

Eclipse Resources Corp
Form 10-K
March 09, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**
For the fiscal year ended December 31, 2014

or

.. **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE
SECURITIES EXCHANGE ACT OF 1934**
For the transition period from _____ to _____

Commission File Number: 001-36511

Eclipse Resources Corporation
(Exact name of registrant as specified in its charter)

Delaware
(State or other jurisdiction of
incorporation or organization)
2121 Old Gatesburg Rd, Suite 110

46-4812998
(I.R.S. Employer
Identification No.)

State College, PA
(Address of principal executive offices)

16803
(Zip code)

(814) 308-9754

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, Par Value \$0.01 Per Share	New York Stock 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 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

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 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 No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 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 No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a small reporting company. See the definitions of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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Large accelerated filer 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 Exchange Act). Yes No

The aggregate market value of the voting common stock held by non-affiliates of the registrant as of June 30, 2014, the last business day of the most recently completed second fiscal quarter, was approximately \$761 million.

Number of shares of the registrant's common stock outstanding at March 6, 2015: 222,531,115 shares.

Documents incorporated by reference: Portions of the registrant's proxy statement for its annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10-K.

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Cautionary Statement Regarding Forward-Looking Statements

This Annual Report on Form 10-K (the Annual Report) contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended (the Securities Act) and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and income/losses, projected costs and capital expenditures, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words will, would, could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. These forward-looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward-looking statements, you should keep in mind the risk factors and other cautionary statements described in Item 1A. Risk Factors of this Annual Report.

Forward-looking statements may include statements about, among other things:

our business strategy;

reserves;

general economic conditions;

financial strategy, liquidity and capital required for developing our properties and timing related thereto;

realized natural gas, NGLs and oil prices;

timing and amount of future production of natural gas, NGLs and oil;

our hedging strategy and results;

future drilling plans;

competition and government regulations, including those related to hydraulic fracturing;

the anticipated benefits under our commercial agreements;

pending legal matters relating to our leases;

marketing of natural gas, NGLs and oil;

leasehold and business acquisitions;

the costs, terms and availability of gathering, processing, fractionation and other midstream services;

credit markets;

uncertainty regarding our future operating results, including initial production rates and liquid yields in our type curve areas; and

plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

We caution you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. These risks include, but are not limited to, legal and environmental risks, drilling and other operating risks, regulatory changes, commodity price volatility, inflation, lack of availability of drilling, production and processing equipment and services, counterparty credit risk, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described in Item 1A. Risk Factors of this Annual Report.

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Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this Annual Report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward-looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward-looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report.

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Commonly Used Defined Terms

As used in this Annual Report, unless the context indicates or otherwise requires, the following terms have the following meanings:

Eclipse, Eclipse Resources, the Company, we, our, us and like terms refer collectively to Eclipse Resources Corporation and its consolidated subsidiaries, including Eclipse Resources I, LP, Eclipse Resources-Ohio, LLC, and Eclipse Resources Operating, LLC;

Eclipse I refers to Eclipse Resources I, LP, which is our predecessor for accounting purposes, and its consolidated subsidiaries;

Eclipse Holdings refers to Eclipse Resources Holdings, LP;

Eclipse Operating refers to Eclipse Resources Operating, LLC, which is our predecessor management company acquired as part of the reorganization completed at the time of IPO;

EnCap refers to EnCap Investments LP;

Oxford or The Oxford Oil Company refers to The Oxford Oil Company. Immediately prior to the Company's acquisition of Oxford, Oxford merged into Eclipse Resources-Ohio LLC;

Glossary of Oil and Natural Gas Terms and Companies

Antero Resources refers to Antero Resources Corporation;

Bbl A standard barrel containing 42 U.S. gallons;

Bbls/d Bbls per day;

Bcfe refers to one billion cubic feet of natural gas equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids;

Blue Racer refers to Blue Racer Midstream, LLC;

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Boe One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil;

Boe/d Boes per day;

Btu One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit;

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

Condensate or **Condensate Window** refers to the area within the Utica Core Area in which we expect the Utica Shale wells to produce a natural gas having a heat content between approximately 1,231 Btu and 1,280 Btu, with an initial condensate yield of between approximately 31 and 180 barrels per MMcf of natural gas produced;

Developed acreage refers to the number of acres that are allocated or assignable to productive wells or wells capable of production;

Differential An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas;

