, 2013, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2013, we had an average working interest of 49% and operated 93% of our 123.7 net producing wells in the East Nesson project area, all of which are producing out of the Bakken and Three Forks formations.

During the year ended December 31, 2013, our total completions were 92 gross (47.8 net) horizontal Bakken and Three Forks wells in the East Nesson project area. As of December 31, 2013, we were participating in the drilling or completion of 25 gross (14.6 net) wells in this project area. We have budgeted $520 million in capital expenditures in the East Nesson project area in 2014 for the completion of 82 gross (62.7 net) operated wells and 1.5 net non-operated wells.

Sanish

We have 8,343 net acres in the Sanish project area, all of which are located in Mountrail County in North Dakota. We had average daily production of 2,680 net Boe/d for the year ended December 31, 2013, all of which was produced from the Bakken and Three Forks formations. As of December 31, 2013, we had an average working interest of 8% in our 25.0 net wells in the Sanish project area. Our properties in this project area are entirely operated by other operators, the largest of which are Whiting Petroleum Corporation and Fidelity Exploration.

During the year ended December 31, 2013, our total completions were 69 gross (5.2 net) horizontal Bakken and Three Forks wells in the Sanish project area. As of December 31, 2013, we were participating in the drilling or completion of 15 gross (1.4 net) wells in this project area. We have budgeted $3 million in capital expenditures in the Sanish project area in 2014 for the completion of 1.0 net non-operated wells. As of December 31, 2013, certain assets in and around our Sanish project area were held for sale, and in January 2014, we executed a purchase and sale agreement for the sale of these assets for approximately

$333.0 million, subject to customary post-close adjustments (see Note 7 and Note 18 to our audited Consolidated Financial Statements for a description of our assets held for sale and subsequent divestiture of such assets).

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 2013, oil production in North Dakota was approximately 923,000 barrels per day compared to approximately 769,000 barrels per day in December 2012. According to the North Dakota Pipeline Authority website's data dated January 22, 2014, there were approximately 583,000 barrels per day of crude oil pipeline transportation capacity in the Williston Basin as of December 31, 2013. In addition, there was approximately 965,000 barrels per day of specifically dedicated railcar transportation capacity as of December 31, 2013. In 2013, we continued to sell a significant amount of our crude oil production from our West Williston and East Nesson project areas 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, 2013, we were flowing approximately 75% of our gross operated oil production through these gathering systems. We will continue to implement wellhead gathering of crude oil in 2014 with the implementation of gathering connections for our recently acquired wells in our West Williston project area and also connections of infill wells throughout the Williston Basin, which we expect will increase the gross operated oil production that will flow on these systems to over 80% by mid-year 2014.

Recent expansion of both rail and pipeline facilities has reduced the previous constraint on oil transportation out of the Williston Basin and improved netback pricing received at the lease. However, oil from Canada has continued to flow into the existing downstream pipeline infrastructure that services Midwest refineries and affects Williston Basin pipeline sales demand into those Midwest refineries. Both Canadian oil and Williston Basin crude oil continue to utilize these pipeline facilities, and excess pipeline capacity is available due to the current balance between rail and pipeline capacity. 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."

In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows.

For the years ended December 31, 2013 and 2012, sales to Musket Corporation accounted for approximately 11% and 10% of our total sales, respectively. For the year ended December 31, 2011, sales to Texon L.P., Plains All American Pipeline, L.P. and Enserco Energy Inc. accounted for approximately 18%, 16% and 15%, respectively, of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2013, 2012 and 2011. 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 our project areas.

As of December 31, 2013, we sold a substantial majority of our oil and condensate through bulk sales from 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. Crude oil produced and sold in the Williston Basin has historically sold at a discount to the price quoted for NYMEX West Texas Intermediate ("WTI") crude oil 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. In the first half of 2012, price differentials were at or above the historical average discount range of 10% to 15% to the price quoted for WTI crude oil due to production growth in the Williston Basin combined with refinery and transportation constraints. In the third quarter of 2012, our average price differentials relative to WTI began to narrow, primarily due to transportation capacity additions, including expanded rail infrastructure and pipeline

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expansions, outpacing production growth. In the fourth quarter of 2012 and into the first quarter of 2013, average price differentials continued to narrow, primarily due to our ability to access premium coastal markets by rail. As the premium 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, our average price differentials to WTI continued to increase due to the pipeline market weakening as a result of refinery down time and increased United States and Canadian production. 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.

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, the condition of the United States economy, oil supply in the United States, 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—A substantial or extended decline 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 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 decrease, 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 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

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Winter weather conditions and lease stipulations can limit or temporarily halt our drilling 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.

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.

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

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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 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. 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 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 during 2012 and 2013, and we expect to continue to incur these increased costs in order to remain in compliance.

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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 and comprehensive 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 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 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 administrative, civil and criminal penalties, the imposition of remedial obligations 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 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, as amended (“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 found 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, as amended (“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. Repeal or modification of this RCRA exclusion or similar exemptions under state law could increase the amount of hazardous waste we

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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 addition, 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, as amended (“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 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all “other” fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the “other” wells must use reduced emission completions, also known as “green completions,” with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. We continually review new rules such as these to assess their impact on our operations. Compliance with new requirements could increase our costs of development and production, which costs could be significant.

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 an industry-wide effort 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 the granting of reasonable right-of-way access by land owners, investment from third parties in the development of gas gathering systems and processing facilities, and regulations, among other factors. However, we have allocated significant resources to connect our Bakken and Three Forks wells to natural gas infrastructure as quickly as possible in order to reduce our flared volumes. In addition, we have set a goal to maintain well connections for an average of 90% of our operated Bakken and Three Forks wells during the year ending December 31, 2014, and intend to report whether we have met this goal in our Annual Report on Form 10-K for such period. We believe that achieving this goal will help us to minimize our flared volumes of natural gas.

Climate change

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Based on findings made by the EPA in December 2009 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, 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 certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards, which will be established by the states or, in some instances, by the EPA on a case-by-case basis. 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, including, among others, certain oil and natural gas production facilities on an annual basis, 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 Congress has from time to time 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, such as electric power plants, 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. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and 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. 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, as amended (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 Oil Pollution Act of 1990, as amended ("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 production facilities that may affect waters of the United States. Under 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. North Dakota Industrial Commission 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. While we believe that we are in substantial compliance with applicable disposal well requirements, any changes in the

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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 conduct 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 gas commissions, but the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel fuels and published draft permitting guidance addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency continues to project issuance of a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time 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. 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. 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. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. 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 have been conducted or 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. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities in 2014. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and issued a report in 2011 on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale gas development. Also, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We have obtained an insurance policy that is intended to provide coverage for gradual pollution losses related to hydraulic fracturing operations. Additionally, we believe our general liability and excess liability insurance policies would generally cover third-party claims directly related to hydraulic fracturing operations conducted by third parties and associated legal expenses in accordance with, and subject to, the terms of such policies. However, certain long term pollution and environmental risks are not fully insurable. Please see "Item 1A. Risk Factors—We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks."

Endangered Species Act considerations

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The federal Endangered Species Act, as amended ("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. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. If endangered 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 September 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 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 Bureau of Land Management ("BLM") are subject to the National Environmental Policy Act, as amended ("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.

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, as amended ("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. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Employees

As of December 31, 2013, we employed 405 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, 2013, we leased 80,685 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 2017. We also own field offices in Williston, North Dakota, Powers Lake, North Dakota and Alexander, North Dakota.

Available information

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.

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Our common stock is listed and traded on the New York Stock Exchange 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, other than the documents listed below, 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

A substantial or extended decline 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. 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. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our 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 oil and natural gas reserves.” Lower 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 proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves” below.

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 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:

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- 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, 2013, 2012 and 2011.

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, 2013, 2012 and 2011, 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.

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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.

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. One example of emerging legal requirements is the midstream rules adopted by the North Dakota Industrial Commission in late December 2013 and expected to take effect in 2014 that impose more rigorous pipeline development standards relating to, among other things, pipe material selection and pipeline installation and backfilling techniques.

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 and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

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 $2,506.3 million (including acquisitions) and $1,148.6 million related to capital expenditures for the years ended December 31, 2013 and 2012, respectively. Our capital expenditure budget for 2014 is approximately $1,425 million, with approximately $1,250 million allocated for drilling and completion operations. Since our IPO, our capital expenditures have been financed with proceeds from our IPO, net cash provided by operating activities, proceeds from our $2,200.0 million of senior unsecured notes and proceeds from our secondary equity offering. DeGolyer and MacNaughton projects that we will incur capital costs (including abandonment obligations) in excess of $1,844 million over the next four years to develop the proved undeveloped reserves in the

Williston Basin covered by its December 31, 2013 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 and borrowings under our revolving credit facility; 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,

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thereby reducing our ability to use cash flows to fund working capital, capital 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 lower 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.

If oil and natural gas prices decrease, 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. 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. We may 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. No impairment on proved oil and natural gas properties was recorded for the years ended December 31, 2013, 2012 and 2011.

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.

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As of December 31, 2013, 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 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.

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. Although additional Williston Basin transportation takeaway capacity was added from 2011 to 2013, production also increased due to the elevated drilling activity in these years. The increased production coupled with delays in rail car arrivals and commissioning of rail loading facilities caused price differentials at times to be at the high-end of the historical average range of approximately 10% to 15% of the WTI crude oil index price in the first half of 2012. During the second half of 2012 and first half of 2013, differentials improved due to expanding rail infrastructure and pipeline expansions coming on line. During the second half of 2013, our price differentials again increased as the pipeline market weakened as a result of refinery down time and increased United States and Canadian production. 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.

Approximately 46% of our estimated net proved reserves were classified as proved undeveloped as of December 31, 2013. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. 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.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. 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.

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We have incurred losses in prior years and may do so again in the future.
For the years ended December 31, 2013, 2012 and 2011, we had net income of $228.0 million, $153.4 million and $79.4 million, respectively. However, prior to 2011, we incurred net losses. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures, including planned capital expenditures for 2014 of approximately $1,425 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 growth 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, 2013, we had leases representing 15,186 net acres expiring in 2014, 27,520 net acres expiring in 2015 and 14,719 net acres expiring in 2016. 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 year ended December 31, 2013, we recorded non-cash impairment charges of $1.2 million, and during each of the years ended December 31, 2012 and 2011, we

recorded non-cash impairment charges of $3.6 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 and comprehensive 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 or underground injection activities; the restriction of types, quantities and concentration of materials that can 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 operations. Numerous governmental authorities, such as the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; and the issuance of injunctions limiting or preventing some or all of our operations.

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 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 North Dakota Industrial Commission 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, and the state agency is also considering the designation of certain areas within the state as “extraordinary,” that, if adopted, may require exploration and production operators who seek to operate in such areas to file impact mitigation plans that would minimize disturbances to those areas. Additionally, new regulations could result in the issuance of less drilling permits or the issuance of permits at a slower rate, which could impact our overall drilling program. 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 “Other federal laws and regulations affecting our industry.”

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 in December 2009 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 certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or the EPA. 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, including, among others, certain onshore oil and natural gas production facilities on an annual basis, which includes certain of our operations. While Congress has from time to time 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, such as electric power plants, to acquire and

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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. 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 the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuels and published draft permitting guidance addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency continues to project issuance of a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time 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. 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 have been conducted or 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. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review in 2014. Moreover, the EPA has announced that it will develop effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities in 2014. The U.S. Department of Energy has conducted an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods and issued a report in 2011 on immediate and longer-term actions that may be taken to reduce environmental and safety risks of shale gas development. Also, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian oil and gas leases that would require public disclosure of chemicals used in hydraulic fracturing, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal Safe Drinking Water Act or other regulatory mechanisms.

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

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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.

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.

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.

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 United States 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.

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 growth and operating results.

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 will 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 subordinated debt;
- make investments;

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- 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 will be 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, 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.

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 80% 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, 2013, we had $335.6 million of outstanding borrowings and had $5.2 million of outstanding letters of credit under our revolving credit facility, $1,159.2 million available for future secured borrowings under our revolving credit facility 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. 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.

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 ($175.7 million in receivables at December 31, 2013), which we market to energy marketing companies, refineries and affiliates, and joint interest receivables ($139.5 million at December 31, 2013).

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 years ended December 31, 2013 and 2012, sales to Musket Corporation accounted for approximately 11% and 10% of our total sales, respectively. For the year ended December 31, 2011, sales to Texon L.P., Plains All American Pipeline, L.P. and Enserco Energy Inc. accounted for approximately 18%, 16% and 15%, respectively, of our total sales. No other purchasers accounted for more than 10% of our total oil and natural gas sales for the years ended December 31, 2013, 2012 and 2011. 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, 2013, we had derivatives in place with six counterparties and a total net derivative liability of $4.7 million.

We may be subject to risks in connection with acquisitions, including the West Williston Acquisition and the East Nesson 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 substantially all the assets we acquired in the West Williston Acquisition and the East Nesson Acquisitions as well as other producing properties that we acquire requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;

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- 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 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 the twelve-month 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 the West Williston Acquisition and the East Nesson 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, including the assets acquired in the West Williston Acquisition and the East Nesson Acquisitions, 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 the West Williston Acquisition, the East Nesson Acquisitions or another 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.

Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, 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.

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 growth 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, or in oil and natural gas industry conditions, or by risks and uncertainties relating to the exploratory prospects of the combined assets or operations, or 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 may be adversely affected.

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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.

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 2014 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;
- 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

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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. In addition, we are not aware of any material legal or governmental proceedings against us, or contemplated to be brought against us.

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 New York Stock Exchange ("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:

	2013		2012	
	High	Low	High	Low
1st Quarter	$39.78	$31.45	$35.46	$28.34
2nd Quarter	$42.89	$31.58	$33.90	$22.02
3rd Quarter	$49.48	$37.86	$32.72	$23.28
4th Quarter	$57.33	$42.70	$32.26	$28.15

Holders. The number of shareholders of record of our common stock was approximately 45,050 on February 21, 2014.

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 and growth 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 25, 2014, the last sale price of our common stock, as reported on the NYSE, was $43.44 per share.

Unregistered Sales of Securities. There were no sales of unregistered securities during the year ended December 31, 2013.

Issuer Purchases of Equity Securities. The following table contains information about our acquisition of equity securities during the three months ended December 31, 2013:

Period	Total Number of Shares Exchanged(1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number (or Approximate Dollar Value) of Shares that May Be Purchased Under the Plans or Programs
October 1 – October 31, 2013	2,245	$51.00	—	—
November 1 – November 30, 2013	285	51.68	—	—
December 1 – December 31, 2013	252	46.61	—	—
Total	2,782	$50.67	—	—

(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 of 1933, as amended, or Securities Exchange Act of 1934, as amended ("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 the Company's 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 IPO. The comparison was prepared based upon the following assumptions:

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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
2. Dividends are reinvested.

Item 6. Selected Financial Data

Set forth below is our summary historical consolidated financial data for the years ended December 31, 2013, 2012, 2011, 2010 and 2009, and balance sheet data at December 31, 2013, 2012, 2011, 2010 and 2009. 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,				
	2013[1]	2012	2011	2010	2009[2]
	(In thousands, except per share data)				
Statement of operations data:					
Revenues:					
Oil and gas revenues	$1,084,412	$670,491	$330,422	$128,927	$37,755
Well services and midstream revenues	57,587	16,177	—	—	—
Total revenues	1,141,999	686,668	330,422	128,927	37,755
Expenses:					
Lease operating expenses[3]	94,634	54,924	32,707	14,118	8,473
Well services and midstream operating expenses	30,713	11,774	—	—	—
Marketing, transportation and gathering expenses	25,924	9,257	1,365	464	218
Production taxes	100,537	62,965	33,865	13,768	3,810
Depreciation, depletion and amortization	307,055	206,734	74,981	37,832	16,670
Exploration expenses	2,260	3,250	1,685	297	1,019
Rig termination[4]	—	—	—	—	3,000
Impairment of oil and gas properties	1,168	3,581	3,610	11,967	6,233
Loss (gain) on sale of properties	—	—	207	—	(1,455)
Stock-based compensation expenses[5]	—	—	—	8,743	—
General and administrative expenses	75,310	57,190	29,435	19,745	9,342
Total expenses	637,601	409,675	177,855	106,934	47,310
Operating income (loss)	504,398	276,993	152,567	21,993	(9,555)
Other income (expense):					
Net gain (loss) on derivative instruments	(35,432)	34,164	1,595	(7,653)	(4,747)
Interest expense, net of capitalized interest	(107,165)	(70,143)	(29,618)	(1,357)	(912)
Other income (expense)	1,216	4,860	1,635	284	5
Total other income (expense)	(141,381)	(31,119)	(26,388)	(8,726)	(5,654)
Income (loss) before income taxes	363,017	245,874	126,179	13,267	(15,209)
Income tax expense[6]	135,058	92,486	46,789	42,962	—
Net income (loss)	$227,959	$153,388	$79,390	$(29,695)	$(15,209)
Earnings (loss) per share:					
Basic[7]	$2.45	$1.66	$0.86	$(0.31)	$—
Diluted[7]	2.44	1.66	0.86	(0.31)	—

(1) Our statement of operations data for the year ended December 31, 2013 does not include the effects of the East Nesson Acquisitions and West Williston Acquisition for the full twelve months of 2013. We acquired such interests on September 26, 2013 and October 1, 2013, respectively.

(2) Our statement of operations data for the year ended December 31, 2009 does not include the effects of the acquisition of interests in certain oil and gas properties from Kerogen Resources, Inc. and Fidelity Exploration and Production Company for the full twelve months of 2009. We acquired such interests on June 15, 2009 and September 30, 2009, respectively.

(3) For the years ended December 31, 2011, 2010 and 2009, lease operating expenses exclude marketing, transportation and gathering expenses to conform such amounts to current year classifications. For the years ended December 31, 2012, 2011, 2010 and 2009, 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 year ended December 31, 2013.

(4) During the first quarter of 2009, we paid a total of $3.0 million in rig termination expenses in connection with the early termination of two drilling rig contracts entered into in 2008.

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(5) During 2010, we recorded $8.7 million in stock-based compensation expense associated with Class C common unit interests and discretionary stock awards granted. Stock-based compensation expense related to the amortization of restricted stock and performance share units is included in general and administrative expenses on the Consolidated Statement of Operations.

(6) Prior to our corporate reorganization, we were a limited liability company not subject to entity-level taxation. Accordingly, no provision for federal or state corporate income taxes was recorded for the year ended December 31, 2009 as the taxable income was allocated directly to our equity holders. In connection with the closing of our IPO in June 2010, we merged into a corporation and became subject to federal and state entity-level taxation.

(7) Prior to our corporate reorganization in connection with our IPO, there was no common stock issued or outstanding and no earnings (loss) per share to disclose for the year ended December 31, 2009. Our loss per share for the year ended December 31, 2010 was restated and includes only the portion of net loss subsequent to our IPO and attributable to common stockholders.

	At December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Balance sheet data:					
Cash and cash equivalents	$91,901	$213,447	$470,872	$143,520	$40,562
Net property, plant and equipment	4,079,750	2,006,600	1,079,955	483,683	181,573
Total assets	4,711,924	2,528,794	1,727,382	691,852	239,553
Long-term debt	2,535,570	1,200,000	800,000	—	35,000
Total stockholders'/members' equity	1,348,549	795,005	634,238	551,794	171,850

	Year ended December 31,				
	2013	2012	2011	2010	2009
	(In thousands)				
Other financial data:					
Net cash provided by operating activities	$697,856	$392,386	$176,024	$49,612	$6,148
Net cash used in investing activities	(2,445,076)	(1,038,605)	(629,390)	(309,535)	(80,756)
Net cash provided by financing activities	1,625,674	388,794	780,718	362,881	113,600

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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 marketing business through OPM, a well services business through OWS, and a midstream services business through OMS, which are each complementary to our primary development and production activities. The businesses of OWS and OMS constitute separate reportable business segments. The revenues and expenses related to work performed by OPM, OWS and OMS for OPNA's working interests are eliminated in consolidation and, therefore, do not directly contribute to our consolidated results of operations.

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

We built our Williston Basin assets in our West Williston, East Nesson and Sanish project areas through acquisitions and development activities. These acquisitions and development activities 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 and proceeds from our public equity offerings.

Our 2013, 2012 and 2011 activities included development and exploration drilling in each of our primary project areas. Our current activities are focused on evaluating and developing our asset base, optimizing our acreage positions and evaluating potential acquisitions. Based on the reserve reports prepared by our independent reserve engineers, we had 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, 143.3 MMBoe of estimated net proved reserves with a PV-10 of $3,244.3 million and a Standardized Measure of $2,259.9 million at December 31, 2012 and 78.7 MMBoe of estimated net proved reserves with a PV-10 of $1,903.7 million and a Standardized Measure of $1,319.5 million at December 31, 2011. 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 $96.96/Bbl for oil and $3.66/MMBtu for natural gas, $94.68/Bbl for oil and $2.75/MMBtu for natural gas and $96.23/Bbl for oil and $4.12/MMBtu for natural gas for the years ended December 31, 2013, 2012 and 2011, 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.

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;

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- availability and cost of services; and
- availability of qualified personnel.

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

Prices for oil and natural gas can fluctuate widely in response to relatively minor changes in the global and regional supply of and demand for oil and natural gas, as well as market uncertainty, economic conditions and a variety of additional factors. Since the inception of our oil and natural gas activities, commodity prices have experienced significant fluctuations. We enter into crude oil sales contracts with purchasers who have access to crude oil transportation capacity, utilize derivative financial instruments to manage our commodity price risk and enter into physical delivery contracts to manage our price differentials. In an effort to improve price realizations from the sale of our oil and natural gas, we manage our commodities marketing activities in-house, which enables us to market and sell our oil and natural gas to a broader array of potential purchasers. Due to the availability of other markets and pipeline connections, we do not believe that the loss of any single oil or natural gas customer would have a material adverse effect on our results of operations or cash flows. Additionally, we sell a significant amount of our crude oil production through gathering systems connected to multiple pipeline and rail facilities. These gathering systems, which originate at the wellhead, reduce the need to transport barrels by truck from the wellhead. As of December 31, 2013, we were flowing approximately 75% 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.

	2013 Q1	Q2	Q3	Q4	Year ended December 31, 2013
Average Realized Oil Prices ($/Bbl)(1)	$93.33	$91.15	$100.75	$85.87	$92.34
Average Price Differential(2)	1 %	3 %	5 %	12 %	6 %
	2012 Q1	**Q2**	**Q3**	**Q4**	**Year ended December 31, 2012**
Average Realized Oil Prices ($/Bbl)(1)	$88.10	$82.36	$83.71	$86.82	$85.22
Average Price Differential(2)	14 %	12 %	9 %	2 %	9 %
	2011 Q1	**Q2**	**Q3**	**Q4**	**Year ended December 31, 2011**
Average Realized Oil Prices ($/Bbl)(1)	$82.33	$95.48	$83.52	$85.46	$86.18
Average Price Differential(2)	13 %	7 %	6 %	10 %	9 %

(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. Oil prices have increased significantly since 2009. The higher commodity prices, as well as continued successes in the application of completion technologies in the Bakken and Three Forks formations, caused the active drilling rig count in the Williston Basin to increase to approximately 192 rigs at December 31, 2013. Although additional Williston Basin transportation takeaway capacity was added in recent years, production also increased due to the elevated drilling activity. The increased production coupled with delays in rail car arrivals and commissioning of rail loading facilities caused price differentials at times to be at the high-end of the historical average range of approximately 10% to 15% of the WTI crude oil index price in the first half of 2012. In the third quarter of 2012, our average price differentials relative to WTI began to narrow, primarily due to transportation capacity additions, including expanded rail infrastructure and pipeline expansions, outpacing production growth. In the fourth quarter of 2012 and into the first quarter of 2013, average price differentials continued to narrow, primarily due to our ability to access premium coastal markets by rail. As the premium 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, 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 United States and Canadian production. 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.

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Our large concentrated acreage position potentially provides us with a multi-year inventory of drilling projects and requires some forward planning visibility for obtaining services. Our ability to develop and hold our existing undeveloped leasehold acreage is primarily dependent upon having access to drilling rigs and completion services. To ensure access to drilling rigs, we have entered into fixed-term drilling rig contracts for periods of up to three years and currently have 14 drilling rigs under contract. In order to ensure the availability of completion services and the timely fracture stimulation of newly drilled wells, we formed OWS in 2011 to provide well services on our operated wells, in addition to entering into fracturing service contracts with third party companies. We are also adding a second fracturing fleet to OWS in 2014 to further ensure our ability to complete our wells.

2013 Highlights

- We completed and placed on production 136 gross (106.1 net) operated Bakken and Three Forks wells during 2013, and increased average daily production by 51% to 33,904 Boe per day from 22,469 Boe per day in 2012.
- We increased estimated net proved oil and natural gas reserves at December 31, 2013 to 227.9 MMBoe, a 59% increase over year-end 2012 estimated net proved reserves. Approximately 87% of our estimated net proved reserves at year-end 2013 consisted of oil and 54% were classified as proved developed.
- We grew our leasehold position to 515,314 total net acres in the Williston Basin, primarily targeting the Bakken and Three Forks formations, and increased our operated drilling spacing units by 123 through acquisitions, acreage additions and trades during 2013. In addition, we increased our acreage that is held-by-production to 422,386 net acres as of December 31, 2013.
- During 2013, we closed four separate purchase and sale agreements to acquire an aggregate of approximately 161,000 net acres in the Williston Basin.
- In the first quarter of 2013, our salt water disposal assets were transferred from OPNA to the newly formed OMS, which provides midstream services to OPNA’s operated wells.
- On September 24, 2013, we issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022. The issuance of these notes resulted in net proceeds to us of approximately $983.6 million, which we used to fund the West Williston Acquisition.
- On December 9, 2013, we completed a public offering of 7,000,000 shares of our common stock, par value $0.01 per share, at an offering price of $44.94 per share. Net proceeds from the offering were approximately $314.4 million.
- As of December 31, 2013, we had 14 operated rigs running.
- At December 31, 2013, we had $91.9 million of cash and cash equivalents and had total liquidity of $1,251.1 million, including our $1,500.0 revolving credit facility.
- Our total 2014 capital expenditure budget is $1,425 million, which includes $1,367 million for E&P capital expenditures and $58 million for non-E&P capital expenditures. Our planned capital expenditures primarily consist of:

$1,250 million of drilling and completion (including production-related equipment) capital expenditures for operated and non-operated wells (including expected savings from services provided by OWS and OMS);

$60 million for constructing infrastructure to support production in our core project areas, primarily related to salt water disposal systems;

$25 million for maintaining and expanding our leasehold position;

$19 million for field facilities and other miscellaneous E&P capital expenditures;

$13 million for collection of subsurface reservoir data;

$35 million for OWS, including district tools; and

$23 million for other non-E&P capital, including items such as administrative capital and capitalized interest.

Results of Operations

Revenues

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

from well completion activity and salt water disposal for third-party working interest owners in OPNA’s operated wells.
The following table summarizes our revenues and production data for the periods presented:

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	Year ended December 31,		
	2013	2012	2011
Operating results (in thousands):			
Revenues			
Oil	$1,033,866	$643,446	$321,668
Natural gas	50,546	27,045	8,754
Well services and midstream	57,587	16,177	—
Total revenues	$1,141,999	$686,668	$330,422
Production data:			
Oil (MBbls)	11,133	7,533	3,732
Natural gas (MMcf)	7,450	4,146	1,092
Oil equivalents (MBoe)	12,375	8,224	3,914
Average daily production (Boe/d)	33,904	22,469	10,724
Average sales prices:			
Oil, without derivative settlements (per Bbl)(1)	$92.34	$85.22	$86.18
Oil, with derivative settlements (per Bbl)(1)(2)	91.61	86.09	85.15
Natural gas (per Mcf)(3)	6.78	6.52	8.02

(1) For the years ended December 31, 2013 and 2012, average sales prices for oil are calculated using total oil revenues, excluding bulk oil sales of $5.8 million and $1.5 million, respectively, 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.

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

Year ended December 31, 2013 as compared to year ended December 31, 2012

Total revenues. Our total revenues increased $455.3 million, or 66%, to $1,142.0 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012. Our primary revenues are a function of oil and natural gas production volumes sold and average sales prices received for those volumes. Average daily production sold increased by 11,435 Boe per day, or 51%, to 33,904 Boe per day during the year ended December 31, 2013 as compared to the year ended December 31, 2012. The increase in average daily production sold was primarily a result of a higher number of well completions during 2013 coupled with our West Williston Acquisition and East Nesson Acquisitions and offset by the decline in production in wells that were producing as of December 31, 2012. Production from wells completed in our West Williston, East Nesson and Sanish project areas contributed to average daily production during 2013 by approximately 7,119 Boe per day, 4,117 Boe per day and 706 Boe per day, respectively. Average oil sales prices, without derivative settlements, increased by $7.12/Bbl, or 8%, to an average of $92.34/Bbl for the year ended December 31, 2013 as compared to the year ended December 31, 2012. The higher production amounts sold increased revenues by $354.9 million, and higher oil and natural gas sales prices increased revenues by $54.7 million during the year ended December 31, 2013. In addition, bulk oil sales related to marketing activities included in oil revenues increased $4.3 million during the year ended December 31, 2013 as compared to the year ended December 31, 2012.

Well services revenues increased $35.7 million for the year ended December 31, 2013 compared to the year ended December 31, 2012 due to an increase in well completion activity and related product sales and tool rentals. Midstream revenues totaled $5.7 million for the year ended December 31, 2013. There were no midstream revenues during 2012 because OMS did not commence activity until the first quarter of 2013. Prior to 2013, our salt water disposal systems were owned by OPNA, and the related income was included as a reduction to lease operating expenses. Well services and midstream revenues represent revenue for third-party working interest owners in OPNA's operated wells only, as work performed by OWS and OMS for OPNA's working interests are eliminated in consolidation.

Year ended December 31, 2012 as compared to year ended December 31, 2011

Total revenues. Our total revenues increased $356.2 million, or 108%, to $686.7 million during the year ended December 31, 2012 as compared to the year ended December 31, 2011. Our exploration and production 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 11,745 Boe per day, or 110%, to 22,469 Boe per day during the year ended December 31, 2012 as compared to the

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year ended December 31, 2011. The increase in average daily production sold was primarily a result of a higher number of well completions during 2012, offsetting the decline in production in wells that were producing as of December 31, 2011. Production from wells completed in our West Williston, East Nesson and Sanish project areas contributed to average daily production by approximately 8,085 Boe per day, 2,514 Boe per day and 819 Boe per day, respectively, during 2012. Average oil sales prices, without derivative settlements, decreased by $0.96/Bbl, or 1%, to an average of $85.22/Bbl for the year ended December 31, 2012 as compared to the year ended December 31, 2011. The higher production amounts sold increased revenues by $343.7 million, while lower oil and natural gas sales prices decreased revenues by $5.2 million. Well services revenues were $16.2 million for the year ended December 31, 2012. There were no well services revenues during the year ended December 31, 2011 because OWS did not commence fracturing activity until the first quarter of 2012. The remaining $1.5 million increase in total revenues was attributable to oil bulk purchase revenues related to marketing activities included in oil revenues during the year ended December 31, 2012.

Expenses

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

	Year ended December 31,		
	2013	2012	2011
	(In thousands, except per Boe of production)		
Expenses:			
Lease operating expenses[(1)]	$94,634	$54,924	$32,707
Well services and midstream operating expenses	30,713	11,774	—
Marketing, transportation and gathering expenses	25,924	9,257	1,365
Production taxes	100,537	62,965	33,865
Depreciation, depletion and amortization	307,055	206,734	74,981
Exploration expenses	2,260	3,250	1,685
Impairment of oil and gas properties	1,168	3,581	3,610
Loss on sale of properties	—	—	207
General and administrative expenses	75,310	57,190	29,435
Total expenses	637,601	409,675	177,855
Operating income	504,398	276,993	152,567
Other income (expense):			
Net gain (loss) on derivative instruments	(35,432)	34,164	1,595
Interest expense, net of capitalized interest	(107,165)	(70,143)	(29,618)
Other income (expense)	1,216	4,860	1,635
Total other income (expense)	(141,381)	(31,119)	(26,388)
Income before income taxes	363,017	245,874	126,179
Income tax expense	135,058	92,486	46,789
Net income	$227,959	$153,388	$79,390
Costs and expenses (per Boe of production):			
Lease operating expenses[(1)]	$7.65	$6.68	$8.36
Marketing, transportation and gathering expenses	2.09	1.13	0.34
Production taxes	8.12	7.66	8.65
Depreciation, depletion and amortization	24.81	25.14	19.16
General and administrative expenses	6.09	6.95	7.52

(1) 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 year

ended December 31, 2013.

Year ended December 31, 2013 compared to year ended December 31, 2012

Lease operating expenses. Lease operating expenses increased $39.7 million to $94.6 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. This increase was primarily due to the costs associated with operating an increased number of producing wells and associated produced fluid volumes as a result of our 2013 well completions and acquisitions. Increased costs primarily related to workovers, chemical treatments, diesel, equipment rental and repairs, which have improved operational performance and minimized downtime in our wells. Additionally, the formation of OMS in the first quarter of 2013 resulted in income related to midstream activity being included in well services and midstream revenues, rather than as a reduction to lease operating expenses. Lease operating expenses increased from $6.68 for the year ended December 31, 2012 to $7.65 for the year ended December 31, 2013. This increase in unit operating costs was primarily due to the effect of the formation of OMS coupled with higher costs on wells we acquired in the West Williston Acquisition and the East Nesson Acquisitions.

Well services and midstream operating expenses. Well services and midstream operating expenses represent third-party working interest owners' share of completion service costs and cost of goods sold incurred by OWS and midstream operating expenses incurred by OMS. The $18.9 million increase for the year ended December 31, 2013 compared to the year ended December 31, 2012 was attributable to a $17.4 million increase from OWS' well completion activity and related product sales, and a $1.5 million increase related to midstream operating expenses. There were no midstream operating expenses for the year ended December 31, 2012 because OMS did not commence activity until the first quarter of 2013.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses includes all of our marketing, transportation and gathering charges for our oil production as well as bulk oil purchase costs. The $16.7 million increase year over year, or $0.96 increase per Boe, is primarily attributable to increased oil transportation costs associated with having additional wells connected to third-party infrastructure, combined with a $4.4 million increase in costs related to bulk oil purchases made by OPM and a $2.1 million increase due to the change in the non-cash valuation adjustments on our oil pipeline imbalances and linefill inventory. Excluding these non-cash valuation adjustments and bulk oil purchase costs, our marketing, transportation and gathering expenses on a per Boe basis would have been $1.52 and $1.04 for the years ended December 31, 2013 and 2012, respectively.

Production taxes. Our production taxes for the years ended December 31, 2013 and 2012 were 9.3% and 9.4%, respectively, as a percentage of oil and natural gas sales, and are inclusive of lower incentivized production tax rates on certain new Montana wells. For each of the years ended December 31, 2013 and 2012, approximately 82% of our production was in North Dakota with an average production tax rate of approximately 11%.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $100.3 million to $307.1 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. The increase in DD&A expense for the year ended December 31, 2013 was primarily a result of our production increases from our wells completed during 2013. The DD&A rate for the year ended December 31, 2013 was $24.81 per Boe compared to $25.14 per Boe for the year ended December 31, 2012. The decrease in DD&A rate was a result of lower well costs for wells completed during the second half of 2012 and the first half of 2013, partially offset by costs related to the West Williston Acquisition. Our lower well costs were a result of decreases in service costs in the Williston Basin, efficiency gains, completion and well design optimization and pad development operations. The West Williston Acquisition completed on October 1, 2013 increased our DD&A rate by approximately $1.90 per Boe for the fourth quarter of 2013.

Impairment of oil and gas properties. No impairment of proved oil and natural gas properties was recorded for the years ended December 31, 2013 and 2012. During the years ended December 31, 2013 and 2012, we recorded non-cash impairment charges of $1.2 million and $3.6 million, respectively, for unproved properties due to leases that expired during the period and periodic assessments of unproved properties. The 2012 impairment charge included $1.8 million related to acreage expiring in 2013 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. Our general and administrative expenses increased $18.1 million for the year ended December 31, 2013 from $57.2 million for the year ended December 31, 2012. Of this increase, approximately $15.1 million was due to the impact of our organizational growth on employee compensation and $1.6 million was due to increased amortization of our restricted stock awards and performance share units ("PSUs") year over year. As of December 31, 2013, we had 405 full-time employees compared to 281 full-time employees as of December 31, 2012. In addition, $2.0 million was included in general and administrative expenses for costs related to our acquisitions during the year ended December 31, 2013.

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Derivatives. As a result of our derivative activities, we incurred an $8.1 million net cash settlement loss for the year ended December 31, 2013 and a $6.5 million net cash settlement gain for the year ended December 31, 2012. In addition, as a result of forward oil price changes, we recognized a $27.3 million non-cash mark-to-market derivative loss during the year ended December 31, 2013 and a $27.6 million non-cash mark-to-market derivative gain during the year ended December 31, 2012.

Interest expense. Interest expense increased $37.0 million to $107.2 million for the year ended December 31, 2013 compared to the year ended December 31, 2012. The increase was primarily due to the interest related to our senior unsecured notes issued in July 2012 and September 2013, both issued at an interest rate of 6.875%, coupled with interest expense incurred on borrowings under our revolving credit facility during 2013. 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%. There were no borrowings under our revolving credit facility during the year ended December 31, 2012. We capitalized $4.6 million and $3.3 million of interest costs for the years ended December 31, 2013 and 2012, respectively, which will be amortized over the life of the related assets.

Income tax expense. Income tax expense for the years ended December 31, 2013 and 2012 was recorded at 37.2% and 37.6% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the United States and the blended state rate of the states in which we conduct business.

Year ended December 31, 2012 compared to year ended December 31, 2011

Lease operating expenses. Lease operating expenses increased $22.2 million to $54.9 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. 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 2012 well completions. Increased costs primarily related to workovers, chemical treatments, equipment rental and fresh water injections, which have improved operational performance and minimized downtime in our wells. These cost increases were partially offset by salt water disposal activity and lower operating costs related to improved weather conditions as compared to the first half of 2011. The unit operating costs decreased from $8.36 for the year ended December 31, 2011 to $6.68 for the year ended December 31, 2012, primarily due to our increase in production of 110% outpacing our overall net increase in costs of 68%.

Well services operating expenses. The $11.8 million in well services operating expenses represents third-party working interests' share of fracturing service costs incurred by OWS for fracturing jobs completed in 2012. There were no well services operating expenses in 2011 because OWS did not commence fracturing activity until the first quarter of 2012.

Marketing, transportation and gathering expenses. Marketing, transportation and gathering expenses includes all of our marketing, transportation and gathering for our oil production as well as bulk oil purchase costs. The $7.9 million increase period over period, or $0.79 increase per Boe, is primarily attributable to increased oil transportation costs related to OPM, which did not commence operations until late in the third quarter of 2011, combined with a $1.4 million cost for bulk oil purchases made by OPM in the first quarter of 2012, partially offset by a $0.7 million non-cash valuation adjustment on our oil pipeline imbalances. Excluding this pipeline imbalance adjustment and bulk oil purchase costs, our marketing, transportation and gathering expenses on a per Boe basis would have been $1.04 for the year ended December 31, 2012.

Production taxes. Our production taxes for the years ended December 31, 2012 and 2011 were 9.4% and 10.2%, respectively, as a percentage of oil and natural gas sales. The 2012 production tax rate was lower than the 2011 production tax rate because of the increased weighting of oil revenues in Montana, which has lower incentivized production tax rates on certain new wells. For the years ended December 31, 2012 and 2011, the percentage of our total production that was in North Dakota was 82% and 85%, respectively, with an average production tax rate of approximately 11%.

Depreciation, depletion and amortization (DD&A). DD&A expense increased $131.8 million to $206.7 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. The increase in DD&A expense for the year ended December 31, 2012 was primarily a result of our production increases from our 2012 well completions. The DD&A rate for the year ended December 31, 2012 was $25.14 per Boe compared to $19.16 per Boe for the year ended December 31, 2011. The higher DD&A rate was a result of increased well costs in 2012, which outpaced the increase in associated reserves. The increased well costs were a result of increases in service costs in the Williston Basin during 2011 and the first half of 2012 and the addition of infrastructure assets, primarily our salt water disposal systems.