Dry Gas or **Dry Gas Window** refers to the area within the Utica Core Area in which we expect the Utica Shale wells to produce natural gas having a heat content of less than approximately 1,100 Btu with a negligible initial condensate yield;

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Dth is a thermal unit, and is equal to one million Btus;

Dry hole or dry well 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;

Eureka Hunter refers to Eureka Hunter Pipeline LLC, a subsidiary of Magnum Hunter Resources Corporation;

Exploration A development or other project that may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects;

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 that has distinct characteristics that differs from nearby rock;

Gross acres or gross wells The total acres or wells, as the case may be, in which a working interest is owned;

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;

Identified drilling locations refers to total gross (net) resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors;

MBbl One thousand barrels;

MBoe One thousand Boe;

Mcf One thousand cubic feet;

Mcfe refers to one thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;

Mcf/d Mcfs per day;

MMBbls One million barrels;

MMBoe One million Boe;

MMBtu One million British thermal units;

MMcf One million cubic feet;

Mcfe refers to one thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs;

Net acres refers to the amount of leased real estate that a petroleum and/or natural gas company has a true working interest in. Net acres express actual percentage interest when a company shares its working interest with another company; the total acreage under lease by a company is referred to as gross acres. Net acres account for the Company's percentage interest, multiplied by the gross acreage. If a company holds the entire working interest, its net acreage and gross acreage will be the same;

Net production Production that is owned by us less royalties and production due others;

NGLs Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline;

NYMEX The New York Mercantile Exchange;

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Operator The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease;

Plugging The sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface;

Productive well refers to a well that is expected to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceeds production expenses and taxes;

Prospect refers to a geological feature mapped as a location or probable location of a commercial oil and/ or gas accumulation. A prospect is defined as a result of geophysical and geological studies allowing the identification and quantification of uncertainties, probabilities of success, estimates of potential resources and economic viability;

Proved undeveloped reserves refers to 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;

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances;

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time;

(iii) Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir (as defined in Rule 4-10(a)(2) of Regulation S-X), or by other evidence using reliable technology establishing reasonable certainty;

PV-10 refers to, when used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using sales prices used in estimating proved oil and gas reserves 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 SEC;

Realized price The cash market price less all expected quality, transportation and demand adjustments;

Reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other

reservoirs;

Rich Condensate or Rich Condensate Window refers to the area within the Utica Core Area in which we expect the Utica Shale wells to produce natural gas having a heat content in excess of 1,280 Btu, with an initial condensate yield in excess of 180 barrels per MMcf of natural gas produced;

Rich Gas refers to the area within the Utica Core Area in which we expect the Utica Shale wells to produce natural gas having a heat content between approximately 1,100 Btu and 1,230 Btu, with an initial condensate yield between approximately 1 and 30 barrels per MMcf of natural gas produced;

SEC The United States Securities and Exchange Commission;

Spacing refers to 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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Spot market price The cash market price without reduction for expected quality, transportation and demand adjustments;

Standardized measure refers to discounted future net cash flows estimated by applying sales prices used in estimating proved oil and gas reserves to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate;

Undeveloped acreage Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves;

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 refers to the hole drilled by the bit that is equipped for oil or natural 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, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis;

WTI West Texas Intermediate;

The terms development project, development well, exploratory well, proved developed reserves, proved reserves and reserves are defined by the SEC;

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Items 1 and 2. Business and Properties

Our Company

We are an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. As of December 31, 2014, we had assembled an acreage position approximating 221,700 net acres in Eastern Ohio. Approximately 100,700 of our net acres are located in the Utica Shale fairway, which we refer to as the Utica Core Area, and approximately 27,250 of these net acres are also prospective for the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as Our Marcellus Project Area. Based on our initial drilling results, we believe the Utica and Marcellus shales offer some of the highest rate of return wells in North America. We are the operator of approximately 85% of our net acreage within the Utica Core Area and Our Marcellus Project Area. As of December 31, 2014, we had identified approximately 3,112 gross (810 net) remaining horizontal drilling locations across our acreage, comprised of 605 locations within the Utica Core Area and 205 locations within Our Marcellus Project Area. As of December 31, 2014, we and our operating partners had commenced drilling 179 gross wells within the Utica Core Area and 3 gross wells within Our Marcellus Project Area. We intend to focus on developing our substantial inventory of horizontal drilling locations and will continue to opportunistically add to this acreage position where we can acquire acreage at attractive prices.