Impairment of oil and gas properties. No impairment of proved oil and natural gas properties was recorded for the years ended December 31, 2012 and 2011. During the years ended December 31, 2012 and 2011, we recorded non-cash impairment charges of $3.6 million each year for unproved properties due to leases that expired during the period and periodic assessments of unproved properties. The 2012 impairment charge included $1.8 million related to acreage expiring in 2013 as a result of a periodic assessment 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

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accounting policies and estimates—Impairment of proved properties" and "Critical accounting policies and estimates—Impairment of unproved properties."

General and administrative. Our general and administrative expenses increased $27.8 million for the year ended December 31, 2012 from $29.4 million for the year ended December 31, 2011. Of this increase, approximately $20.3 million was due to the impact of our organizational growth on employee compensation and $6.7 million was due to the amortization of our restricted stock awards and PSUs. As of December 31, 2012, we had 281 full-time employees compared to 146 full-time employees as of December 31, 2011.

Derivatives. As a result of our derivative activities, we incurred a $6.5 million net cash settlement gain for the year ended December 31, 2012 and a $3.8 million net cash settlement loss for the year ended December 31, 2011. In addition, as a result of forward oil price changes, we recognized non-cash mark-to-market derivative gains of $27.6 million and $5.4 million during the years ended December 31, 2012 and 2011, respectively.

Interest expense. Interest expense increased $40.5 million to $70.1 million for the year ended December 31, 2012 compared to the year ended December 31, 2011. The increase was due to the interest related to our senior unsecured notes issued in February and November 2011 and July 2012. For the years ended December 31, 2012 and 2011, we incurred no borrowings under our revolving credit facility. We capitalized $3.3 million and $3.1 million of interest costs for the years ended December 31, 2012 and 2011, respectively, which will be amortized over the life of the related assets.

Income tax expense. Income tax expense for the years ended December 31, 2012 and 2011 was recorded at 37.6% and 37.1% of pre-tax net income, respectively. Our effective tax rate is expected to continue to closely approximate the statutory rate applicable to the United States 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 and cash flows from operations. Our primary use of capital has been for the development and acquisition of oil and natural gas properties. We continually monitor potential capital sources, including equity and debt financings, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital.

Our cash flows for the years ended December 31, 2013, 2012 and 2011 are presented below:

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
Net cash provided by operating activities	$697,856	$392,386	$176,024
Net cash used in investing activities	(2,445,076)	(1,038,605)	(629,390)
Net cash provided by financing activities	1,625,674	388,794	780,718
Net change in cash	$(121,546)	$(257,425)	$327,352

Our cash flows depend on many factors, including the price of oil and natural gas and the success of our development and exploration activities as well as future acquisitions. We actively manage our exposure to commodity price fluctuations by executing derivative transactions to mitigate the change in oil prices on a portion of our production, thereby mitigating our exposure to oil price declines, but these transactions may also limit our cash flow in periods of rising oil prices. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Cash flows provided by operating activities

Net cash provided by operating activities was $697.9 million, $392.4 million and $176.0 million for the years ended December 31, 2013, 2012 and 2011, respectively. The increase in cash flows provided by operating activities for the year ended December 31, 2013 as compared to 2012 was primarily the result of our 50% increase in oil and natural gas production year over year. The increase in cash flows provided by operating activities for the year ended December 31, 2012 as compared to 2011 was primarily the result of an increase in oil and natural gas production of 110%.

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Working capital. Our working capital fluctuates primarily as a result of changes in commodity pricing and production volumes, capital spending to fund our exploratory and development initiatives and acquisitions and the impact of our outstanding derivative instruments. We had a working capital deficit of $18.8 million at December 31, 2013. We believe we have adequate liquidity to meet our working capital requirements. As of December 31, 2013, we had $1,251.1 million of liquidity available, including $91.9 million in cash and cash equivalents and $1,159.2 million available under our revolving credit facility. At December 31, 2012, we had a working capital surplus of $161.9 million. This surplus was primarily attributable to our cash and cash equivalents balance of $213.4 million at December 31, 2012 as a result of the proceeds from the issuance of our senior unsecured notes in July 2012.

Cash flows used in investing activities

We had cash flows used in investing activities of $2,445.1 million, $1,038.6 million and $629.4 million during the years ended December 31, 2013, 2012 and 2011, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. The increase in cash used in investing activities for the year ended December 31, 2013 compared to 2012 of $1,406.5 million was a result of $1,560.1 million for acquisitions in 2013 primarily related to the West Williston Acquisition and the East Nesson Acquisitions, offset by a decrease in expenditures for the development of our properties. The increase in cash used in investing activities for the year ended December 31, 2012 compared to 2011 of $409.2 million was attributable to increased levels of expenditures 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 drilling, development and acquisition costs for the years ended December 31, 2013, 2012 and 2011 are summarized in the following table:

	Year ended December 31,		
	2013	2012	2011
	(In thousands)		
E&P capital expenditures by project area:			
West Williston	$497,620	$725,873	$499,558
East Nesson	378,541	322,946	110,013
Sanish	40,568	62,879	27,436
Other(1)	—	—	282
Acquisitions	1,563,411	—	—
Total E&P capital expenditures(2)	2,480,140	1,111,698	637,289
Oasis Well Services (OWS)	15,217	15,679	—
Non-E&P capital expenditures(3)	10,941	21,196	28,685
Total capital expenditures(4)	$2,506,298	$1,148,573	$665,974

(1) Other capital expenditures represent data relating to our properties in the Barnett shale, which we sold in November 2011.

(2) Total E&P capital expenditures include $19.0 million for OMS, primarily related to pipelines and salt water disposal wells.

(3) Non-E&P capital expenditures include such items as administrative capital and capitalized interest.

(4) 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 addition, acquisitions reflected in the table include inventory purchased as part of our acquisitions, which is included in net cash provided by operating activities in the statement of cash flows in our consolidated financial statements.

In 2013, we spent $2,506.3 million on capital expenditures, which represented a 118% increase over the $1,148.6 million spent during 2012. Excluding the West Williston Acquisition and the East Nesson Acquisitions in

2013 totaling $1,551.7 million, we spent $954.6 million, which represented a 17% decrease compared to 2012. The reduction in capital expenditures, excluding the impact of the acquisitions, was primarily due to lower well capital costs partially offset by more drilling and completion activity.

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During 2013, we participated in 250 gross wells (115.1 net) that were completed and placed on production, and, as operator, we completed and placed on production 136 gross (106.1 net) of these wells. In addition, as of December 31, 2013, we had 41 gross operated wells awaiting completion and 18 gross operated wells in the process of drilling in the Bakken and Three Forks formations. Our land leasing and acquisition activity is focused in and around our existing core consolidated land positions, primarily in our West Williston project area.

We anticipate investing $1,367 million for drilling, development and acquisition costs in 2014 as follows:

	(In thousands)
Drilling and completing wells (including production-related equipment)	$1,250,000
Constructing infrastructure to support production in our core project areas	60,000
Maintaining and expanding our leasehold position	25,000
Field facilities and other E&P capital expenditures	19,000
Collection of subsurface reservoir data	13,000
Total E&P capital expenditures	1,367,000
Non-E&P capital expenditures	58,000
Total capital expenditures	$1,425,000

While we have budgeted a total of $1,425 million for total capital expenditures in 2014, 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, as was the case in 2013, our capital expenditures may be higher than budgeted. We believe that cash on hand, cash flows from operating activities and availability under our revolving credit facility should be more than sufficient to fund our 2014 capital expenditure budget. However, because the operated wells funded by our 2014 drilling plan represent only a small percentage of our gross potential drilling locations, we will be required to generate or raise multiples of this amount of capital to develop our entire inventory of potential drilling locations should we elect to do so.

Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control. 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 $1,625.7 million, $388.8 million and $780.7 million for the years ended December 31, 2013, 2012 and 2011, respectively. For the year ended December 31, 2013, cash sourced through financing activities was primarily provided by net proceeds from the issuance of our common stock, the issuance of our senior unsecured notes and borrowings under our revolving credit facility. For the years ended December 31, 2012 and 2011, cash sourced through financing activities was primarily provided by net proceeds from the issuance of our senior unsecured notes.

Sale of common stock. On December 9, 2013, we completed a public offering of 7,000,000 shares of common stock, par value $0.01 per share, at an offering price of $44.94 per share. We received net proceeds from the offering of $314.4 million, after deducting underwriting discounts and estimated offering expenses. We used a portion of these net proceeds to repay $264.4 million of outstanding indebtedness under our revolving credit facility, and the remaining proceeds were used for general corporate purposes.

Senior unsecured notes. On September 24, 2013, we issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”). Interest is payable on the 2022 Notes semi-annually in arrears on each March 15 and September 15, commencing March 15, 2014. The 2022 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2022 Notes resulted in net proceeds to us of approximately $983.6 million, which we used to fund a portion of the $1,478.6 million purchase price of the West Williston Acquisition (see Note 6 to our audited Consolidated Financial Statements for a description of our acquisitions).

At any time prior to September 15, 2016, we may redeem up to 35% of the 2022 Notes at a redemption price of 106.875% of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings as long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the 2022 Notes remains outstanding after such redemption. Prior to September 15, 2017, we may redeem some or all of the 2022 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after September 15, 2017, we may redeem some or all of the 2022 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.438% for the twelve-month period beginning on September 15, 2017, 101.719% for the twelve-month period beginning on September 15, 2018 and 100.00% beginning on September 15, 2019, plus accrued and unpaid interest to the redemption date.

In connection with the issuance of the 2022 Notes, we, along with certain of our subsidiaries, entered into a registration rights agreement pursuant to which we agreed to file a registration statement with the SEC to allow the holders of the 2022 Notes to exchange the 2022 Notes for the same principal amount of a new issue of notes with substantially identical terms, except the new notes will be freely transferable under the Securities Act. We will use commercially reasonable efforts to cause the exchange to be completed within 360 days after the 2022 Notes issuance date. Under certain circumstances, in lieu of a registered exchange offer, we must use commercially reasonable efforts to file a shelf registration statement for the resale of the 2022 Notes. If we fail to satisfy these obligations on a timely basis, the annual interest borne by the 2022 Notes will be increased by 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective. We estimate the value of this contingent interest is immaterial at December 31, 2013.

On July 2, 2012, we issued $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes”). Interest is payable on the 2023 Notes semi-annually in arrears on each January 15 and July 15, commencing January 15, 2013. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2023 Notes resulted in net proceeds to us of approximately $392.4 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

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

On November 10, 2011, we issued $400.0 million of 6.5% senior unsecured notes due November 1, 2021 (the “2021 Notes”). Interest is payable on the 2021 Notes semi-annually in arrears on each May 1 and November 1, commencing May 1, 2012. The 2021 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2021 Notes resulted in net proceeds to us of approximately $393.4 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

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

November 1, 2018 and 100.00% beginning on November 1, 2019, plus accrued and unpaid interest to the redemption date.

On February 2, 2011, we issued $400.0 million of 7.25% senior unsecured notes due February 1, 2019 (the “2019 Notes”). Interest is payable on the 2019 Notes semi-annually in arrears on each February 1 and August 1, commencing August 1, 2011. The 2019 Notes are guaranteed on a senior unsecured basis by our material subsidiaries. The issuance of these 2019 Notes resulted in net proceeds to us of approximately $390.0 million, which we used to fund our exploration, development and acquisition program and for general corporate purposes.

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Prior to February 1, 2015, we may redeem some or all of the 2019 Notes for cash at a redemption price equal to 100% of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. On and after February 1, 2015, we may redeem some or all of the 2019 Notes at redemption prices (expressed as percentages of the principal amount) equal to 103.625% for the twelve-month period beginning on February 1, 2015, 101.813% for the twelve-month period beginning on February 1, 2016 and 100.00% beginning on February 1, 2017, plus accrued and unpaid interest to the redemption date.

The indentures governing our 2019 Notes, 2021 Notes, 2022 Notes and 2023 Notes (collectively, the "Notes") restrict our ability and the ability of certain of our subsidiaries to: (i) incur additional debt or enter into sale and leaseback transactions; (ii) pay distributions on, redeem or repurchase equity interests; (iii) make certain investments; (iv) incur liens; (v) enter into transactions with affiliates; (vi) merge or consolidate with another company; and (vii) transfer and sell assets. These covenants are subject to a number of important exceptions and qualifications. If at any time when our Notes are rated investment grade by both Moody's Investors Service, Inc. and Standard & Poor's Ratings Services and no default (as defined in the indentures) has occurred and is continuing, many of such covenants will terminate and we will cease to be subject to such covenants.

Senior secured revolving line of credit. On April 5, 2013, OP LLC, as parent, and OPNA, as borrower, entered into the Second Amended Credit Facility, which has a maturity date of April 5, 2018. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. Borrowings under our Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of our assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports. In connection with entry into the Second Amended Credit Facility, the semi-annual redetermination of our borrowing base was also completed on April 5, 2013, which resulted in an increase to the borrowing base of the Second Amended Credit Facility from $750.0 million to $1,250.0 million. However, we elected to limit the aggregate commitment of the lenders under the Second Amended Credit Facility (the "Lenders") to $900.0 million. In addition, under the Second Amended Credit Facility, the overall credit facility increased from $1,000.0 million to $2,500.0 million.

On September 3, 2013, we entered into an amendment to our Second Amended Credit Facility (the "Amendment"). In connection with the Amendment, the Lenders under our Second Amended Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for October 1, 2013. Following the redetermination, our borrowing base increased from $1,250.0 million to $1,500.0 million and elected commitments also totaled $1,500.0 million.

On a quarterly basis, we pay a 0.375% (as of December 31, 2013) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

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 (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.

As of December 31, 2013, we had $335.6 million of borrowings and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base capacity of $1,159.2 million. As of December 31, 2013, the weighted average interest rate on borrowings under the Second Amended Credit Facility was 1.8%. For the year

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ended December 31, 2013, the weighted average debt outstanding under the Second Amended Credit Facility was $143.0 million and the weighted average interest rate incurred on the outstanding borrowings was 2.0%. As of December 31, 2012, we had no borrowings and $2.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused elected commitments capacity of $497.8 million. We were in compliance with the financial covenants of the Second Amended Credit Facility as of December 31, 2013 and 2012.

Obligations and commitments

We have the following contractual obligations and commitments as of December 31, 2013 (in thousands):

	Payments due by period				
Contractual obligations	Total	Within 1 year	1-3 years	3-5 years	More than 5 years
Operating leases(1)	$11,111	$2,927	$5,949	$2,235	$—
Drilling rig commitments(1)	26,227	24,365	1,862	—	—
Volume commitment agreements(1)	49,280	10,229	21,609	17,442	—
Purchase agreements(1)	4,968	994	1,987	1,987	—
Cost sharing agreements(1)	12,741	5,683	7,058	—	—
Investment commitment(1)	7,049	—	7,049	—	—
Senior unsecured notes(2)	2,200,000	—	—	—	2,200,000
Interest payments on senior unsecured notes(2)	1,211,406	149,531	302,500	302,500	456,875
Borrowings under revolving credit facility(2)	335,570	—	—	335,570	—
Interest payments on borrowings under revolving credit facility(2)	1,329	1,329	—	—	—
Asset retirement obligations(3)	36,458	540	2,037	1,009	32,872
Total contractual cash obligations	$3,896,139	$195,598	$350,051	$660,743	$2,689,747

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

(2) 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, 2013, we had $335.6 million of borrowings and $5.2 million of outstanding letters of credit issued under our Second Amended Credit Facility.

(3) Amounts represent our estimate of future asset retirement obligations on an undiscounted basis. 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.

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 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 depreciation, depletion and amortization ("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 services have been performed or related products have been delivered. OWS provides wells services and sells related products primarily to OPNA. Midstream revenues consist of revenues from salt water disposal 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.

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 have historically recognized 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 additional project-specific risking factors. In addition, when appropriate, we review comparable purchases and sales of oil and

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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.

Capitalized interest

We capitalize a portion of our interest expense incurred on our outstanding debt. The amount capitalized is determined by multiplying the capitalization rate by the average amount of eligible accumulated capital expenditures and is limited to actual interest costs incurred during the period. The accumulated capital expenditures included in the capitalized interest calculation begin when the first costs are incurred and end when the asset is either placed into production or written off. Amounts capitalized are amortized over the life of the related assets.

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 asset retirement obligation ("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. 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. 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. Cash settlements of commodity derivative instruments and gains and losses from valuation changes in the remaining unsettled 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 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 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. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the stock-based compensation expense recognized (see Note 12 to our audited Consolidated Financial Statements for a description of these inputs). Stock-based compensation expense recorded for PSUs is included in general and administrative expenses on our Consolidated Statement of Operations.

Treasury stock

Treasury stock shares represent shares withheld by us equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards. We include the withheld shares as treasury stock on our Consolidated Balance Sheet and separately pay the payroll tax obligation. These retained shares are not part of a publicly announced program to repurchase shares of our common stock and are accounted for at cost. We do not have a publicly announced program to repurchase shares of our common stock.

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.

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, 2013, 2012 and 2011. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our areas of operations.

Off-balance sheet arrangements

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

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

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

cover a significant portion of our future production.
We utilize derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2013, we utilized two-way and three-way costless collar options, put spreads, swaps and swaps with sub-floors to reduce the volatility of oil prices on a significant portion of our future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price

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(ceiling) we will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be WTI plus the difference between the purchased put and the sold put strike price. The sold call establishes a maximum price (ceiling) we will receive for the volumes under contract. A put spread is a combination of a purchased put and a sold put, and in this case does not include a sold call, allowing the volumes under this contract to have no established maximum price (ceiling). A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A swap with a sub-floor is a swap coupled with a sold put (sub-floor) at which point the minimum price would be WTI crude oil index price plus the difference between the swap and the sold put strike price.
We recognize all derivative instruments at fair value. The credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet. Derivative assets and liabilities arising from our derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement.
The following is a summary of our derivative contracts as of December 31, 2013:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices				Fair Value Asset (Liability)
			Swap	Sub-Floor	Floor	Ceiling	
		(Barrels)	($/Barrel)				(In thousands)
2014	Two-way collars	1,510,000			$90.77	$102.06	$302
2014	Three-way collars	3,530,530		$70.30	$90.65	$105.64	2,927
2014	Put spreads	11,470		$70.00	$90.00		—
2014	Swaps	2,218,500	$95.87				(2,042)
2014	Swaps with subfloors	2,004,000	$92.60	$70.00			(7,111)
2015	Two-way collars	108,500			$90.00	$99.86	275
2015	Three-way collars	263,500		$70.59	$90.59	$105.25	777
2015	Swaps	108,500	$93.07				148
2015	Swaps with subfloors	186,000	$92.60	$70.00			(6)
							$(4,730)

Interest rate risk. At December 31, 2013, we had $1,000.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% per annum, $400.0 million of senior unsecured notes at a fixed cash interest rate of 7.25% per annum, $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.875% and $400.0 million of senior unsecured notes at a fixed cash interest rate of 6.5% per annum outstanding. At December 31, 2013, we had $335.6 million of borrowings and $5.2 million of outstanding letters of credit issued under our revolving credit facility. We do not currently, but may in the future utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issued under our revolving credit facility. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.
Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we choose to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.
While we do not require all of our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation may include reviewing a counterparty’s credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record,

the financial ability of the customer’s parent company to make payment if the customer cannot and undertaking the due diligence necessary to determine credit terms and credit limits. Several of our significant customers for oil and natural gas receivables have a credit rating below investment grade or do not have rated debt securities. In these circumstances, we have considered the lack of investment grade credit rating in addition to the other factors described above.

As permitted under our investments policy, we may purchase commercial paper instruments from high credit quality counterparties. These counterparties may include issuers in a variety of industries including the domestic and foreign financial

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sector. This risk is managed by our investment policy including minimum credit ratings thresholds and maximum counterparty exposure values. Although we do not anticipate any of our commercial paper issuers failing to pay us upon maturity, we take a risk in purchasing the commercial paper instruments available in the marketplace. If an issuer fails to repay us at maturity from commercial paper proceeds, it could take a significant amount of time to recover a portion of or all of the assets originally invested. Our commercial paper balance was $36,000 at December 31, 2013.

In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties. However, in order to mitigate the risk of nonperformance, we only enter into derivative contracts with counterparties that are high credit-quality financial institutions. The counterparties on our derivative instruments currently in place are lenders under our revolving credit facility with investment grade ratings. We are likely to enter into any future derivative instruments with these or other lenders under our revolving credit facility, which also carry investment grade ratings. This risk is also managed by spreading our derivative exposure across several institutions and limiting the hedged volumes placed under individual contracts. Furthermore, the agreements with each of the counterparties on our derivative instruments contain netting provisions. As a result of these netting provisions, our maximum amount of loss due to credit risk is limited to the net amounts due to and from the counterparties under the derivative contracts. We had a net derivative asset position of $3.6 million and a net derivative liability position of $8.3 million at December 31, 2013.