Our Properties

We began assembling our acreage position in the Utica Core Area in 2011 based upon a rigorous analytical evaluation of the shale properties within the Utica and Point Pleasant formations across Eastern Ohio. Based upon this evaluation, we concentrated our acreage acquisition efforts in an area spanning parts of 5 counties that we believed would be the most prolific region of the play. Based upon production data from the wells we have drilled and participated in and our analysis of the results publicly released by other operators, we believe that our evaluation of the Utica Shale has been validated and that the Utica Core Area is the most prolific part of the play.

Across the Utica Core Area, the eastern boundary is more thermally mature and expected to produce dry gas, while the western boundary is less thermally mature and expected to produce a greater proportion of condensate and NGLs in addition to natural gas. We classify our acreage between these boundaries as being prospective for Dry Gas, Rich Gas, Condensate or Rich Condensate. We expect Our Marcellus Project Area to produce a significant proportion of condensate and NGLs in addition to natural gas. Additionally, we own approximately 121,000 net acres (which are approximately 86% held by production) outside of the Utica Core Area that may be prospective for the oil window of the Utica Shale.

Utica Shale

The Ordovician-aged Utica Shale is an unconventional reservoir comprised of organic-rich black shale, with most production occurring at vertical depths between 6,000 and 10,000 feet. The richest and thickest concentration of organic-carbon content is present within the Point Pleasant layer of the Lower Utica formation. Based on our geologic, engineering and petrophysical research, incorporating production data from wells we have drilled and participated in, as well as publicly disclosed well results from other operators in the play, we believe the Utica Shale is rapidly emerging as a premier North American unconventional resource play. To date, wells in the Utica Core Area in the southern portion of the Utica Shale play have yielded the strongest well results as measured by initial production rates. Our analysis of wells in the Utica Core Area fairway, which we believe to be the most prolific area of the play, indicates that single well rates of return in that region may rival any onshore resource play in North America.

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As of December 31, 2014, we had approximately 100,700 net acres in the Utica Shale in Eastern Ohio within the Utica Core Area. Across the Utica Core Area, the eastern boundary is more thermally mature and expected to produce dry gas, while the western boundary is less thermally mature and expected to produce a greater proportion of condensate and NGLs in addition to natural gas. As of December 31, 2014, we and our operating partners had turned to sales 97 gross (31.9 net) wells within the Utica Core Area.

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The Marcellus Shale consists of organic-rich black shale, with most production occurring at vertical depths between 5,000 and 8,000 feet. The Marcellus Shale is one of the most prolific North American shale plays due to its high well recoveries relative to drilling and completion costs, broad aerial extent, significant hydrocarbon resources in place and relatively homogenous high-quality reservoir characteristics.

As of December 31, 2014, we had approximately 27,250 net acres in the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as Our Marcellus Project Area. The reservoir underlying this acreage is less thermally mature than the Marcellus Shale in Southwestern Pennsylvania, and consequently, we believe natural gas production from this area will yield significant NGLs and condensate. As of December 31, 2014, we have participated in 3 gross (1.7 net) wells within Our Marcellus Project Area.

The table below outlines our Utica Core Area and Our Marcellus Project Area acreage and the remaining identified drilling locations within each type curve area as of December 31, 2014, after deducting wells that had been drilled or are in progress:

Type Curve Area	Net Acreage(1)	Identified Drilling Locations	
		Gross(1)	Net(1)
Dry Gas	34,850	715	207
Rich Gas	34,900	850	223
Condensate	25,650	558	130
Rich Condensate	5,300	418	45
Total Utica Core Area	100,700	2,541	605
Our Marcellus Project Area	27,250	571	205
Total		3,112	810

(1) Drilling locations are specifically identified and generally assume 1,000 foot interlateral spacing for acreage within the Dry Gas Window and 750 foot interlateral spacing elsewhere and a 6,000 foot lateral length.