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Item 8. Financial Statements and Supplementary Data
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Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Oasis Petroleum Inc.:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, of changes in stockholders' equity and of cash flows present fairly, in all material respects, the financial position of Oasis Petroleum Inc. and its subsidiaries (the "Company") at December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Company's internal control over financial reporting based on our audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers LLP

Houston, Texas

February 27, 2014

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Oasis Petroleum Inc.
Consolidated Balance Sheet

	December 31, 2013	2012
	(In thousands, except share data)	
ASSETS		
Current assets		
Cash and cash equivalents	$91,901	$213,447
Short-term investments	—	25,891
Accounts receivable — oil and gas revenues	175,653	110,341
Accounts receivable — joint interest partners	139,459	99,194
Inventory	20,652	20,707
Prepaid expenses	10,191	1,770
Advances to joint interest partners	760	1,985
Derivative instruments	2,264	19,016
Deferred income taxes	6,335	—
Other current assets	391	335
Total current assets	447,606	492,686
Property, plant and equipment		
Oil and gas properties (successful efforts method)	4,528,958	2,348,128
Other property and equipment	188,468	49,732
Less: accumulated depreciation, depletion, amortization and impairment	(637,676)	(391,260)
Total property, plant and equipment, net	4,079,750	2,006,600
Assets held for sale	137,066	—
Derivative instruments	1,333	4,981
Deferred costs and other assets	46,169	24,527
Total assets	$4,711,924	$2,528,794
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities		
Accounts payable	$8,920	$12,491
Advances from joint interest partners	12,829	21,176
Revenues and production taxes payable	146,741	71,553
Accrued liabilities	241,830	189,863
Accrued interest payable	47,910	30,096
Derivative instruments	8,188	1,048
Deferred income taxes	—	4,558
Total current liabilities	466,418	330,785
Long-term debt	2,535,570	1,200,000
Asset retirement obligations	35,918	22,956
Derivative instruments	139	380
Deferred income taxes	323,147	177,671
Other liabilities	2,183	1,997
Total liabilities	3,363,375	1,733,789
Commitments and contingencies (Note 17)		
Stockholders' equity		
Common stock, $0.01 par value; 300,000,000 shares authorized; 100,866,589 shares and 93,432,712 shares issued at December 31, 2013 and 2012, respectively	996	925
	(5,362)	(3,796)

Treasury stock, at cost; 167,155 shares and 129,414 shares at December 31, 2013 and 2012, respectively		
Additional paid-in-capital	985,023	657,943
Retained earnings	367,892	139,933
Total stockholders' equity	1,348,549	795,005
Total liabilities and stockholders' equity	$4,711,924	$2,528,794

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

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Oasis Petroleum Inc.
Consolidated Statement of Operations

	Year Ended December 31,		
	2013	2012	2011
	(In thousands, except per share data)		
Revenues			
Oil and gas revenues	$1,084,412	$670,491	$330,422
Well services and midstream revenues	57,587	16,177	—
Total revenues	1,141,999	686,668	330,422
Expenses			
Lease operating expenses	94,634	54,924	32,707
Well services and midstream operating expenses	30,713	11,774	—
Marketing, transportation and gathering expenses	25,924	9,257	1,365
Production taxes	100,537	62,965	33,865
Depreciation, depletion and amortization	307,055	206,734	74,981
Exploration expenses	2,260	3,250	1,685
Impairment of oil and gas properties	1,168	3,581	3,610
Loss on sale of properties	—	—	207
General and administrative expenses	75,310	57,190	29,435
Total expenses	637,601	409,675	177,855
Operating income	504,398	276,993	152,567
Other income (expense)			
Net gain (loss) on derivative instruments	(35,432)	34,164	1,595
Interest expense, net of capitalized interest	(107,165)	(70,143)	(29,618)
Other income (expense)	1,216	4,860	1,635
Total other income (expense)	(141,381)	(31,119)	(26,388)
Income before income taxes	363,017	245,874	126,179
Income tax expense	135,058	92,486	46,789
Net income	$227,959	$153,388	$79,390
Earnings per share:			
Basic (Note 14)	$2.45	$1.66	$0.86
Diluted (Note 14)	2.44	1.66	0.86
Weighted average shares outstanding:			
Basic (Note 14)	92,867	92,180	92,056
Diluted (Note 14)	93,411	92,513	92,241

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

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

	Common Stock		Treasury Stock		Additional Paid-in-Capital	Retained Earnings (Deficit)	Total Stockholders' Equity
	Shares	Amount	Shares	Amount			
Balance as of December 31, 2010	92,240	$920	—	$—	$643,719	$(92,845)	$551,794
Stock-based compensation	243	—	—	—	3,656	—	3,656
Vesting of restricted shares	—	1	—	—	(1)	—	—
Treasury stock – tax withholdings	(22)	—	22	(602)	—	—	(602)
Net income	—	—	—	—	—	79,390	79,390
Balance as of December 31, 2011	92,461	921	22	(602)	647,374	(13,455)	634,238
Stock-based compensation	949	—	—	—	10,573	—	10,573
Vesting of restricted shares	—	4	—	—	(4)	—	—
Treasury stock – tax withholdings	(107)	—	107	(3,194)	—	—	(3,194)
Net income	—	—	—	—	—	153,388	153,388
Balance as of December 31, 2012	93,303	925	129	(3,796)	657,943	139,933	795,005
Issuance of common stock	7,000	70	—	—	314,510	—	314,580
Stock-based compensation	434	—	—	—	12,571	—	12,571
Vesting of restricted shares	—	1	—	—	(1)	—	—
Treasury stock – tax withholdings	(38)	—	38	(1,566)	—	—	(1,566)
Net income	—	—	—	—	—	227,959	227,959
Balance as of December 31, 2013	100,699	$996	167	$(5,362)	$985,023	$367,892	$1,348,549

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

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Oasis Petroleum Inc.
Consolidated Statement of Cash Flows

	Year Ended December 31, 2013	2012	2011
	(In thousands)		
Cash flows from operating activities:			
Net income	$227,959	$153,388	$79,390
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	307,055	206,734	74,981
Impairment of oil and gas properties	1,168	3,581	3,610
Loss on sale of properties	—	—	207
Deferred income taxes	134,583	92,479	46,789
Derivative instruments	35,432	(34,164)	(1,595)
Stock-based compensation expenses	11,982	10,333	3,656
Debt discount amortization and other	4,248	2,810	1,561
Working capital and other changes:			
Change in accounts receivable	(107,473)	(90,103)	(64,900)
Change in inventory	(13,941)	(29,313)	(2,550)
Change in prepaid expenses	(8,191)	346	(1,600)
Change in other current assets	(56)	156	(491)
Change in other assets	(3,248)	(95)	(139)
Change in accounts payable and accrued liabilities	107,451	76,706	36,316
Change in other current liabilities	—	(472)	472
Change in other liabilities	887	—	317
Net cash provided by operating activities	697,856	392,386	176,024
Cash flows from investing activities:			
Capital expenditures	(893,524)	(1,051,365)	(613,720)
Acquisition of oil and gas properties	(1,560,072)	—	—
Derivative settlements	(8,133)	6,545	(3,841)
Purchases of short-term investments	—	(126,213)	(184,907)
Redemptions of short-term investments	25,000	120,316	164,913
Advances from joint interest partners	(8,347)	12,112	5,963
Proceeds from equipment and property sales	—	—	2,202
Net cash used in investing activities	(2,445,076)	(1,038,605)	(629,390)
Cash flows from financing activities:			
Proceeds from issuance of senior notes	1,000,000	400,000	800,000
Proceeds from revolving credit facility	600,000	—	—
Principal payments on revolving credit facility	(264,430)	—	—
Debt issuance costs	(22,910)	(8,012)	(18,680)
Proceeds from sale of common stock	314,580	—	—
Purchases of treasury stock	(1,566)	(3,194)	(602)
Net cash provided by financing activities	1,625,674	388,794	780,718
Increase (decrease) in cash and cash equivalents	(121,546)	(257,425)	327,352
Cash and cash equivalents:			
Beginning of period	213,447	470,872	143,520
End of period	$91,901	$213,447	$470,872
Supplemental cash flow information:			

Cash paid for interest, net of capitalized interest	$85,596	$53,488	$13,748
Cash paid for taxes	750	107	—
Supplemental non-cash transactions:			
Change in accrued capital expenditures	$34,354	$59,878	$58,205
Change in asset retirement obligations	13,201	10,230	5,434

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

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Oasis Petroleum Inc.
Notes to Consolidated Financial Statements
1. Organization and Operations of the Company
Organization
Oasis Petroleum Inc. (together with its subsidiaries, “Oasis” or the “Company”) was formed on February 25, 2010, pursuant to the laws of the State of Delaware, to become a holding company for Oasis Petroleum LLC (“OP LLC”), the Company’s predecessor, which was formed as a Delaware limited liability company on February 26, 2007. In connection with its initial public offering in June 2010 and related corporate reorganization, the Company acquired all of the outstanding membership interests in OP LLC in exchange for shares of the Company’s common stock. In 2007, Oasis Petroleum North America LLC (“OPNA”), a Delaware limited liability company, was formed to conduct domestic oil and natural gas exploration and production activities. In 2011, the Company formed Oasis Well Services LLC (“OWS”), a Delaware limited liability company, to provide well services to OPNA, and Oasis Petroleum Marketing LLC (“OPM”), a Delaware limited liability company, to provide marketing services to OPNA. In 2013, the Company formed Oasis Midstream Services LLC (“OMS”), a Delaware limited liability company, to provide midstream services to OPNA. As part of the formation of OMS, the Company transferred substantially all of its salt water disposal and other midstream assets from OPNA to OMS.
Nature of Business
The Company is an independent exploration and production company focused on the acquisition and development of unconventional oil and natural gas resources in the Williston Basin. The Company’s proved and unproved oil and natural gas properties are located in the North Dakota and Montana areas of the Williston Basin and are owned by OPNA. The Company also operates a marketing business (OPM), a well services business (OWS) and a midstream services business (OMS), all of which are complementary to its primary development and production activities. Both OWS and OMS are separate reportable business segments.
2. Summary of Significant Accounting Policies
Basis of Presentation
The accompanying consolidated financial statements of the Company include the accounts of Oasis and its wholly owned subsidiaries: OP LLC, OPNA, OWS, OMS and OPM. These statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“GAAP”). All significant intercompany transactions have been eliminated in consolidation. Certain reclassifications of prior year balances have been made to conform such amounts to current year classifications. These reclassifications have no impact on net income.
Use of Estimates
Preparation of the Company’s consolidated financial statements in accordance with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved oil and natural gas reserves and related cash flow estimates used in impairment tests of long-lived assets, estimates of future development, dismantlement and abandonment costs, estimates relating to certain oil and natural gas revenues and expenses and estimates of expenses related to legal, environmental and other contingencies. Certain of these estimates require assumptions regarding future commodity prices, future costs and expenses and future production rates. Actual results could differ from those estimates.
As an oil and natural gas producer, the Company’s revenue, profitability and future growth are substantially dependent upon the prevailing and future prices for oil and natural gas, which are dependent upon numerous factors beyond its control such as economic, political and regulatory developments and competition from other energy sources. The energy markets have historically been very volatile and there can be no assurance that oil and natural gas prices will not be subject to wide fluctuations in the future. A substantial or extended decline in oil and natural gas prices could have a material adverse effect on the Company’s financial position, results of operations, cash flows and quantities of oil and natural gas reserves that may be economically produced.
Estimates of oil and natural gas reserves and their values, future production rates and future costs and expenses are inherently uncertain for numerous reasons, including many factors beyond the Company’s control. Reservoir engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be

measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of data available and of engineering and geological interpretation and judgment. In addition, estimates of reserves may be revised based on actual production, results of subsequent exploration and development activities, prevailing commodity prices, operating costs and other factors. These revisions may be material and could materially affect future depletion, depreciation and amortization expense, dismantlement and abandonment costs, and impairment expense.

Cash Equivalents and Short-Term Investments

The Company invests in certain money market funds, commercial paper and time deposits, all of which are stated at fair value or cost which approximates fair value due to the short-term maturity of these investments. The Company classifies all such investments with original maturity dates less than 90 days as cash equivalents. The Company classifies all such investments with original maturity dates greater than 90 days as held-to-maturity securities based on management's intentions to hold the investments to their maturity dates.

Accounts Receivable

Accounts receivable are carried on a gross basis, with no discounting. The Company regularly reviews all aged accounts receivable for collectability and establishes an allowance as necessary for individual customer balances. No allowance for doubtful accounts was recorded for the years ended December 31, 2013 and 2012.

Inventory

Equipment and materials consist primarily of tubular goods, well equipment to be used in future drilling or repair operations and well fracturing equipment, chemicals and proppant, all of which are stated at the lower of cost or market with cost determined on an average cost method. Crude oil inventories include oil in tank and line fill and are valued at the lower of average cost or market value. Inventory consists of the following:

	December 31,	
	2013	2012
	(In thousands)	
Equipment and materials	$11,669	$16,438
Crude oil inventory	8,983	4,269
	$20,652	$20,707

Joint Interest Partner Advances

The Company participates in the drilling of oil and natural gas wells with other working interest partners. Due to the capital intensive nature of oil and natural gas drilling activities, the working interest partner responsible for conducting the drilling operations may request advance payments from other working interest partners for their share of the costs. The Company expects such advances to be applied by working interest partners against joint interest billings for its share of drilling operations within 90 days from when the advance is paid.

Property, Plant and Equipment

Proved Oil and 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 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 depreciation, depletion and amortization ("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. In November 2011, the Company sold its remaining interests in non-core oil and natural gas producing properties located in the Barnett shale in Texas and interests in

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other properties for an aggregate $2.2 million in cash. The Company recognized a loss of $0.2 million from these divestures. No gain or loss for the sale of oil and natural gas properties was recorded for the years ended December 31, 2013 or 2012.

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.

The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such undiscounted future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs, as further discussed in Note 3 — Fair Value Measurements. No impairment of proved oil and natural gas properties was recorded for the years ended December 31, 2013, 2012 and 2011.

Unproved Oil and Gas Properties

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 the Company specifically identifies leases that will revert to the lessor, at which time the Company expenses the associated lease acquisition costs. The expensing of the lease acquisition costs is recorded as impairment of oil and gas properties in the 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.

The Company assesses its unproved properties periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results or future plans to develop acreage. The Company considers the following factors in its assessment of the impairment of unproved properties:

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

As a result of expiring unproved property leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges of $1.2 million for the year ended December 31, 2013 and $3.6 million for each of the years ended ended December 31, 2012 and 2011.

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.

Capitalized Interest

The Company capitalizes a portion of its interest expense incurred on its outstanding debt. The amount capitalized is determined by multiplying the capitalization rate by the average amount of eligible accumulated capital expenditures and is limited to actual interest costs incurred during the period. The accumulated capital expenditures included in the capitalized interest calculation begin when the first costs are incurred and end when the asset is either placed into production or written off. The Company capitalized $4.6 million, $3.3 million and $3.1 million of interest costs for the years ended December 31, 2013, 2012 and 2011, respectively. These amounts will be amortized over the life of the related assets.

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Other Property and Equipment

Salt water disposal facilities, furniture, software, equipment and leasehold improvements are recorded at cost and are depreciated on the straight-line method based on expected lives of the individual assets. The Company uses estimated lives of 30 years for salt water disposal facilities, 20 years for buildings, two to seven years for furniture, software and equipment and the remaining lease term for leasehold improvements. The calculation for the straight-line DD&A method for salt water disposal facilities takes into consideration estimated future dismantlement, restoration and abandonment costs, which are net of estimated salvage values. The cost of assets disposed of and the associated accumulated depletion, depreciation and amortization are removed from the Company's Consolidated Balance Sheet with any gain or loss realized upon the sale or disposal included in the Company's Consolidated Statement of Operations.

Exploration Expenses

Exploration costs, including certain geological and geophysical expenses and the costs of carrying and retaining undeveloped acreage, are charged to expense as incurred.

Costs from drilling exploratory wells are initially capitalized, but charged to expense if and when a well is determined to be unsuccessful. Determination is usually made on or shortly after drilling or completing the well, however, in certain situations a determination cannot be made when drilling is completed. The Company defers capitalized exploratory drilling costs for wells that have found a sufficient quantity of producible hydrocarbons but cannot be classified as proved because they are located in areas that require major capital expenditures or governmental or other regulatory approvals before production can begin. These costs continue to be deferred as wells-in-progress as long as development is underway, is firmly planned for the near future or the necessary approvals are actively being sought.

Net changes in capitalized exploratory well costs are reflected in the following table for the periods presented:

	December 31, 2013	2012	2011
	(In thousands)		
Beginning of period	$40,424	$20,207	$5,176
Exploratory well cost additions (pending determination of proved reserves)	346,814	160,813	73,947
Exploratory well cost reclassifications (successful determination of proved reserves)	(264,023)	(140,091)	(57,646)
Exploratory well dry hole costs (unsuccessful in adding proved reserves)	—	(505)	(1,270)
End of period	$123,215	$40,424	$20,207

As of December 31, 2013, the Company had no exploratory well costs that were capitalized for a period greater than one year.

Business Combinations

The Company accounts for business combinations under the acquisition method of accounting. Accordingly, the Company recognizes 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.

The Company makes 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 additional project-specific risking factors. In addition, when appropriate, the Company reviews comparable purchases and sales of oil and natural gas properties within the same regions, and uses 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

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assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Assets Held for Sale

The Company occasionally markets non-core oil and gas properties. At the end of each reporting period, the Company evaluates the properties being marketed to determine whether any should be reclassified as held-for-sale. The held-for-sale criteria include: management commits to a plan to sell; the asset is available for immediate sale; an active program to locate a buyer exists; the sale of the asset is probable and expected to be completed within one year; the asset is being actively marketed for sale; and it is unlikely that significant changes to the plan will be made. If each of these criteria is met, the property is reclassified as held-for-sale in the Company's Consolidated Balance Sheet and measured at the lower of their carrying amount or estimated fair value less costs to sell. Depreciation, depletion, and amortization expense is not recorded on assets to be divested once they are classified as held for sale.

Deferred Financing Costs

The Company capitalizes costs incurred in connection with obtaining financing. These costs are included in deferred costs and other assets on the Company's Consolidated Balance Sheet and are amortized over the term of the related financing using the straight-line method, which approximates the effective interest method. The amortization expense is recorded as a component of interest expense in the Company's Consolidated Statement of Operations.

Asset Retirement Obligations

In accordance with the Financial Accounting Standard Board's ("FASB") authoritative guidance on asset retirement obligations ("ARO"), the Company records 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 the Company 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 using the unit-of-production method. The accretion expense is recorded as a component of depreciation, depletion and amortization in the Company's Consolidated Statement of Operations.

The Company determines the ARO by calculating the present value of estimated cash flows related to the liability. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. These assumptions represent Level 3 inputs, as further discussed in Note 3 — Fair Value Measurements. 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.

Revenue Recognition

Oil and gas revenue from the Company's 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 the Company's production is sold to purchasers under short-term (less than twelve months) 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, the Company sells the majority of its production soon after it is produced at various locations. As a result, the Company maintains a minimum amount of product inventory in storage.

Well services revenue is recognized when well completion services have been performed or related products have been delivered. OWS provides wells services and sells related products primarily to OPNA. Midstream revenues consist of revenues from salt water disposal 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 the Company's Consolidated Statement of Operations.

Revenues and Production Taxes Payable

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The Company calculates and pays taxes and royalties on oil and natural gas in accordance with the particular contractual provisions of the lease, license or concession agreements and the laws and regulations applicable to those agreements.

Concentrations of Market and Credit Risk

The future results of the Company's oil and natural gas operations will be affected by the market prices of oil and natural gas. The availability of a ready market for oil and natural gas products in the future will depend on numerous factors beyond the control of the Company, including weather, imports, marketing of competitive fuels, proximity and capacity of oil and natural gas pipelines and other transportation facilities, any oversupply or undersupply of oil, natural gas and liquid products, the regulatory environment, the economic environment, and other regional and political events, none of which can be predicted with certainty.