Activity

Through December 31, 2014, we, or our operating partners, had commenced drilling 183 gross wells within the Utica Core Area and Our Marcellus Project Area, which are summarized below:

Type Curve Area	Operated Gross Wells Awaiting			Non-Operated Gross Wells Awaiting			
	Producing to Sales	Turn to Sales	Awaiting Completion/ Completing	Producing to Sales	Turn to Sales	Awaiting Completion/ Completing	Drilling

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Dry Gas	6				9	3	8	
Rich Gas	1		7		34	1	4	9
Condensate	21	9	12	12	25	1	6	11
Rich Condensate					1			
Total Utica Core Area	28	9	19	12	69	5	18	20
Our Marcellus Project Area	1				2			
Total	29	9	19	12	71	5	18	20

As of December 31, 2014, our estimated proved reserves were 355.8 Bcfe, or 59.3 MMBoe, an increase of 353% from December 31, 2013 reserves of 78.5 Bcfe, or 13.1 MMBoe, based on reserve reports prepared by Netherland, Sewell & Associates, Inc., or NSAI, our independent petroleum engineers. As of December 31,

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2014, our estimated proved reserves were approximately 72% natural gas, 18% NGLs and 10% oil, and approximately 55% were proved developed reserves. The following table provides information regarding our proved reserves as of December 31, 2014, 2013, and 2012:

	Estimated Total Proved Reserves						
	Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (Bcfe)	Total (MMBoe)	% Liquids	% Developed
December 31, 2012	0.4	0.2	3.0	6.3	1.1	54.5%	43.0%
December 31, 2013	2.4	1.9	52.3	78.5	13.1	33.3%	56.7%
December 31, 2014	5.7	10.9	256.3	355.8	59.3	28.0%	55.3%

Midstream Agreements

We have contracted for firm gathering, processing and fractionation capacity for a significant portion of our operated acreage in the Rich Gas, Condensate and Rich Condensate Windows of the Utica Core Area with Blue Racer, a joint venture between Dominion Resources, Inc. and Caiman Energy II, LLC. Additionally, we have contracted with Eureka Hunter for firm gathering services on a significant portion of our operated acreage in the Dry Gas Window of the Utica Core Area. Neither of these gas processing agreements require us to make minimum volume deliveries or shortfall payments.

We work closely with our midstream partners to coordinate our drilling and completion schedule with their well hook up and facility construction schedule to ensure sufficient capacity is available to minimize any delays in turning production into sales. Our non-operated production operated by Antero Resources is gathered and marketed by Antero Resources on our behalf and is currently being processed and fractionated through long-term contracts Antero Resources has with MarkWest Energy Partners, LP.

The following table illustrates the firm transportation and sales volumes associated with our operated assets:

Firm Sales & Transportation	Start Date	Term	Volume (Dth/d)	Market
Firm Sales	November 2014	Various	Up to 95,000	Dominion South/TETCO M2
TETCO	April 2015	9.5 years	100,000	Gulf Coast, Midwest, and M3
Rockies Express	June 2015	17 months	50,000	Midwest
TCO	November 2016	15 years	205,000	TCO Pool
Energy Transfer	December 2016	15 years	100,000	Gulf Coast
Energy Transfer	June 2017	15 years	50,000	Canada

In March 2014, we entered into a 20 year contract with Shell Chemical, LP (Shell Chemical) for the sale of ethane to Shell Chemical 's proposed Appalachian cracker project in Monaca, Pennsylvania. Under the terms of the contract, we would sell to Shell Chemical, at a minimum, all of our Must Recover Ethane (i.e., 30% of total recoverable ethane) at Blue Racer 's fractionation facility near Natrium, West Virginia. The agreement provides for Shell Chemical to make a positive election during 2015 to keep the supply agreement in effect.

In August 2014, we entered into an agreement with EnLink Midstream Operating, LP (Enlink Midstream) for the marketing of our condensate and operation of our condensate stabilization facilities. Under the terms of the agreement, among other things, EnLink Midstream will purchase two of our existing condensate stabilization facilities, as well as construct and operate additional facilities to support our drilling program in the Utica Shale. We completed the sale of

one of these two facilities to EnLink Midstream in December 2014.

On November 7, 2014, we entered into an additional transportation agreement on the Rockies Express pipeline for 50,000 Dth per day commencing in June 2015. This additional agreement will offer us the ability to market a significant portion our gas to the Midwest markets. With this additional transportation agreement, we believe we have firm transportation or firm sales agreements covering approximately 100% of our planned gross operated natural gas production during 2015 and 2016. In addition, we expect that the majority of our non-operated production will be marketed at advantaged markets predominately outside of the Appalachian Basin.

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In December 2014, we entered into a 10-year firm transportation and marketing agreement with Blue Racer to market a substantial portion of our operated production of propane and butane through Blue Racer's firm capacity on Sunoco's Mariner East II Project. The Mariner East II Project will connect the NGLs resources in the Marcellus and Utica Shale to Sunoco's existing infrastructure and international port at its Marcus Hook facility near Philadelphia. Mariner East II is expected to be operational in late 2016. Under the agreement, we will have firm transportation, which grows from approximately 7,500 barrels to 14,000 barrels per day during the term of the agreement (67% propane and 33% butane). Through this agreement, we plan to export propane and butane in order to capture the premium pricing offered by international markets, but also retain the ability to sell domestically.

We believe we will have sufficient production quantities to meet our volume commitments related to these various firm transportation agreements, but may choose to release excess capacity or purchase gas from third parties to satisfy shortfalls should they occur.

As of December 31, 2014, our firm transportation commitments through 2019 include:

Year ended December 31,	Volume of Natural Gas (MMBtu/d)	Volume of NGLs (Bbls/d)
2015	105,000	
2016	176,000	7,511
2017	434,000	10,373
2018	455,000	13,994
2019	456,000	11,628

The minimum demand fees related to these firm transportation agreements are reflected in our table of contractual obligations. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Cash Contractual Obligations.

See Item 1A. Risk Factors for a discussion of risks and uncertainties relating to our gathering, processing and fractionation arrangements.

Recent Developments***Private Placement of Common Stock***

On December 27, 2014, we entered into a Securities Purchase Agreement with the EnCap Funds, the Management Funds and the other stockholders pursuant to which we agreed to issue and sell to such purchasers an aggregate of 62,500,000 shares of common stock at a price of \$7.04 per share pursuant to the exemptions from registration provided in Rule 506 of Regulation D promulgated under Section 4(2) of the Securities Act, such transaction referred to herein as the private placement.

On January 28, 2015, we closed the private placement and received net proceeds from the issuance of the shares to the purchasers of approximately \$434 million (after deducting placement agent commissions and our estimated expenses), which we intend to use to fund our capital expenditure plan and for general corporate purposes. Upon the closing of the private placement, we amended and restated the existing registration rights agreement that we entered into upon the closing of our IPO to give the stockholders certain registration rights with respect to the stock purchased in the private placement.

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Amended and Restated Revolving Credit Facility

On January 12, 2015, we entered into an Amended and Restated Credit Agreement (the *Credit Agreement*) with Eclipse I, as borrower, the Bank of Montreal, as administrative agent and issuing bank, KeyBank National Association, as syndication agent, and each of the lenders party thereto. The Credit Agreement provides for a revolving credit facility of up to \$500 million, subject to borrowing base availability, and is scheduled to mature on January 15, 2018. The borrowing base under our revolving credit facility was \$100.0 million as of the effective date of the Credit Agreement and is subject to periodic redeterminations based on our oil and gas reserves. As of January 12, 2015, Eclipse I had no borrowings and approximately \$26.9 million of outstanding letters of credit, resulting in borrowing availability of approximately \$73.1 million under our revolving credit facility. In March 2015, we had a redetermination of the borrowing base under our revolving credit facility which increased the borrowing base to \$125 million.

The Credit Agreement amended and restated Eclipse I's previous credit agreement, dated as of February 18, 2014, as amended. The primary change effected by the Credit Agreement was to add Eclipse Resources Corporation as a party to the Credit Agreement and thereby subject us to the representations, warranties, covenants and events of default provisions thereof. Relative to the Eclipse I's previous credit agreement, the Credit Agreement also (i) requires financial reporting regarding, and tests financial covenants with respect to, us rather than Eclipse I, (ii) increases the basket sizes under certain of the negative covenants, and (iii) includes certain other changes favorable to Eclipse I. Other terms of the Credit Agreement remain generally consistent with Eclipse I's previous credit agreement. The previous revolving credit facility and the revolving credit facility provided for in the Credit Agreement are referred to herein as our Revolving Credit Facility.

Our Revolving Credit Facility is secured by mortgages on substantially all of Eclipse I's properties and guarantees from us and our subsidiaries (other than immaterial subsidiaries). Interest is payable at a variable rate based on LIBOR or the prime rate based on Eclipse I's election at the time of borrowing.

Initial Public Offering

On June 25, 2014, we completed our initial public offering (*IPO*) of 30,300,000 shares of our common stock, which included 21,500,000 shares sold by us and 8,800,000 shares sold by certain of our selling stockholders. Our net proceeds from our IPO were approximately \$544.7 million, after deducting underwriting discounts and commissions and the offering expenses payable by us of approximately \$35.8 million. We used a portion of the net proceeds we received from our IPO to repay the then-outstanding borrowings under Eclipse I's revolving credit facility and the remainder to fund our capital expenditure plan.