The Company operates in the exploration, development and production sector of the oil and gas industry. The Company's receivables include amounts due from purchasers of its oil and natural gas production and amounts due from joint interest partners for their respective portions of operating expenses and exploration and development costs. While certain of these customers and joint interest partners are affected by periodic downturns in the economy in general or in their specific segment of the oil or natural gas industry, the Company believes that its level of credit-related losses due to such economic fluctuations has been and will continue to be immaterial to the Company's results of operations over the long-term. In addition, a portion of the Company's trade receivables are collateralized.

The Company manages and controls market and counterparty credit risk. In the normal course of business, collateral is not required for financial instruments with credit risk. Financial instruments which potentially subject the Company to credit risk consist principally of temporary cash balances and derivative financial instruments. The Company maintains cash and cash equivalents in bank deposit accounts which, at times, may exceed the federally insured limits. The Company has not experienced any significant losses from such investments. The Company attempts to limit the amount of credit exposure to any one financial institution or company. The Company believes the credit quality of its customers is generally high. In the normal course of business, letters of credit or parent guarantees are required for counterparties which management perceives to have a higher credit risk.

Risk Management

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2013, the Company utilized two-way and three-way costless collar options, put spreads, swaps and swaps with sub-floors to reduce the volatility of oil prices on a significant portion of the Company's future expected oil production (see Note 4 — Derivative Instruments).

The Company records all derivative instruments on the Consolidated Balance Sheet as either assets or liabilities measured at their estimated fair value. 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. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. Cash settlements of commodity derivative instruments and gains and losses from valuation changes in the remaining unsettled commodity derivative instruments are reported in the other income (expense) section of the Company's Consolidated Statement of Operations. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company's Consolidated Statement of Cash Flows.

Derivative financial instruments that hedge the price of oil are executed with major financial institutions that expose the Company to market and credit risks and which may, at times, be concentrated with certain counterparties or groups of counterparties. The Company has derivatives in place with six counterparties. Although notional amounts are used to express the volume of these contracts, the amounts potentially subject to credit risk in the event of nonperformance by the counterparties are substantially smaller. The credit worthiness of the counterparties is subject to continual review. The Company believes the risk of nonperformance by its counterparties is low. Full performance is anticipated, and the Company has no past-due receivables from its counterparties. The Company's policy is to execute financial derivatives only with major, credit-worthy financial institutions.

The Company's derivative contracts are documented with industry standard contracts known as a Schedule to the Master Agreement and International Swaps and Derivative Association, Inc. Master Agreement ("ISDA"). Typical terms for the ISDAs include credit support requirements, cross default provisions, termination events and set-off provisions. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the properties securing the Company's revolving credit facility (see Note 9 — Long-Term Debt). As of December 31, 2013, the Company had limitations under its revolving credit facility, including a provision limiting the total amount of production that may be hedged by the Company to the lesser of projected production or 110% of Current Production (as defined in the revolving credit facility) for the period from 1 to 12 months, 100% of Current Production for the period from 13 to 24 months, 75% of Current Production for the period from 25 to 36 months, and 50% of Current Production for the period from 37 to 60 months after the date of each derivative. As of December 31, 2013, the Company was in compliance with these limitations.

Environmental Costs

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and which do not have future economic benefit, are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

Stock-Based Compensation

Restricted Stock Awards

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

Performance Share Units

The Company recognizes compensation expense for its performance share units ("PSUs") granted to its officers under its 2010 Long-Term Incentive Plan. 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. Any change in inputs or number of inputs to this calculation could impact the valuation and thus the stock-based compensation expense recognized (see Note 12 — Stock-Based Compensation for a description of these inputs). Stock-based compensation expense recorded for PSUs is included in general and administrative expenses on the Company's Consolidated Statement of Operations.

Associated Excess Tax Benefits

Any excess tax benefit arising from the Company's stock-based compensation plan is recognized as a credit to additional paid-in-capital when realized and is calculated as the amount by which the tax benefit related to the tax deduction received exceeds the deferred tax asset associated with the recorded stock-based compensation expense. As of December 31, 2013, the excess federal tax deduction related to stock-based compensation was $4.8 million and the excess state tax deduction related to stock-based compensation was $3.5 million. Since the Company has been in and continues to be in a net operating loss position for tax purposes, none of the excess tax deduction is reflected in additional paid-in-capital. Pursuant to GAAP, the Company's deferred tax asset related to net operating loss carryforward is net of the unrealized tax benefit from stock-based compensation.

Treasury Stock

Treasury stock shares represent shares withheld by the Company equivalent to the payroll tax withholding obligations due from employees upon the vesting of restricted stock awards. The Company includes the withheld shares as treasury stock on its Consolidated Balance Sheet and separately pays the payroll tax obligation. These retained shares are not part of a publicly announced program to repurchase shares of the Company's common stock and are accounted for at cost. The Company does not have a publicly announced program to repurchase shares of its common stock.

Income Taxes

The Company's provision for taxes includes both federal and state taxes. The Company records its federal income taxes in accordance with accounting for income taxes under GAAP which results in the recognition of deferred tax assets and

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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.

The Company applies significant judgment in evaluating its tax positions and estimating its 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 the Company's estimates, which could impact its financial position, results of operations and cash flows.

The Company also accounts 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 the Company 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. The Company did not have any uncertain tax positions outstanding and, as such, did not record a liability for the years ended December 31, 2013 and 2012.

Fair Value of Financial and Non-Financial Instruments

The carrying value of cash and cash equivalents, accounts receivable, accounts payable and other payables approximate their respective fair market values due to their short-term maturities. The Company's derivative instruments and asset retirement obligations are also recorded on the Consolidated Balance Sheet at amounts which approximate fair market value. See Note 3 — Fair Value Measurements.

3. Fair Value Measurements

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

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

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

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

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

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

Financial Assets and Liabilities

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

	At fair value as of December 31, 2013			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$742	$—	$—	$742
Commodity derivative instruments (see Note 4)	—	3,597	—	3,597
Total assets	$742	$3,597	$—	$4,339
Liabilities:				
Commodity derivative instruments (see Note 4)	$—	$8,327	$—	$8,327
Total liabilities	$—	$8,327	$—	$8,327

	At fair value as of December 31, 2012			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Assets:				
Money market funds	$66,387	$—	$—	$66,387
Commodity derivative instruments (see Note 4)	—	23,997	—	23,997
Total assets	$66,387	$23,997	$—	$90,384
Liabilities:				
Commodity derivative instruments (see Note 4)	$—	$1,428	$—	$1,428
Total liabilities	$—	$1,428	$—	$1,428

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

The Level 2 instruments presented in the tables above consist of commodity derivative instruments, which include oil collars, swaps and puts. The fair values of the Company's commodity derivative instruments are based upon a third-party preparer's calculation using mark-to-market valuation reports provided by the Company's counterparties for monthly settlement purposes to determine the valuation of its derivative instruments. The Company has the third-party preparer evaluate other readily available market prices for its derivative contracts as there is an active market for these contracts. The third-party preparer performs its independent valuation using a moment matching method similar to Turnbull-Wakeman for Asian options. The significant inputs used are crude oil prices, volatility, skew, discount rate and the contract terms of the derivative instruments. However, the Company does not have access to the specific proprietary valuation models or inputs used by its counterparties or third-party preparer. The determination of the fair value for derivative instruments also incorporates a credit adjustment for non-performance risk, as required by GAAP. The Company calculated the credit adjustment for derivatives in an asset position using current credit default swap values for each counterparty. The credit adjustment for derivatives in a liability position is based on the Company's market credit spread. Based on these calculations, the Company recorded a downward adjustment to the fair value of its net derivative liability in the amount of $0.2 million at December 31, 2013 and a downward adjustment to the fair value of its net derivative asset in the amount of $29,000 at December 31, 2012.

The following table presents a reconciliation of the changes in fair value of the derivative instruments classified as Level 3 in the fair value hierarchy for the years presented. The Level 3 instruments presented below consist of derivative instruments, which include oil collars, swaps and puts.

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	2013	2012	2011
	(In thousands)		
Balance as of January 1	$—	$(5,050)	$(10,486)
Total gains or (losses):			
Included in earnings	—	—	1,595
Included in other comprehensive income	—	—	—
Purchases, issuances and settlements	—	—	3,841
Transfers in and out of Level 3[(1)]	—	5,050	—
Balance as of December 31	$—	$—	$(5,050)
Change in fair value included in earnings relating to derivatives instruments still held at December 31	$—	$—	$5,436

(1) During the year ended December 31, 2012, the inputs used to value the Company's commodity derivative instruments were directly or indirectly observable and those contracts were transferred to Level 2.

Fair Value of Other Financial Instruments

The Company's financial instruments, including certain cash and cash equivalents, short-term investments, accounts receivable and accounts payable, are carried at cost, which approximates fair value due to the short-term maturity of these instruments. At December 31, 2013, the Company's cash equivalents were all Level 1 assets. The carrying amount of the Company's long-term debt reported in the Consolidated Balance Sheet at December 31, 2013 is $2,535.6 million, which includes $2,200.0 million of senior unsecured notes and $335.6 million of borrowings under the Company's revolving credit facility (see Note 9 — Long-Term Debt). The fair value of the Company's senior unsecured notes, which are publicly traded and therefore categorized as Level 1 liabilities, is $2,344.0 million at December 31, 2013.

Nonfinancial Assets and Liabilities

Asset retirement obligations. The carrying amount of the Company's ARO in the Consolidated Balance Sheet at December 31, 2013 is $36.5 million (see Note 10 — Asset Retirement Obligations). The Company determines 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. These assumptions represent Level 3 inputs. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Impairment. The Company reviews its proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Company estimates the expected undiscounted future cash flows of its oil and natural gas properties and compares such amounts to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company will adjust the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value are subject to management's judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk and current market conditions associated with realizing the expected cash flows projected. These assumptions represent Level 3 inputs. No impairment charges on proved oil and natural gas properties were recorded for the year ended December 31, 2013, 2012 or 2011.

4. Derivative Instruments

The Company utilizes derivative financial instruments to manage risks related to changes in oil prices. As of December 31, 2013, the Company utilized two-way and three-way costless collar options, put spreads, swaps and swaps with sub-floors to reduce the volatility of oil prices on a significant portion of the Company's future expected oil production. A two-way collar is a combination of options: a sold call and a purchased put. The purchased put establishes a minimum price (floor) and the sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A three-way collar is a combination of options: a sold call, a purchased put and a sold put. The purchased put establishes a minimum price (floor), unless the market price falls below the sold put (sub-floor), at which point the minimum price would be NYMEX West Texas Intermediate (“WTI”) crude oil index price plus the difference between the purchased put and the sold put strike

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price. The sold call establishes a maximum price (ceiling) the Company will receive for the volumes under contract. A put spread is a combination of a purchased put and a sold put, and in this case does not include a sold call, allowing the volumes under this contract to have no established maximum price (ceiling). A swap is a sold call and a purchased put established at the same price (both ceiling and floor). A swap with a sub-floor is a swap coupled with a sold put (sub-floor) at which point the minimum price would be WTI crude oil index price plus the difference between the swap and the sold put strike price.

All derivative instruments are recorded on the Consolidated Balance Sheet as either assets or liabilities measured at their fair value (see Note 3 — Fair Value Measurements). Derivative assets and liabilities arising from the Company's derivative contracts with the same counterparty are also reported on a net basis, as all counterparty contracts provide for net settlement. The Company has not designated any derivative instruments as hedges for accounting purposes and does not enter into such instruments for speculative trading purposes. If a derivative does not qualify as a hedge or is not designated as a hedge, the changes in the fair value, both cash settlements and non-cash changes in fair value, are recognized in the other income (expense) section of the Company's Consolidated Statement of Operations as a gain or loss on derivative instruments. The Company's cash flow is only impacted when the actual settlements under the derivative contracts result in making or receiving a payment to or from the counterparty. These cash settlements are reflected as investing activities in the Company's Consolidated Statement of Cash Flows.

As of December 31, 2013, the Company had the following outstanding commodity derivative instruments, all of which settle monthly based on the WTI crude oil index price:

Settlement Period	Derivative Instrument	Total Notional Amount of Oil	Weighted Average Prices Swap	Sub-Floor	Floor	Ceiling	Fair Value Asset (Liability)
		(Barrels)	($/Barrel)				(In thousands)
2014	Two-way collars	1,510,000			$90.77	$102.06	$302
2014	Three-way collars	3,530,530		$70.30	$90.65	$105.64	2,927
2014	Put spreads	11,470		$70.00	$90.00		—
2014	Swaps	2,218,500	$95.87				(2,042)
2014	Swaps with subfloors	2,004,000	$92.60	$70.00			(7,111)
2015	Two-way collars	108,500			$90.00	$99.86	275
2015	Three-way collars	263,500		$70.59	$90.59	$105.25	777
2015	Swaps	108,500	$93.07				148
2015	Swaps with subfloors	186,000	$92.60	$70.00			(6)
							$(4,730)

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

Fair Value of Derivative Instrument Assets (Liabilities)

Commodity	Balance Sheet Location	Fair Value December 31, 2013	2012
		(In thousands)	
Crude oil	Derivative instruments — current assets	$2,264	$19,016
Crude oil	Derivative instruments — non-current assets	1,333	4,981
Crude oil	Derivative instruments — current liabilities	(8,188)	(1,048)
Crude oil	Derivative instruments — non-current liabilities	(139)	(380)
Total derivative instruments		$(4,730)	$22,569

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

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	Statement of Operations Location	December 31, 2013	2012	2011
		(In thousands)		
Change in fair value of derivative instruments	Net gain (loss) on derivative instruments	$(27,299)	$27,619	$5,436
Derivative settlements	Net gain (loss) on derivative instruments	(8,133)	6,545	(3,841)
Total net gain (loss) on derivative instruments		$(35,432)	$34,164	$1,595

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

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

Offsetting of Derivative Assets	Gross Amounts of Recognized Assets	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets Presented in the Balance Sheet
	(In thousands)		
As of December 31, 2013	$22,743	$(19,146)	$3,597
As of December 31, 2012	$68,970	$(44,973)	$23,997

Offsetting of Derivative Liabilities	Gross Amounts of Recognized Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Liabilities Presented in the Balance Sheet
	(In thousands)		
As of December 31, 2013	$27,473	$(19,146)	$8,327
As of December 31, 2012	$46,401	$(44,973)	$1,428

5. Property, Plant and Equipment

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

	December 31, 2013	2012
	(In thousands)	
Proved oil and gas properties(1)	$3,713,525	$2,271,711
Less: Accumulated depreciation, depletion, amortization and impairment	(612,380)	(383,564)
Proved oil and gas properties, net(2)	3,101,145	1,888,147
Unproved oil and gas properties	815,433	76,417
Other property and equipment	188,468	49,732
Less: Accumulated depreciation	(25,296)	(7,696)
Other property and equipment, net(2)	163,172	42,036
Total property, plant and equipment, net	$4,079,750	$2,006,600

(1) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $32.6 million and $20.7 million at December 31, 2013 and 2012, respectively.

(2)

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

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Asset impairments. As discussed in Note 2, as a result of expiring leases and periodic assessments of unproved properties, the Company recorded non-cash impairment charges on its unproved oil and gas properties of $1.2 million for the year ended December 31, 2013 and $3.6 million for each of the years ended December 31, 2012 and 2011. No impairment of proved oil and natural gas properties was recorded for the years ended December 31, 2013, 2012, and 2011.

6. Acquisitions

The following table summarizes the consideration paid for the Company's acquisitions during the year ended December 31, 2013 and the fair value of the assets acquired and liabilities assumed as of the acquisition dates. The purchase price allocations are preliminary and subject to adjustment, as the final closing statements will be completed by the second quarter of 2014.

	Year Ended December 31, 2013	
	West Williston	East Nesson
Consideration given to the sellers:	(In thousands)	
Cash	$1,496,369	$55,339
Forgiveness of debt	—	1,896
Total consideration	1,496,369	57,235
Recognized amounts of identifiable assets acquired and liabilities assumed:		
Assets acquired:		
Proved developed properties	535,477	32,511
Proved undeveloped properties	165,907	1,807
Unproved lease acquisition costs	787,589	23,369
Other property and equipment	13,157	—
Inventory	3,181	148
Total assets acquired	1,505,311	57,835
Liabilities assumed:		
Asset retirement obligations	6,598	307
Revenues payable	2,344	293
Total liabilities assumed	8,942	600
Total identifiable net assets	$1,496,369	$57,235

West Williston acquisition. On October 1, 2013, the Company completed a purchase and sale agreement (the "Purchase Agreement") with two undisclosed private sellers (the "Sellers"), pursuant to which the Company agreed to purchase approximately 136,000 net acres in its West Williston project area in the Williston Basin (the "West Williston Acquisition") for aggregate consideration of $1,496.4 million in cash (the "Purchase Price"), which is subject to further customary post close adjustments.

The West Williston Acquisition qualified as a business combination, and as such, the Company estimated the fair value of the assets acquired and liabilities assumed as of the October 1, 2013 acquisition date. The fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements also utilize assumptions of market participants. The Company used a discounted cash flow model and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. These assumptions represent Level 3 inputs, as further discussed under Note 3 — Fair Value Measurements.

The Company recorded the assets acquired and liabilities assumed in the West Williston Acquisition at their estimated fair value of $1,496.4 million, which the Company considers to be representative of the price paid by a typical market participant. This measurement resulted in no goodwill or bargain purchase being recognized. In addition, the

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included $2.0 million of costs related to the West Williston Acquisition in general and administrative expenses on its Consolidated Statement of Operations for the year ended December 31, 2013.

The results of operations for the West Williston Acquisition have been included in the Company's consolidated financial statements since the October 1, 2013 closing date, including approximately$57.6 million of total revenue and $14.9 million of operating income. Summarized below are the consolidated results of operations for the years ended December 31, 2013 and 2012, on an unaudited pro forma basis, as if the acquisition and related financing had occurred on January 1, 2012. The unaudited pro forma financial information was derived from the historical consolidated statement of operations of the Company and the statement of revenues and direct operating expenses for the West Williston Acquisition properties, which were derived from the historical accounting records of the Sellers. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the acquisition and related financing occurred on the basis assumed above, nor is such information indicative of the Company's expected future results of operations.

	Year Ended December 31,	
	2013	2012
	(In thousands)	
	Unaudited	
Revenues	$1,297,545	$831,575
Net income	231,217	136,004

East Nesson acquisitions. On September 26, 2013, the Company acquired certain oil and natural gas assets totaling approximately 25,000 net acres in its East Nesson project area for total consideration of $57.2 million, subject to further customary post close adjustments (the "East Nesson Acquisitions"). As part of the East Nesson Acquisitions, the Company also agreed to invest, expend and/or incur expenses of $8.2 million in connection with drilling and completion activities for certain wells (see Note 17 — Commitments and Contingencies).

The results of operations for the East Nesson Acquisitions have been included in the Company's consolidated financial statements since the September 26, 2013 closing date. Pro forma information is not presented as the pro forma results would not be materially different from the information presented in the Company's Consolidated Statement of Operations.

The Company did not have any significant acquisitions for the years ended December 31, 2012 and 2011.

7. Assets Held for Sale

Net assets held for sale represent the assets that were or are expected to be sold, net of liabilities, which were or are expected to be assumed by the purchaser. As of December 31, 2013, the assets in the Company's Sanish project area and other non-operated leases adjacent to its Sanish position in North Dakota were held for sale (see Note 18 — Subsequent Events). The Company did not have assets classified as held for sale as of December 31, 2012. The following table presents balance sheet data related to the assets held for sale:

	December 31, 2013
	(In thousands)
Assets	
Oil and gas properties	$191,384
Less: accumulated depreciation, depletion, amortization and impairment	(54,318)
Total assets	$137,066
Liabilities	
Asset retirement obligation	$1,973
Total liabilities	$1,973
Net assets	$135,093

8. Accrued Liabilities

The Company’s accrued liabilities consist of the following:

	December 31,	
	2013	2012
	(In thousands)	
Accrued capital costs	$199,085	$167,246
Accrued lease operating expenses	18,660	9,786
Accrued general and administrative expenses	14,203	7,703
Other accrued liabilities	9,882	5,128
Total accrued liabilities	$241,830	$189,863

Accrued liabilities represent the Company’s estimated current payment obligations for materials and services provided by its vendors, for which invoices have not yet been received or fully processed. Invoices that have been fully processed, but not yet paid, are recorded as accounts payable.