Corporate Reorganization

Pursuant to the terms of our corporate reorganization that was completed prior to the closing of our IPO, the following transactions occurred (collectively, our *Corporate Reorganization*):

the acquisition by Eclipse I of all of the outstanding equity interests in Eclipse Operating;

the contribution of equity interests in Eclipse I to Eclipse Holdings by the EnCap Funds, the Management Funds and Management Holdco, in exchange for similar equity interests in Eclipse Holdings;

the transfer of the outstanding equity interests in Eclipse GP, LLC, the general partner of Eclipse I, to Eclipse Holdings; and

the contribution of equity interests in Eclipse I and the outstanding equity interests in Eclipse GP, LLC, to us by Eclipse Holdings in exchange for 138,500,000 shares of our common stock.

As a result of these steps, we became a majority controlled direct subsidiary of Eclipse Holdings, and Eclipse I became a direct subsidiary of Eclipse Resources Corporation.

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Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Proved Reserves. Our historical proved reserve estimates were prepared by NSAI. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of NSAI's proved reserve reports as of December 31, 2014, December 31, 2013 and December 31, 2012 are attached hereto as exhibits.

We maintain an internal staff of engineers and geoscience professionals who work closely with NSAI to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets. Our internal technical team members meet with NSAI periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information for our properties to NSAI, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Bryan Moody, our Vice President Business Development and Reservoir Engineering, is primarily responsible for overseeing the preparation of all of our reserve estimates. Mr. Moody is an engineer with over 10 years of reservoir and operations experience and our geoscience staff has an average of approximately 8 years of industry experience per person.

The preparation of our proved reserve estimates are completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

review and verification of historical production data, which data is based on actual production as reported by us;

preparation of reserve estimates by Mr. Moody or under his direct supervision;

review by Mr. Moody of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new proved undeveloped reserves additions by our Chief Executive Officer, Chief Operating Officer and Chief Financial Officer;

direct reporting responsibilities by Mr. Moody to our Chief Operating Officer; and

verification of property ownership by our land department.

The reserves estimates shown herein are based upon evaluations prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical persons primarily responsible for preparing the estimates set forth in the NSAI reserves report incorporated herein are Mr. Robert C. Barg and Mr. William J. Knights. Mr. Barg has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Barg is a Licensed Professional Engineer in the State of

Texas (No. 71658) and has over 30 years of practical experience in petroleum engineering, with over 24 years of experience in the estimation and evaluation of reserves. He graduated from Purdue University in 1983 with a Bachelor of Science Degree in Mechanical Engineering. Mr. Knights has been practicing consulting petroleum geology at NSAI since 1991. Mr. Knights is a Licensed Professional Geoscientist in the State of Texas, Geology (No. 1532) and has over 33 years of practical experience in petroleum geosciences, with over 27 years of experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a Bachelor of Science Degree in Geology and in 1984 with a Master of Science Degree in Geology. Both technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; both are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

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Estimation of Proved Reserves. Under SEC rules, 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 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. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a high degree of confidence that the quantities will be recovered. All of our proved reserves as of December 31, 2014, December 31, 2013 and December 31, 2012 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties.

To estimate economically recoverable proved reserves and related future net cash flows, NSAI considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. 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. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Summary of Natural Gas, NGLs and Oil Reserves. The following table presents our estimated net proved natural gas, NGLs and oil reserves as of December 31, 2014, December 31, 2013 and December 31, 2012, based on the proved reserve reports prepared by NSAI, our independent petroleum engineers, and such proved reserve reports have been prepared in accordance with the rules and regulations of the SEC. Our estimated proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month price for each month in the period January through December for the years 2014, 2013 and 2012. For oil and NGLs volumes, the average West Texas Intermediate spot price of \$94.99 per barrel for December 31, 2014, \$96.91 per barrel for December 31, 2013 and \$94.71 per barrel for December 31, 2012, has been adjusted by property group for quality, transportation fees and regional price differentials. For gas volumes, the average Henry Hub spot price of \$4.35 per MMBtu for December 31, 2014, \$3.67 per MMBtu for December 31, 2013 and \$2.76 per MMBtu for December 31, 2012 has been adjusted by

property group for energy content, transportation fees and regional price differentials. All prices are held constant throughout the lives of the properties. All of our proved

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reserves are located in the United States. Copies of the proved reserve reports as of December 31, 2014, December 31, 2013 and December 31, 2012 prepared by NSAI with respect to our properties are included as exhibits this Annual Report on Form 10-K. Our estimates of net proved reserves have not been filed with or included in reports to any federal authority or agency other than the SEC.