In addition, the Company had revenue suspense of $79.7 million, production taxes payable of $22.3 million and royalties payable of $44.7 million included in revenues and production taxes payable on the Consolidated Balance Sheet for the year ended December 31, 2013. For the year ended December 31, 2012, the Company had revenue suspense of $30.0 million, production taxes payable of $11.6 million and royalties payable of $27.8 million included in revenues and production taxes payable on the Consolidated Balance Sheet. Revenue suspense represents proceeds from the sale of oil and natural gas production that have been processed by the Company on behalf of third parties, which cannot be disbursed to such third parties until certain issues are resolved, such as title issues or missing contact information.

9. Long-Term Debt

Senior unsecured notes. On September 24, 2013, the Company issued $1,000.0 million of 6.875% senior unsecured notes due March 15, 2022 (the “2022 Notes”). The issuance of the 2022 Notes resulted in aggregate net proceeds to the Company of approximately $983.6 million. The Company used the proceeds from the 2022 Notes to fund the acquisition of oil and gas properties in its West Williston project area (see Note 6 — Acquisitions).

In connection with the issuance of the 2022 Notes, the Company along with its material subsidiaries (the “Guarantors”) entered into a registration rights agreement pursuant to which the Company and Guarantors agreed to file a registration statement with the SEC to allow the holders of the 2022 Notes to exchange the 2022 Notes for the same principal amount of a new issue of notes with substantially identical terms, except the new notes will be freely transferable under the Securities Act. The Company and the Guarantors will use commercially reasonable efforts to cause the exchange to be completed within 360 days after the 2022 Notes issuance date. Under certain circumstances, in lieu of a registered exchange offer, the Company must use commercially reasonable efforts to file a shelf registration statement for the resale of the 2022 Notes. If the Company fails to satisfy these obligations on a timely basis, the annual interest borne by the 2022 Notes will be increased by 1.0% per annum until the exchange offer is completed or the shelf registration statement is declared effective. The Company estimates the value of this contingent interest is immaterial at December 31, 2013.

During 2011 and 2012, the Company issued $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”) and $400.0 million of 6.875% senior unsecured notes due January 15, 2023 (the “2023 Notes”), which resulted in aggregate net proceeds to the Company of approximately $1,175.8 million. The Company has used the proceeds from these notes to fund its exploration, development and acquisition program and for general corporate purposes. Interest on these notes is payable semi-annually in arrears.

The 2022 Notes, the 2019 Notes, the 2021 Notes and the 2023 Notes (collectively, the “Notes”) are guaranteed on a senior unsecured basis by the Company’s Guarantors. These guarantees are full and unconditional and joint and several among the Guarantors, subject to certain customary release provisions, as follows:

- in connection with any sale or other disposition of all or substantially all of the assets of that Guarantor (including by way of merger or consolidation) to a person that is not (either before or after giving effect to such transaction) the Company or a restricted subsidiary of the Company;

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

The Notes were issued under indentures containing provisions that are substantially the same, as amended and supplemented by supplemental indentures (collectively the "Indentures"), among the Company, the Guarantors and U.S. Bank National Association, as trustee (the "Trustee"). Prior to certain dates, the Company has certain options to redeem up to 35% of the Notes at a certain redemption price based on a percentage of the principal amount, plus accrued and unpaid interest to the redemption date, with the proceeds of certain equity offerings so long as the redemption occurs within 180 days of completing such equity offering and at least 65% of the aggregate principal amount of the Notes remains outstanding after such redemption. Prior to certain dates, the Company has the option to redeem some or all of the Notes for cash at certain redemption prices equal to a certain percentage of their principal amount plus an applicable make-whole premium and accrued and unpaid interest to the redemption date. The Company estimates that the fair value of these options is immaterial at December 31, 2013 and 2012.

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

The Indentures contain customary events of default, including:

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

Senior secured revolving line of credit. On April 5, 2013, the Company, as parent, and OPNA, as borrower, entered into a second amended and restated credit agreement (the "Second Amended Credit Facility"), which has a maturity date of April 5, 2018. The Second Amended Credit Facility is restricted to the borrowing base, which is reserve-based and subject to semi-annual redeterminations on April 1 and October 1 of each year. Borrowings under the Second Amended Credit Facility are collateralized by perfected first priority liens and security interests on substantially all of the Company's assets, including mortgage liens on oil and natural gas properties having at least 80% of the reserve value as determined by reserve reports.

In connection with entry into the Second Amended Credit Facility, the semi-annual redetermination of the Company's borrowing base was also completed on April 5, 2013, which increased the borrowing base of the Second Amended

Credit Facility from $750.0 million to $1,250.0 million. However, the Company elected to limit the aggregate commitment of the

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lenders under the Second Amended Credit Facility (the "Lenders") to $900.0 million. In addition, under the Second Amended Credit Facility, the overall credit facility increased from $1.0 billion to $2.5 billion.

On September 3, 2013, the Company entered into an amendment to its Second Amended Credit Facility (the "Amendment"). In connection with the Amendment, the Lenders under the Company's Second Amended Credit Facility completed their regular semi-annual redetermination of the borrowing base scheduled for October 1, 2013. Following the redetermination, the Company's borrowing base increased from $1,250.0 million to $1,500.0 million and elected commitments also totaled $1,500.0 million.

Borrowings under the Second Amended Credit Facility are subject to varying rates of interest based on (1) the total outstanding borrowings (including the value of all outstanding letters of credit) in relation to the borrowing base and (2) whether the loan is a London interbank offered rate ("LIBOR") loan or a domestic bank prime interest rate loan (defined in the Second Amended Credit Facility as an Alternate Based Rate or "ABR" loan). As of December 31, 2013, any outstanding LIBOR and ABR loans would have borne their respective interest rates plus the applicable margin indicated in the following table:

Ratio of Total Outstanding Borrowings to Borrowing Base	Applicable Margin for LIBOR Loans		Applicable Margin for ABR Loans	
Less than .25 to 1	1.50	%	0.00	%
Greater than or equal to .25 to 1 but less than .50 to 1	1.75	%	0.25	%
Greater than or equal to .50 to 1 but less than .75 to 1	2.00	%	0.50	%
Greater than or equal to .75 to 1 but less than .90 to 1	2.25	%	0.75	%
Greater than .90 to 1 but less than or equal 1	2.50	%	1.00	%

An ABR loan may be repaid at any time before the scheduled maturity of the Second Amended Credit Facility upon the Company providing advance notification to the Lenders. Interest is paid quarterly on ABR loans based on the number of days an ABR loan is outstanding as of the last business day in March, June, September and December. The Company has the option to convert an ABR loan to a LIBOR-based loan upon providing advance notification to the Lenders. The minimum available loan term is one month and the maximum available loan term is six months for LIBOR-based loans. Interest for LIBOR loans is paid upon maturity of the loan term. Interim interest is paid every three months for LIBOR loans that have loan terms greater than three months. At the end of a LIBOR loan term, the Second Amended Credit Facility allows the Company to elect to repay the borrowing, continue a LIBOR loan with the same or differing loan term or convert the borrowing to an ABR loan.

On a quarterly basis, the Company also pays a 0.375% (as of December 31, 2013) annualized commitment fee on the average amount of borrowing base capacity not utilized during the quarter and fees calculated on the average amount of letter of credit balances outstanding during the quarter.

As of December 31, 2013, the Second Amended Credit Facility contained covenants that included, among others:

- a prohibition against incurring debt, subject to permitted exceptions;
- a prohibition against making dividends, distributions and redemptions, subject to permitted exceptions;
- a prohibition against making investments, loans and advances, subject to permitted exceptions;
- restrictions on creating liens and leases on the assets of the Company and its subsidiaries, subject to permitted exceptions;
- restrictions on merging and selling assets outside the ordinary course of business;
- restrictions on use of proceeds, investments, transactions with affiliates or change of principal business;
- a provision limiting oil and natural gas derivative financial instruments;
- a requirement that the Company maintain a ratio of consolidated EBITDAX (as defined in the Second Amended Credit Facility) to consolidated Interest Expense (as defined in the Second Amended Credit Facility) of no less than 2.5 to 1.0 for the four quarters ended on the last day of each quarter; and
- a requirement that the Company maintain a Current Ratio (as defined in the Second Amended Credit Facility) of consolidated current assets (with exclusions as described in the Amended Credit Facility) to

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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.

As of December 31, 2013, the Company had $335.6 million of borrowings and $5.2 million of outstanding letters of credit issued under the Second Amended Credit Facility, resulting in an unused borrowing base capacity of $1,159.2 million. As of December 31, 2013, the weighted average interest rate on borrowings under the Second Amended Credit Facility was 1.8%. Other than indebtedness under the Second Amended Credit Facility that becomes due in April 2018, the Company does not have any debt that matures within the five years ending December 31, 2018. The Company was in compliance with the financial covenants of the Second Amended Credit Facility as of December 31, 2013.

Deferred financing costs. As of December 31, 2013, the Company had $41.8 million of deferred financing costs related to the Notes and the Second Amended Credit Facility. The deferred financing costs are included in deferred costs and other assets on the Company's Consolidated Balance Sheet at December 31, 2013 and are being amortized over the respective terms of the Notes and the Second Amended Credit Facility. Amortization of deferred financing costs recorded for the year ended December 31, 2013, 2012 and 2011 was $4.5 million, $3.0 million and $1.7 million, respectively. These costs are included in interest expense on the Company's Condensed Consolidated Statement of Operations.

10. Asset Retirement Obligations

The following table reflects the changes in the Company's ARO during the years ended December 31, 2013 and 2012:

	Year Ended December 31,	
	2013[(1)]	2012
	(In thousands)	
Asset retirement obligation — beginning of period	$23,234	$13,075
Liabilities incurred during period	11,665	7,585
Liabilities settled during period	—	(71)
Accretion expense during period	1,346	872
Revisions to estimates	213	1,773
Asset retirement obligation — end of period	$36,458	$23,234

(1) Includes ARO for wells acquired in the West Williston Acquisition and the East Nesson Acquisitions (See Note 6 — Acquisitions).

11. Income Taxes

The Company's income tax expense consists of the following:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Current:			
Federal	$475	$—	$—
State	—	7	—
	475	7	—
Deferred:			
Federal	122,853	82,841	42,809
State	11,730	9,638	3,980
	134,583	92,479	46,789
Total income tax expense	$135,058	$92,486	$46,789

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For the years ended December 31, 2013, 2012 and 2011, the Company's effective tax rate differs from the federal statutory rate of 35% primarily due to state income taxes. The reconciliation of income taxes calculated at the U.S. federal tax statutory rate to the Company's effective tax rate for the years ended December 31, 2013, 2012 and 2011, is set forth below:

	Year Ended December 31,					
	2013		2012		2011	
	(%)	(In thousands)	(%)	(In thousands)	(%)	(In thousands)
U.S. federal tax statutory rate	35.00 %	$127,056	35.00 %	$86,056	35.00 %	$44,163
State income taxes, net of federal income tax benefit	2.06 %	7,469	2.47 %	6,068	2.38 %	3,004
Other	0.14 %	533	0.15 %	362	(0.30)%	(378)
Annual effective tax expense	37.20 %	$135,058	37.62 %	$92,486	37.08 %	$46,789

Significant components of the Company's deferred tax assets and liabilities as of December 31, 2013 and 2012, were as follows:

	Year Ended December 31,	
	2013	2012
	(In thousands)	
Deferred tax assets		
Net operating loss carryforward	$17,215	$13,926
Bonus and stock-based compensation	8,060	3,571
Derivative instruments and other	1,664	—
Total deferred tax assets	26,939	17,497
Deferred tax liabilities		
Oil and natural gas properties	343,751	191,271
Derivative instruments	—	8,455
Total deferred tax liabilities	343,751	199,726
Total net deferred tax liability	$316,812	$182,229

The Company generated a federal net operating tax loss of $14.7 million and accrued $0.5 million of current income tax expense for the year ended December 31, 2013. The net operating loss carryforwards consist of $50.9 million of federal net operating loss carryforwards, which expire between 2030 and 2033, and $34.0 million of state net operating loss carryforwards, which expire between 2017 and 2033. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforwards is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. Management believes that the Company's taxable temporary differences and future taxable income will more likely than not be sufficient to utilize substantially all its tax carryforwards prior to their expiration.

Pursuant to authoritative guidance, the Company's $17.2 million deferred tax asset related to net operating loss carryforwards is net of $1.8 million of unrealized excess tax benefits related to excess stock-based compensation on federal and state net operating losses of $4.8 million and $3.5 million, respectively.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2013, the Company had no unrecognized tax benefits. With respect to income taxes, the Company's policy is to account for interest charges as interest expense and any penalties as tax expense in the Consolidated Statement of Operations. The Company files income tax returns in the U.S. federal jurisdiction and in North Dakota, Montana and Texas. The Company’s income tax returns have not been audited by the IRS or any state jurisdiction. Its statute of limitation for the year ended December 31, 2013 will expire in 2017. The Company’s earliest open year in its key jurisdictions is 2010 for both the U.S. federal jurisdiction and various U.S. states.

The current portion of the Company’s net deferred taxes was an asset of $6.3 million at December 31, 2013 and a liability of $4.6 million at December 31, 2012.

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12. Stock-Based Compensation

Restricted stock awards. The Company has granted restricted stock awards to employees and directors under its 2010 Long-Term Incentive Plan, the majority of which vest over a three-year period. The maximum number of shares available for grant under the 2010 Long-Term Incentive Plan is 7,200,000. The fair value of restricted stock grants is based on the value of the Company’s common stock on the date of grant. Compensation expense is recognized ratably over the requisite service period. Beginning January 1, 2013, the Company assumed annual forfeiture rates by employee group ranging from 0% to 11% based on the Company’s forfeiture history for this type of award as adjusted for management’s expectations of forfeitures.

The following table summarizes information related to restricted stock held by the Company’s employees and directors for the periods presented:

	Shares	Weighted Average Grant Date Fair Value per Share
Non-vested shares outstanding December 31, 2011	391,278	$ 25.40
Granted	753,285	29.66
Vested	(396,073)	26.04
Forfeited	(48,066)	31.15
Non-vested shares outstanding December 31, 2012	700,424	29.22
Granted	594,895	38.64
Vested	(160,219)	27.66
Forfeited	(144,628)	28.99
Non-vested shares outstanding December 31, 2013	990,472	$ 28.20

Stock-based compensation expense recorded for restricted stock awards was approximately $10.2 million for each of the years ended December 31, 2013 and 2012 and $3.7 million for the year ended December 31, 2011, and is included in general and administrative expenses on the Company’s Consolidated Statement of Operations. Unrecognized expense as of December 31, 2013 for all outstanding restricted stock awards was $24.8 million and will be recognized over a weighted average period of 2.0 years. The fair value of awards vested for the year ended December 31, 2013 was $6.5 million.

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

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

The following table summarizes information related to PSUs held by the Company’s officers for the periods presented:

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	Initial Unit Awards	Weighted Average Grant Date Fair Value per Unit
Non-vested PSUs at December 31, 2011	—	$—
Granted	155,220	26.22
Vested	—	—
Forfeited	—	—
Non-vested PSUs at December 31, 2012	155,220	26.22
Granted	135,620	42.01
Vested	—	—
Forfeited	(21,540)	32.89
Non-vested PSUs at December 31, 2013	269,300	$33.64

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

The Monte Carlo simulation model uses assumptions regarding random projections and must be repeated numerous times to achieve a probabilistic assessment. The key valuation assumptions for the Monte Carlo model are the forecast period, initial value, risk-free rate, volatility and correlation coefficients. The risk-free rate is the U.S. Treasury rate on the date of grant. The initial value is the average of the volume weighted average prices for the 30 trading days prior to the start of the performance cycle for the Company and each of its peers. Volatility is the standard deviation of the average percentage in stock price over a historical two-year period for the Company and each of its peers. The correlation coefficients are measures of the strength of the linear relationship between and amongst the Company and its peers estimated based on historical stock price data. Beginning January 1, 2013, the Company assumed an annual forfeiture rate of 2.7% based on management's expectations of forfeitures for all PSUs granted.

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

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

Based on these assumptions, the Monte Carlo simulation model resulted in an expected percentage of PSUs earned of 112% and 98% for the 2013 and 2012 grants, respectively. Stock-based compensation expense recorded for these PSUs for the years ended December 31, 2013 and 2012 was $1.8 million and $0.4 million, respectively, and is included in general and administrative expenses on the Consolidated Statement of Operations. No stock-based compensation expense was recorded for the year ended December 31, 2011 related to the PSUs as the Company had not issued PSUs prior to July 2012. Unrecognized expense as of December 31, 2013 for all outstanding PSUs was $6.8 million and will be recognized over a remaining period of 2.9 years.

For the years ended December 31, 2013, 2012 and 2011, the Company had an associated tax benefit of $4.5 million, $4.0 million and $1.4 million, respectively, related to all stock-based compensation.

13. Common Stock

On December 9, 2013, the Company completed a public offering of 7,000,000 shares of its common stock, par value $0.01 per share, at an offering price of $44.94 per share. Net proceeds from the offering were approximately $314.4 million, after deducting underwriting discounts and estimated offering expenses, of which $70,000 is included in common stock and $314.3 million is included in additional paid-in-capital on the Company's Consolidated Balance Sheet as of December 31, 2013. The Company used a portion of these net proceeds to repay $264.4 million of outstanding indebtedness under its Second Amended Credit Facility, and the remaining proceeds were used to fund its exploration, development and acquisition program and for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on July 15, 2011.

14. Earnings Per Share

Basic earnings per share is computed by dividing income available to common stockholders by the weighted average number of shares outstanding for the periods presented. The calculation of diluted earnings per share includes the potential dilutive impact of non-vested restricted shares outstanding during the periods presented, unless their effect is anti-dilutive.

The following is a calculation of the basic and diluted weighted average shares outstanding for the periods presented:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Basic weighted average common shares outstanding	92,867	92,180	92,056
Dilution effect of stock awards at end of period	544	333	185
Diluted weighted average common shares outstanding	93,411	92,513	92,241
Anti-dilutive stock-based compensation awards	634	465	160

15. Business Segment Information

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

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	Exploration and Production (In thousands)	Well Services	Midstream Services	Consolidated
Year Ended December 31, 2013				
Revenues	$1,084,412	$180,686	$29,230	$1,294,328
Inter-segment revenues	—	(128,841)	(23,488)	(152,329)
Total revenues	1,084,412	51,845	5,742	1,141,999
Operating income	486,697	14,305	3,396	504,398
Other income (expense)	(141,397)	16	—	(141,381)
Income before income taxes	345,300	14,321	3,396	363,017
Total assets[1]	4,532,264	70,708	108,952	4,711,924
Capital expenditures[2]	2,472,126	15,217	18,955	2,506,298
Depreciation, depletion and amortization	304,389	2,091	575	307,055
Year Ended December 31, 2012				
Revenues	$670,491	$82,481	$—	$752,972
Inter-segment revenues	—	(66,304)	—	(66,304)
Total revenues	670,491	16,177	—	686,668
Operating income	276,740	253	—	276,993
Other income (expense)	(31,120)	1	—	(31,119)
Income before income taxes	245,620	254	—	245,874
Total assets	2,475,820	52,974	—	2,528,794
Capital expenditures[2]	1,132,894	15,679	—	1,148,573
Depreciation, depletion and amortization	206,127	607	—	206,734

(1) Total assets for the exploration and production segment includes $137.1 million of assets held for sale as of December 31, 2013.

(2) Capital expenditures reflected in the table above differ from the amounts shown in the Consolidated Statement of Cash Flows 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 Consolidated Statement of Cash Flows are presented on a cash basis.

16. Significant Concentrations

Major customers. For the years ended December 31, 2013 and 2012, sales to Musket Corporation accounted for approximately 11% and 10% of our total sales, respectively. For the year ended December 31, 2011, sales to Texon L.P., Plains All American Pipeline, L.P. and Enserco Energy Inc. accounted for approximately 18%, 16% and 15%, respectively, of our total sales. No other purchasers accounted for more than 10% of the Company’s total sales for the years ended December 31, 2013, 2012 and 2011. Total sales include revenues from the Company’s exploration and production segment only, as OWS and OMS provide services to OPNA.

Substantially all of the Company’s accounts receivable result from sales of oil and natural gas as well as joint interest billings (“JIB”) to third-party companies who have working interest payment obligations in projects completed by the Company. Statoil Oil & Gas L.P. and Continental Resources Inc. accounted for approximately 15% and 10%, respectively, of the Company’s JIB receivables balance at December 31, 2013. No third-party company accounted for more than 10% of the Company’s total JIB receivables balance at December 31, 2012.

This concentration of customers and joint interest owners may impact the Company’s overall credit risk, either positively or negatively, in that these entities may be similarly affected by changes in economic or other conditions. Management believes that the loss of any of these purchasers would not have a material adverse effect on the Company’s operations, as there are a number of alternative oil and natural gas purchasers in the Company’s producing regions.

17. Commitments and Contingencies

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Lease obligations. The Company has operating leases for office space and other property and equipment. The Company incurred rental expense of $1.6 million, $1.5 million and $0.8 million for the years ended December 31, 2013, 2012 and 2011, respectively.
Future minimum annual rental commitments under non-cancelable leases at December 31, 2013 are as follows:

	(In thousands)
2014	$2,927
2015	2,957
2016	2,992
2017	2,235
2018	—
Thereafter	—
	$11,111

Drilling contracts. As of December 31, 2013, the Company had certain drilling rig contracts with initial terms greater than one year. In the event of early contract termination under these contracts, the Company would be obligated to pay approximately $26.2 million as of December 31, 2013 for the days remaining through the end of the primary terms of the contracts.
Volume commitment agreements. As of December 31, 2013, the Company had certain agreements with an aggregate requirement to deliver a minimum quantity of 11.6 MMBbl and 11.8 Bcf from its Williston Basin project areas within specified timeframes, all of which are less than six years. Future obligations under these agreements are $49.3 million as of December 31, 2013.
Purchase agreements. As of December 31, 2013, the Company had certain agreements for the purchase of freshwater with an aggregate future obligation of approximately $5.0 million.
Cost sharing agreements. As of December 31, 2013, the Company had certain agreements to share the cost to construct and install electrical facilities. The Company’s estimated future obligation under these agreements was $12.7 million as of December 31, 2013.

Investment commitment. As of December 31, 2013, the Company had a remaining capital commitment to invest, expend and/or incur expenses of $7.0 million in connection with drilling and completion activities for certain wells located in its East Nesson project area, in exchange for the transfer of assets in connection with the East Nesson Acquisitions.
Litigation. The Company is party to various legal and/or regulatory proceedings from time to time arising in the ordinary course of business. The Company believes all such matters are without merit or involve amounts which, if resolved unfavorably, either individually or in the aggregate, will not have a material adverse effect on its financial condition, results of operations or cash flows.
18. Subsequent Events

Divestiture. In January 2014, the Company executed a purchase and sale agreement for the sale of certain non-operated properties in its Sanish project area and other non-operated leases adjacent to its Sanish position for approximately $333.0 million, subject to customary post-close adjustments. The sale is expected to close during the first quarter of 2014.

Derivative instruments. In February 2014, the Company entered into new swap agreements for a total notional amounts of 1,100,000 barrels, 1,516,000 barrels and 62,000 barrels, which settle in 2014, 2015 and 2016, respectively, based on the WTI crude oil index price. These derivative instruments do not qualify for and were not designated as hedging instruments for accounting purposes.

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19. Condensed Consolidating Financial Statements

The Notes (see Note 9 — Long-Term Debt) are guaranteed on a senior unsecured basis by the Guarantors, which are 100% owned by the Company. These guarantees are full and unconditional and joint and several among the Guarantors. Certain of the Company's immaterial wholly owned subsidiaries do not guarantee the Notes ("Non-Guarantor Subsidiaries").

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

Condensed Consolidating Balance Sheet

(In thousands, except share data)

	December 31, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$34,277	$57,624	$—	$91,901
Accounts receivable – oil and gas revenues	—	175,653	—	175,653
Accounts receivable – joint interest partners	—	139,459	—	139,459
Accounts receivable – affiliates	770	9,100	(9,870)	—
Inventory	—	20,652	—	20,652
Prepaid expenses	318	9,873	—	10,191
Advances to joint interest partners	—	760	—	760
Derivative instruments	—	2,264	—	2,264
Deferred income taxes	—	6,335	—	6,335
Other current assets	—	391	—	391
Total current assets	35,365	422,111	(9,870)	447,606
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	4,528,958	—	4,528,958
Other property and equipment	—	188,468	—	188,468
Less: accumulated depreciation, depletion, amortization and impairment	—	(637,676)	—	(637,676)
Total property, plant and equipment, net	—	4,079,750	—	4,079,750
Assets held for sale	—	137,066	—	137,066
Investments in and advances to subsidiaries	3,450,668	—	(3,450,668)	—
Derivative instruments	—	1,333	—	1,333
Deferred income taxes	85,288	—	(85,288)	—
Deferred costs and other assets	33,983	12,186	—	46,169
Total assets	$3,605,304	$4,652,446	$(3,545,826)	$4,711,924
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable	$—	$8,920	$—	$8,920
Accounts payable – affiliates	9,100	770	(9,870)	—

Advances from joint interest partners	—	12,829	—	12,829

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Revenues and production taxes payable	—	146,741	—	146,741
Accrued liabilities	33	241,797	—	241,830
Accrued interest payable	47,622	288	—	47,910
Derivative instruments	—	8,188	—	8,188
Total current liabilities	56,755	419,533	(9,870)	466,418
Long-term debt	2,200,000	335,570	—	2,535,570
Asset retirement obligations	—	35,918	—	35,918
Derivative instruments	—	139	—	139
Deferred income taxes	—	408,435	(85,288)	323,147
Other liabilities	—	2,183	—	2,183
Total liabilities	2,256,755	1,201,778	(95,158)	3,363,375
Stockholders' equity				
Capital contributions from affiliates	—	2,930,978	(2,930,978)	—
Common stock, $0.01 par value; 300,000,000 shares authorized; 100,866,589 shares issued	996	—	—	996
Treasury stock, at cost; 167,155 shares	(5,362)	—	—	(5,362)
Additional paid-in-capital	985,023	8,743	(8,743)	985,023
Retained earnings	367,892	510,947	(510,947)	367,892
Total stockholders' equity	1,348,549	3,450,668	(3,450,668)	1,348,549
Total liabilities and stockholders' equity	$3,605,304	$4,652,446	$(3,545,826)	$4,711,924

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

	December 31, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
ASSETS				
Current assets				
Cash and cash equivalents	$133,797	$79,650	$—	$213,447
Short-term investments	25,891	—	—	25,891
Accounts receivable – oil and gas revenues	—	110,341	—	110,341
Accounts receivable – joint interest partners	—	99,194	—	99,194
Accounts receivable – affiliates	310	5,845	(6,155)	—
Inventory	—	20,707	—	20,707
Prepaid expenses	313	1,457	—	1,770
Advances to joint interest partners	—	1,985	—	1,985
Derivative instruments	—	19,016	—	19,016
Other current assets	235	100	—	335
Total current assets	160,546	338,295	(6,155)	492,686
Property, plant and equipment				
Oil and gas properties (successful efforts method)	—	2,348,128	—	2,348,128
Other property and equipment	—	49,732	—	49,732
Less: accumulated depreciation, depletion, amortization and impairment	—	(391,260)	—	(391,260)
Total property, plant and equipment, net	—	2,006,600	—	2,006,600
Investments in and advances to subsidiaries	1,807,010	—	(1,807,010)	—

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Derivative instruments	—	4,981	—	4,981
Deferred income taxes	42,746	—	(42,746)	—
Deferred costs and other assets	20,748	3,779	—	24,527
Total assets	$2,031,050	$2,353,655	$(1,855,911)	$2,528,794
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities				
Accounts payable	$9	$12,482	$—	$12,491
Accounts payable - affiliates	5,845	310	(6,155)	—
Advances from joint interest partners	—	21,176	—	21,176
Revenues and production taxes payable	—	71,553	—	71,553
Accrued liabilities	100	189,763	—	189,863
Accrued interest payable	30,091	5	—	30,096
Derivative instruments	—	1,048	—	1,048
Deferred income taxes	—	4,558	—	4,558
Total current liabilities	36,045	300,895	(6,155)	330,785
Long-term debt	1,200,000	—	—	1,200,000
Asset retirement obligations	—	22,956	—	22,956
Derivative instruments	—	380	—	380
Deferred income taxes	—	220,417	(42,746)	177,671
Other liabilities	—	1,997	—	1,997
Total liabilities	1,236,045	546,645	(48,901)	1,733,789
Stockholders' equity				
Capital contributions from affiliates	—	1,586,780	(1,586,780)	—
Common stock, $0.01 par value; 300,000,000 shares authorized; 93,432,712 issued	925	—	—	925
Treasury stock, at cost; 129,414 shares	(3,796)	—	—	(3,796)
Additional paid-in-capital	657,943	8,743	(8,743)	657,943
Retained earnings	139,933	211,487	(211,487)	139,933
Total stockholders' equity	795,005	1,807,010	(1,807,010)	795,005
Total liabilities and stockholders' equity	$2,031,050	$2,353,655	$(1,855,911)	$2,528,794

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Condensed Consolidating Statement of Operations
(In thousands)

	Year Ended December 31, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$1,084,412	$—	$1,084,412
Well services and midstream revenues	—	57,587	—	57,587
Total revenues	—	1,141,999	—	1,141,999
Expenses				
Lease operating expenses	—	94,634	—	94,634
Well services and midstream operating expenses	—	30,713	—	30,713
Marketing, transportation and gathering expenses	—	25,924	—	25,924
Production taxes	—	100,537	—	100,537
Depreciation, depletion and amortization	—	307,055	—	307,055
Exploration expenses	—	2,260	—	2,260
Impairment of oil and gas properties	—	1,168	—	1,168
General and administrative expenses	14,044	61,266	—	75,310
Total expenses	14,044	623,557	—	637,601
Operating income (loss)	(14,044)	518,442	—	504,398
Other income (expense)				
Equity in earnings of subsidiaries	299,459	—	(299,459)	—
Net loss on derivative instruments	—	(35,432)	—	(35,432)
Interest expense, net of capitalized interest	(99,663)	(7,502)	—	(107,165)
Other income (expense)	(335)	1,551	—	1,216
Total other income (expense)	199,461	(41,383)	(299,459)	(141,381)
Income before income taxes	185,417	477,059	(299,459)	363,017
Income tax benefit (expense)	42,542	(177,600)	—	(135,058)
Net income	$227,959	$299,459	$(299,459)	$227,959

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Condensed Consolidating Statement of Operations
(In thousands)

	Year Ended December 31, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Revenues				
Oil and gas revenues	$—	$670,491	$—	$670,491
Well services revenues	—	16,177	—	16,177
Total revenues	—	686,668	—	686,668
Expenses				
Lease operating expenses	—	54,924	—	54,924
Well services operating expenses	—	11,774	—	11,774
Marketing, transportation and gathering expenses	—	9,257	—	9,257
Production taxes	—	62,965	—	62,965
Depreciation, depletion and amortization	—	206,734	—	206,734
Exploration expenses	—	3,250	—	3,250
Impairment of oil and gas properties	—	3,581	—	3,581
General and administrative expenses	12,591	44,599	—	57,190
Total expenses	12,591	397,084	—	409,675
Operating income (loss)	(12,591)	289,584	—	276,993
Other income (expense)				
Equity in earnings of subsidiaries	202,924	—	(202,924)	—
Net gain on derivative instruments	—	34,164	—	34,164
Interest expense, net of capitalized interest	(67,651)	(2,492)	—	(70,143)
Other income (expense)	1,118	3,742	—	4,860
Total other income (expense)	136,391	35,414	(202,924)	(31,119)
Income before income taxes	123,800	324,998	(202,924)	245,874
Income tax benefit (expense)	29,588	(122,074)	—	(92,486)
Net income	$153,388	$202,924	$(202,924)	$153,388

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Condensed Consolidating Statement of Operations
(In thousands)

	Year Ended December 31, 2011			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Oil and gas revenues	$—	$330,422	$—	$330,422
Expenses				
Lease operating expenses	—	32,707	—	32,707
Marketing, transportation and gathering expenses	—	1,365	—	1,365
Production taxes	—	33,865	—	33,865
Depreciation, depletion and amortization	—	74,981	—	74,981
Exploration expenses	—	1,685	—	1,685
Impairment of oil and gas properties	—	3,610	—	3,610
Loss on sale of properties	—	207	—	207
General and administrative expenses	5,505	23,930	—	29,435
Total expenses	5,505	172,350	—	177,855
Operating income (loss)	(5,505)	158,072	—	152,567
Other income (expense)				
Equity in earnings of subsidiaries	99,836	—	(99,836)	—
Net gain on derivative instruments	—	1,595	—	1,595
Interest expense, net of capitalized interest	(28,310)	(1,308)	—	(29,618)
Other income (expense)	1,165	470	—	1,635
Total other income (expense)	72,691	757	(99,836)	(26,388)
Income before income taxes	67,186	158,829	(99,836)	126,179
Income tax benefit (expense)	12,204	(58,993)	—	(46,789)
Net income	$79,390	$99,836	$(99,836)	$79,390

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Condensed Consolidating Statement of Cash Flows
(In thousands)

	Year Ended December 31, 2013			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$227,959	$299,459	$(299,459)	$227,959
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(299,459)	—	299,459	—
Depreciation, depletion and amortization	—	307,055	—	307,055
Impairment of oil and gas properties	—	1,168	—	1,168
Deferred income taxes	(42,542)	177,125	—	134,583
Derivative instruments	—	35,432	—	35,432
Stock-based compensation expenses	11,602	380	—	11,982
Debt discount amortization and other	4,018	230	—	4,248
Working capital and other changes:				
Change in accounts receivable	(460)	(110,266)	3,253	(107,473)
Change in inventory	—	(13,941)	—	(13,941)
Change in prepaid expenses	(5)	(8,186)	—	(8,191)
Change in other current assets	235	(291)	—	(56)
Change in other assets	—	(3,248)	—	(3,248)
Change in accounts payable and accrued liabilities	20,710	89,994	(3,253)	107,451
Change in other liabilities	—	887	—	887
Net cash provided by (used in) operating activities	(77,942)	775,798	—	697,856
Cash flows from investing activities:				
Capital expenditures	—	(893,524)	—	(893,524)
Acquisition of oil and gas properties	—	(1,560,072)	—	(1,560,072)
Derivative settlements	—	(8,133)	—	(8,133)
Redemptions of short-term investments	25,000	—	—	25,000
Advances from joint interest partners	—	(8,347)	—	(8,347)
Net cash provided by (used in) investing activities	25,000	(2,470,076)	—	(2,445,076)
Cash flows from financing activities:				
Proceeds from issuance of senior notes	1,000,000	—	—	1,000,000
Proceeds from revolving credit facility	—	600,000	—	600,000
Principal payments on revolving credit facility	—	(264,430)	—	(264,430)
Debt issuance costs	(16,362)	(6,548)	—	(22,910)
Proceeds from sale of common stock	314,580	—	—	314,580
Purchases of treasury stock	(1,566)	—	—	(1,566)
Investment in / capital contributions from subsidiaries	(1,343,230)	1,343,230	—	—
Net cash provided by (used in) financing activities	(46,578)	1,672,252	—	1,625,674
Decrease in cash and cash equivalents	(99,520)	(22,026)	—	(121,546)
Cash and cash equivalents at beginning of period	133,797	79,650	—	213,447
Cash and cash equivalents at end of period	$34,277	$57,624	$—	$91,901

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Condensed Consolidating Statement of Cash Flows
(In thousands)

	Year Ended December 31, 2012			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$153,388	$202,924	$(202,924)	$153,388
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(202,924)	—	202,924	—
Depreciation, depletion and amortization	—	206,734	—	206,734
Impairment of oil and gas properties	—	3,581	—	3,581
Deferred income taxes	(29,588)	122,067	—	92,479
Derivative instruments	—	(34,164)	—	(34,164)
Stock-based compensation expenses	10,219	114	—	10,333
Debt discount amortization and other	2,277	533	—	2,810
Working capital and other changes:				
Change in accounts receivable	(222)	(94,106)	4,225	(90,103)
Change in inventory	—	(29,313)	—	(29,313)
Change in prepaid expenses	(4)	350	—	346
Change in other current assets	(217)	373	—	156
Change in other assets	25	(120)	—	(95)
Change in accounts payable and accrued liabilities	18,612	62,319	(4,225)	76,706
Change in other current liabilities	—	(472)	—	(472)
Net cash provided by (used in) operating activities	(48,434)	440,820	—	392,386
Cash flows from investing activities:				
Capital expenditures	—	(1,051,365)	—	(1,051,365)
Derivative settlements	—	6,545	—	6,545
Purchases of short-term investments	(126,213)	—	—	(126,213)
Redemptions of short-term investments	120,316	—	—	120,316
Advances from joint interest partners	—	12,112	—	12,112
Net cash used in investing activities	(5,897)	(1,032,708)	—	(1,038,605)
Cash flows from financing activities:				
Proceeds from issuance of senior notes	400,000	—	—	400,000
Debt issuance costs	(7,307)	(705)	—	(8,012)
Purchases of treasury stock	(3,194)	—	—	(3,194)
Investment in / capital contributions from subsidiaries	(644,853)	644,853	—	—
Net cash provided by (used in) financing activities	(255,354)	644,148	—	388,794
Increase (decrease) in cash and cash equivalents	(309,685)	52,260	—	(257,425)
Cash and cash equivalents at beginning of period	443,482	27,390	—	470,872
Cash and cash equivalents at end of period	$133,797	$79,650	$—	$213,447

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Condensed Consolidating Statement of Cash Flows
(In thousands)

	Year Ended December 31, 2011			
	Parent/ Issuer	Combined Guarantor Subsidiaries	Intercompany Eliminations	Consolidated
Cash flows from operating activities:				
Net income	$79,390	$99,836	$(99,836)	$79,390
Adjustments to reconcile net income to net cash provided by (used in) operating activities:				
Equity in earnings of subsidiaries	(99,836)	—	99,836	—
Depreciation, depletion and amortization	—	74,981	—	74,981
Impairment of oil and gas properties	—	3,610	—	3,610
Loss on sale of properties	—	207	—	207
Deferred income taxes	(12,204)	58,993	—	46,789
Derivative instruments	—	(1,595)	—	(1,595)
Stock-based compensation expenses	3,656	—	—	3,656
Debt discount amortization and other	1,196	365	—	1,561
Working capital and other changes:				
Change in accounts receivable	(88)	(66,134)	1,322	(64,900)
Change in inventory	—	(2,550)	—	(2,550)
Change in prepaid expenses	(73)	(1,527)	—	(1,600)
Change in other current assets	(18)	(473)	—	(491)
Change in other assets	(100)	(39)	—	(139)
Change in accounts payable and accrued liabilities	17,127	20,511	(1,322)	36,316
Change in other current liabilities	—	472	—	472
Change in other liabilities	—	317	—	317
Net cash provided by (used in) operating activities	(10,950)	186,974	—	176,024
Cash flows from investing activities:				
Capital expenditures	—	(613,720)	—	(613,720)
Derivative settlements	—	(3,841)	—	(3,841)
Purchases of short-term investments	(184,907)	—	—	(184,907)
Redemptions of short-term investments	164,913	—	—	164,913
Advances from joint interest partners	—	5,963	—	5,963
Proceeds from equipment and property sales	—	2,202	—	2,202
Net cash used in investing activities	(19,994)	(609,396)	—	(629,390)
Cash flows from financing activities:				
Proceeds from issuance of senior notes	800,000	—	—	800,000
Debt issuance costs	(16,838)	(1,842)	—	(18,680)
Purchases of treasury stock	(602)	—	—	(602)
Investment in / capital contributions from subsidiaries	(428,074)	428,074	—	—
Net cash provided by financing activities	354,486	426,232	—	780,718
Increase in cash and cash equivalents	323,542	3,810	—	327,352
Cash and cash equivalents at beginning of period	119,940	23,580	—	143,520
Cash and cash equivalents at end of period	$443,482	$27,390	$—	$470,872

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20. Supplemental Oil and Gas Disclosures

The supplemental data presented below reflects information for all of the Company's oil and natural gas producing activities.

Capitalized Costs

The following table sets forth the capitalized costs related to the Company's oil and natural gas producing activities at December 31, 2013 and 2012:

	December 31,	
	2013(1)	2012
	(In thousands)	
Proved oil and gas properties(2)	$3,713,525	$2,271,711
Less: Accumulated depreciation, depletion, amortization and impairment	(612,380)	(383,564)
Proved oil and gas properties, net	3,101,145	1,888,147
Unproved oil and gas properties	815,433	76,417
Total oil and gas properties, net	$3,916,578	$1,964,564

(1) At December 31, 2013, oil and gas properties exclude capitalized costs related to certain assets in and around the Company's Sanish project area, which were held for sale.

(2) Included in the Company's proved oil and gas properties are estimates of future asset retirement costs of $32.6 million and $20.7 million at December 31, 2013 and 2012, respectively.

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development Activities

The following table sets forth costs incurred related to the Company's oil and natural gas activities for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Acquisition costs:			
Proved oil and gas properties	$752,454	$3,159	$3,356
Unproved oil and gas properties	837,419	34,098	15,197
Exploration costs	2,260	3,250	1,685
Development costs	890,267	1,074,441	618,737
Asset retirement costs	11,856	9,359	5,055
Total costs incurred	$2,494,256	$1,124,307	$644,030

Results of Operations for Oil and Natural Gas Producing Activities

Results of operations for oil and natural gas producing activities, which excludes straight-line depreciation, general and administrative expenses and interest expense, are presented below.

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	Year Ended December 31,		
	2013	2012	2011
	(In thousands)		
Revenues	$1,084,412	$670,491	$330,422
Production costs	221,095	127,146	67,937
Depreciation, depletion and amortization	298,999	202,398	74,101
Exploration costs	2,260	3,250	1,685
Impairment of oil and gas properties	1,168	3,581	3,610
Loss on sale of properties	—	—	207
Income tax expense	196,312	116,941	64,009
Results of operations for oil and natural gas producing activities	$364,578	$217,175	$118,873

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21. Supplemental Oil and Gas Reserve Information — Unaudited

The reserve estimates at December 31, 2013, 2012 and 2011 presented in the table below are based on reports prepared by DeGolyer and MacNaughton, the Company's independent reserve engineers, in accordance with the FASB's authoritative guidance on oil and gas reserve estimation and disclosures. At December 31, 2013, 2012 and 2011, all of the Company's oil and natural gas producing activities were conducted within the continental United States.

The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries and undeveloped locations are more imprecise than estimates of established proved producing oil and natural gas properties. Accordingly, these estimates are expected to change as future information becomes available.

Proved oil and natural gas reserves are the estimated quantities of oil and natural gas which geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions (i.e., prices and costs) existing at the time the estimate is made. Proved developed oil and natural gas reserves are proved reserves that can be expected to be recovered through existing wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Estimated Quantities of Proved Oil and Natural Gas Reserves — Unaudited

The following table sets forth the Company's estimated net proved, proved developed and proved undeveloped reserves at December 31, 2013, 2012 and 2011:

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	Oil (MBbl)	Gas (MMcf)	MBoe
2011			
Proved reserves			
Beginning balance	36,550	19,379	39,780
Revisions of previous estimates	(262)	(159)	(288)
Extensions, discoveries and other additions	36,464	40,220	43,168
Sales of reserves in place	(56)	(518)	(142)
Purchases of reserves in place	100	65	111
Production	(3,732)	(1,087)	(3,914)
Net proved reserves at December 31, 2011	69,064	57,900	78,715
Proved developed reserves, December 31, 2011	31,749	24,535	35,839
Proved undeveloped reserves, December 31, 2011	37,315	33,365	42,876
2012			
Proved reserves			
Beginning balance	69,064	57,900	78,715
Revisions of previous estimates	(567)	(8,495)	(1,983)
Extensions, discoveries and other additions	66,245	45,759	73,871
Sales of reserves in place	—	—	—
Purchases of reserves in place	881	512	966
Production	(7,533)	(4,146)	(8,224)
Net proved reserves at December 31, 2012	128,090	91,530	143,345
Proved developed reserves, December 31, 2012	62,602	44,695	70,051
Proved undeveloped reserves, December 31, 2012	65,488	46,835	73,294
2013			
Proved reserves			
Beginning balance	128,090	91,530	143,345
Revisions of previous estimates	3,390	10,411	5,125
Extensions, discoveries and other additions	40,784	31,856	46,094
Sales of reserves in place	—	—	—
Purchases of reserves in place	37,459	49,631	45,731
Production	(11,133)	(7,450)	(12,375)
Net proved reserves at December 31, 2013	198,590	175,979	227,920
Proved developed reserves, December 31, 2013	106,774	92,170	122,136
Proved undeveloped reserves, December 31, 2013	91,816	83,809	105,784

Purchases of Reserves in Place

In 2013, the Company purchased 45,731 MBoe of estimated net proved reserves from properties acquired in the West Williston Acquisition and the East Nesson Acquisitions. In 2012, the Company purchased 966 MBoe of estimated net proved reserves from properties acquired in Burke and Mountrail counties. The Company had no significant reserve purchases in 2011.

Extensions, Discoveries and Other Additions

In 2013, the Company had a total of 46,094 MBoe of additions due to extensions and discoveries. An estimated 22,190 MBoe of these extensions and discoveries were associated with new producing wells at December 31, 2013, with 100% of these reserves from wells producing in the Bakken or Three Forks formations. An additional 23,904 MBoe of proved undeveloped reserves were added across all three of the Company’s Williston Basin project areas associated with the Company’s 2013 operated and non-operated drilling program, with 100% of these proved undeveloped reserves in the Bakken or Three Forks formations.

In 2012, the Company had a total of 73,871 MBoe of additions due to extensions and discoveries. An estimated 16,548 MBoe of these extensions and discoveries were associated with new producing wells at December 31, 2012, with 100% of these reserves from wells producing in the Bakken or Three Forks formations. An additional 57,323 MBoe of proved undeveloped reserves were added across all three of the Company's Williston Basin project areas associated with the Company's 2012 operated and non-operated drilling program, with 100% of these proved undeveloped reserves in the Bakken or Three Forks formations.

In 2011, the Company had a total of 43,168 MBoe of additions. An estimated 12,696 MBoe of extensions and discoveries were associated with new producing wells at December 31, 2011, with 100% of these reserves from wells producing in the Bakken or Three Forks formations. An additional 30,472 MBoe of proved undeveloped reserves were added across all three of the Company's Williston Basin project areas associated with the Company's 2011 operated and non-operated drilling program, with 100% of these proved undeveloped reserves in the Bakken or Three Forks formations.

Sales of Reserves in Place

In 2013 and 2012, the Company did not have any sales of reserves. In November 2011, the Company sold its remaining interests in non-core oil and gas producing properties located in the Barnett shale in Texas, which had a minimal impact on the Company's estimated net proved reserves.

Revisions of Previous Estimates

In 2013, the Company had a net positive revision of 5,125 MBoe, or 3.6% of the beginning of the year estimated net proved reserves balance. This net positive revision was the result of several immaterial changes, including well performances, working interests, operating costs and realized prices.

In 2012, the Company had a net negative revision of 1,983 MBoe, or 2.5% of the beginning of the year estimated net proved reserves balance. The primary causes for this revision were negative well performances offset by working interest increases in the proved locations. Actual well results in portions of the Company's acreage came in below the proved forecasts prepared in 2011. The proved forecasts for the 2012 reserve report have been adjusted to reflect these well performances. The working interest increases arose from acreage trades, non-participation by other interest owners and additional mineral leasing in the reserve locations. Operating costs and realized prices had an immaterial impact to the reserves balance.

In 2011, the Company had a net negative revision of 288 MBoe, or 0.7% of the beginning of the year estimated net proved reserves balance. This net negative revision was the result of several immaterial changes, including well performances, net revenue interest changes, operating costs and realized prices.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Natural Gas Reserves — Unaudited

The Standardized Measure represents the present value of estimated future net cash flows from estimated net proved oil and natural gas reserves, less future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect timing of future cash flows. Production costs do not include depreciation, depletion and amortization of capitalized acquisition, exploration and development costs.

The Company's estimated net proved reserves and related future net revenues 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 $96.96/Bbl for oil and $3.66/MMBtu for natural gas for the year ended December 31, 2013, $94.68/Bbl for oil and $2.75/MMBtu for natural gas for the year ended December 31, 2012 and $96.23/Bbl for oil and $4.12/MMBtu for natural gas for the year ended December 31, 2011. 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 following table sets forth the Standardized Measure of discounted future net cash flows from projected production of the Company's estimated net proved reserves at December 31, 2013, 2012 and 2011.

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	At December 31, 2013	2012	2011
	(In thousands)		
Future cash inflows	$19,063,500	$11,321,992	$6,508,604
Future production costs	(5,473,767)	(2,809,960)	(1,690,264)
Future development costs	(1,904,095)	(1,434,648)	(783,486)
Future income tax expense	(3,628,977)	(2,123,973)	(1,225,395)
Future net cash flows	8,056,661	4,953,411	2,809,459
10% annual discount for estimated timing of cash flows	(4,329,102)	(2,693,514)	(1,489,988)
Standardized measure of discounted future net cash flows	$3,727,559	$2,259,897	$1,319,471

The following table sets forth the changes in the Standardized Measure of discounted future net cash flows applicable to estimated net proved reserves for the periods presented.

	2013	2012	2011
	(In thousands)		
January 1,	$2,259,897	$1,319,471	$485,735
Net changes in prices and production costs	254,979	(7,814)	299,108
Net changes in future development costs	57,566	28,124	(38,244)
Sales of oil and natural gas, net	(857,540)	(542,515)	(262,485)
Extensions	1,111,202	1,358,479	989,697
Discoveries	—	—	—
Purchases of reserves in place	858,382	15,890	2,679
Sales of reserves in place	—	—	(2,499)
Revisions of previous quantity estimates	99,954	(47,957)	(5,058)
Previously estimated development costs incurred	373,912	480,925	146,847
Accretion of discount	346,068	190,370	69,782
Net change in income taxes	(774,910)	(400,196)	(372,146)
Changes in timing and other	(1,951)	(134,880)	6,055
December 31,	$3,727,559	$2,259,897	$1,319,471

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22. Quarterly Financial Data — Unaudited

The Company's results of operations by quarter for the years ended December 31, 2013 and 2012 are as follows:

	For the Year Ended December 31, 2013			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$248,304	$254,582	$305,498	$333,615
Operating income	117,953	113,450	150,862	122,133
Net income	51,851	67,119	54,499	54,490

	For the Year Ended December 31, 2012			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands)			
Revenues	$138,566	$149,063	$184,710	$214,327
Operating income	58,152	60,184	72,038	86,619
Net income	16,442	76,041	18,314	42,591

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our Chief Executive Officer ("CEO"), our principal executive officer; Chief Financial Officer ("CFO"), our principal financial officer; and Chief Accounting Officer ("CAO"), the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2013. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our CEO, CFO and CAO as appropriate, to allow timely decisions regarding required disclosure. Based on the evaluation, our CEO, CFO and CAO have concluded that our disclosure controls and procedures were effective at December 31, 2013 at the reasonable assurance level.

Management's report on internal control over financial reporting. Management, including our CEO, CFO and CAO, is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act). Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2013, management assessed the effectiveness of our internal control over financial reporting. In making this assessment, management, including our CEO, CFO and CAO, used the criteria set forth by the Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this assessment, management concluded that our internal control over financial reporting was effective as of December 31, 2013.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited our consolidated financial statements included in this annual report on Form 10-K, has also audited the effectiveness of our internal control over financial reporting at December 31, 2013. Their "Report of Independent Registered Public Accounting

Firm," which expresses

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an unqualified opinion on the effectiveness of our internal control over financial reporting at December 31, 2013, is included in Item 8.

Changes in internal control over financial reporting. There were no changes in our internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2014 Annual Meeting of Stockholders.

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PART IV

Item 15. Exhibits, Financial Statement Schedules

a. The following documents are filed as a part of this Annual Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit No.	Description of Exhibit
3.1	Amended and Restated Certificate of Incorporation of Oasis Petroleum Inc. (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
3.2	Amended and Restated Bylaws of Oasis Petroleum Inc. (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
4.2	Registration Rights Agreement dated as of September 24, 2013 among the Company, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 25, 2013, and incorporated herein by reference).
4.3	Indenture dated as of February 2, 2011 among the Company and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
4.4	First Supplemental Indenture dated as of February 2, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on February 2, 2011, and incorporated herein by reference).
4.5	Second Supplemental Indenture dated as of September 19, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.4 to the Company's Registration Statement on Form S-4 on September 23, 2011, and incorporated herein by reference).
4.6	Indenture dated as of November 10, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on November 10, 2011, and incorporated herein by reference).
4.7	First Supplemental Indenture dated as of November 10, 2011 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on November 10, 2011, and incorporated herein by reference).
4.8	Second Supplemental Indenture dated as of July 2, 2012 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on July 2, 2012, and incorporated herein by reference).

4.9	Third Supplemental Indenture (to the Indenture dated as of February 2, 2011) dated as of June 18, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Quarterly Report on Form 10-Q on August 7, 2013, and incorporated herein by reference).
4.10	Third Supplemental Indenture (to the Indenture dated as of November 10, 2011) dated as of June 18, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.2 to the Company's Quarterly Report on Form 10-Q on August 7, 2013, and incorporated herein by reference).
4.11	Fourth Supplemental Indenture dated as of September 24, 2013 among the Company, the Guarantors and U.S. Bank National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K filed on September 25, 2013, and incorporated herein by reference).

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Exhibit No.	Description of Exhibit
10.1	Business Opportunities Agreement dated as of June 22, 2010 by and among Oasis Petroleum Inc., EnCap Investments L.P., Douglas E. Swanson, Jr. and Robert L. Zorich (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on June 24, 2010, and incorporated herein by reference).
10.2	Second Amended and Restated Credit Agreement, dated as of April 5, 2013, among Oasis Petroleum Inc., as parent, Oasis Petroleum North America LLC, as borrower, the other credit parties party thereto, Wells Fargo Bank, N.A., as administrative agent and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 9, 2013, and incorporated herein by reference).
10.3	First Amendment to Second Amended and Restated Credit Agreement dated as of September 3, 2013 among Oasis Petroleum Inc., as Parent, Oasis Petroleum North America LLC, as Borrower, the Other Credit Parties thereto, Wells Fargo Bank, N.A., as Administrative Agent and the Lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 5, 2013, and incorporated herein by reference).
10.4**	Long-Term Incentive Plan of Oasis Petroleum Inc. (filed as Exhibit 10.6 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.5(a)**	Form of Indemnification Agreement between Oasis Petroleum Inc. and each of the directors and executive officers thereof.
10.6**	2010 Annual Incentive Compensation Plan of Oasis Petroleum Inc. (filed as Exhibit 10.9 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.7**	Form of Notice of Grant of Restricted Stock (filed as Exhibit 10.10 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.8**	Form of Restricted Stock Agreement (filed as Exhibit 10.11 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.9**	Form of Notice of Grant of Restricted Stock Unit (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.10**	Form of Notice of Grant of Restricted Stock Unit Designated as a Performance Share Unit (filed as Exhibit 10.13 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.11**	Form of Restricted Stock Unit Agreement (filed as Exhibit 10.14 to the Company's Registration Statement on Form S-1/A on May 19, 2010, and incorporated herein by reference).
10.12**	Form of Notice of Grant of Performance Share Units (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on August 3, 2012, and incorporated herein by reference).
10.13**	Form of Performance Share Unit Agreement (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on August 3, 2012, and incorporated herein by reference).
10.14**	

	April 20, 2012 Resignation, Consent and Appointment Agreement and Amendment Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 23, 2012, and incorporated herein by reference).
10.15**	Amended and Restated Employment Agreement dated as of March 1, 2012 between Oasis Petroleum Inc. and Thomas B. Nusz (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 2, 2012, and incorporated herein by reference).
10.16**	Employment Agreement dated as of March 1, 2012 between Oasis Petroleum Inc. and Michael H. Lou (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on March 2, 2012, and incorporated herein by reference).
10.17**	Second Amended and Restated Employment Agreement dated as of December 23, 2013 between Oasis Petroleum Inc. and Taylor L. Reid (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 24, 2013, and incorporated herein by reference).
10.18**	Employment Agreement dated as of December 23, 2013 between Oasis Petroleum Inc. and Nickolas J. Lorentzatos (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on December 24, 2013, and incorporated herein by reference).
10.19**	Amended and Restated Executive Change in Control and Severance Benefit Plan dated as of March 1, 2012 (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on March 2, 2012, and incorporated herein by reference).

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Exhibit No.	Description of Exhibit
10.20	Purchase and Sale Agreement, dated September 4, 2013, by and among Oasis Petroleum North America LLC and two undisclosed private sellers (filed as Exhibit 2.1 to the Company's Current Report on Form 8-K on September 5, 2013, and incorporated herein by reference).
10.21	Purchase Agreement dated as of September 10, 2013 among the Company, the Guarantors and Wells Fargo Securities, LLC, as representative of the several initial purchasers (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on September 11, 2013, and incorporated herein by reference).
12.1(a)	Computation of Ratio of Earnings to Fixed Charges.
21.1(a)	List of Subsidiaries of Oasis Petroleum Inc.
23.1(a)	Consent of PricewaterhouseCoopers LLP.
23.2(a)	Consent of DeGolyer and MacNaughton.
31.1(a)	Sarbanes-Oxley Section 302 certification of Principal Executive Officer.
31.2(a)	Sarbanes-Oxley Section 302 certification of Principal Financial Officer.
32.1(b)	Sarbanes-Oxley Section 906 certification of Principal Executive Officer.
32.2(b)	Sarbanes-Oxley Section 906 certification of Principal Financial Officer.
99.1(a)	Report of DeGolyer and MacNaughton.
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Schema Document.
101.CAL(a)	XBRL Calculation Linkbase Document.
101.DEF(a)	XBRL Definition Linkbase Document.
101.LAB(a)	XBRL Labels Linkbase Document.
101.PRE(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith.
** Management contract or compensatory plan or arrangement.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized, on February 27, 2014.

OASIS PETROLEUM INC.

By: /s/ Thomas B. Nusz
Thomas B. Nusz
Chairman of the Board and
Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacity and on the dates indicated:

Signature	Title	Date
/s/ Thomas B. Nusz Thomas B. Nusz	Chairman of the Board and Chief Executive Officer (Principal Executive Officer)	February 27, 2014
/s/ Taylor L. Reid Taylor L. Reid	Director, President and Chief Operating Officer	February 27, 2014
/s/ Michael H. Lou Michael H. Lou	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2014
/s/ Roy W. Mace Roy W. Mace	Senior Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 27, 2014
/s/ William J. Cassidy William J. Cassidy	Director	February 27, 2014
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	February 27, 2014
/s/ Michael McShane Michael McShane	Director	February 27, 2014
/s/ Bobby S. Shackouls Bobby S. Shackouls	Director	February 27, 2014
/s/ Douglas E. Swanson, Jr. Douglas E. Swanson, Jr.	Director	February 27, 2014

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this Annual Report on Form 10-K:

"Bbl." One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"Bcf." One billion cubic feet of natural gas.

"Boe." Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"British thermal unit." The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Basin." A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

"Completion." The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

"Developed acreage." The number of acres that are allocated or assignable to productive wells or wells capable of production.

"Developed reserves." Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of required equipment is relatively minor when compared to the cost of a new well.

"Development well." A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole." A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Economically producible." A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"Environmental assessment." An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

"Exploratory well." A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

"Field." An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"Formation." A layer of rock which has distinct characteristics that differ from nearby rock.

"Horizontal drilling." A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

"Infill wells." Wells drilled into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

"MBbl." One thousand barrels of crude oil, condensate or natural gas liquids.

"MBoe." One thousand barrels of oil equivalent.

"Mcf." One thousand cubic feet of natural gas.

"MMBbl." One million barrels of crude oil, condensate or natural gas liquids.

"MMBoe." One million barrels of oil equivalent.

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"MMBtu." One million British thermal units.
"MMcf." One million cubic feet of natural gas.
"NYMEX." The New York Mercantile Exchange.
"Net acres." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.
"PV-10." When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the Commission.
"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.
"Proved developed reserves." Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
"Proved reserves." Those 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. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.
"Proved undeveloped reserves." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
"Reasonable certainty." A high degree of confidence.
"Recompletion." The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.
"Reserves." Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations.
"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible natural gas and/or oil that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies.

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"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.
"Wellbore." The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.
"Working interest." The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.
"Workover." The repair or stimulation of an existing productive well for the purpose of restoring, prolonging or enhancing the production of hydrocarbons.