	2014	2013	2012
Proved Developed Reserves:			
Natural gas (MMcf)	132,959.5	27,880.3	1,289.6
NGLs (MBbls)	6,758.6	1,056.2	64.6
Oil (MBbls)	3,880.9	1,708.1	174.5
Combined (MMcfe)	196,796.4	44,466.6	2,724.0
Proved Undeveloped Reserves:			
Natural gas (MMcf)	123,350.4	24,464.2	1,666.6
NGLs (MBbls)	4,120.4	882.1	112.4
Oil (MBbls)	1,816.4	709.2	211.5
Combined (MMcfe)	158,971.5	34,012.0	3,610.1
Proved Reserves:			
Natural Gas (MMcf)	256,309.9	52,344.5	2,956.1
NGLs (MBbls)	10,879.0	1,938.3	177.0
Oil (MBbls)	5,697.4	2,417.4	386.0
Combined (MMcfe)	355,767.9	78,478.6	6,334.2

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable 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 available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas, NGLs and oil that are ultimately recovered. Estimates of economically recoverable natural gas, NGLs and oil and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read Item 1A. Risk Factors appearing elsewhere in this Annual Report on Form 10-K.

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included in Item 8. Financial Statements and Supplementary Data and the proved reserve reports as of December 31, 2014, 2013, and 2012, which are included as exhibits to this Annual Report on Form 10-K.

Table of Contents***Proved Reserves Additions and Revisions***

To maintain and grow production and cash flow, we must continue to develop existing proved reserves and locate or acquire new natural gas, NGLs and oil reserves. The following is a discussion of net proved reserves, reserve additions and revisions and future net cash flows from proved reserves.

	Natural Gas (MMcf)	NGLs (MBbls)	Oil (MBbls)	Total (MMcfe)
Proved Reserves:				
December 31, 2011				
Extensions and discoveries	2,963.8	177.0	390.5	6,368.9
Production	(7.7)		(4.5)	(34.7)
December 31, 2012	2,956.1	177.0	386.0	6,334.2
Extensions and discoveries	41,215.5	1,710.6	1,323.3	59,419.0
Reserve revisions	2,645.0	52.1	(163.2)	1,978.4
Acquisition	6,646.6		958.5	12,397.6
Production	(1,118.8)	(1.3)	(87.2)	(1,650.2)
December 31, 2013	52,344.5	1,938.4	2,417.4	78,478.6
Extensions and discoveries	235,816.9	10,216.3	4,337.5	323,140.1
Reserve revisions	(12,091.2)	(739.7)	(462.6)	(19,305.3)
Acquisition				
Production	(19,760.2)	(536.0)	(594.9)	(26,545.5)
December 31, 2014	256,309.9	10,879.0	5,697.4	355,767.9

During the year ended December 31, 2014, we added 277.3 Bcfe of proved reserves, primarily due to drilling activities in the Utica Shale. This increase in proved reserves was comprised of 323.1 Bcfe of extensions, partially offset by 19.3 Bcfe of negative revisions and 26.5 Bcfe of production. The negative revisions consisted of 2.5 Bcfe of pricing revisions, 1.3 Bcfe related to expense assumptions, and 15.5 Bcfe due to technical revisions. During fiscal 2013, we added 72.1 Bcfe of proved reserves, primarily in the Utica Shale, due to drilling activities, evaluations of proved areas, the Oxford Acquisition and revisions to previous estimates.

Future Net Cash Flows. At December 31, 2014, 2013, and 2012 the PV-10 value of estimated future net cash flows from our proved reserves was \$509.4 million, \$155.3 million, and \$21.9 million, respectively. These PV-10 values were calculated based on the unweighted average first-day-of-the-month oil and gas prices for the prior twelve months held flat for the life of the reserves.

The following table sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV-10) and the present value of those net cash flows after income tax (standardized measure):

Year ended December 31,

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(In millions, except per Mcf data)	2014	2013	2012
Future net cash flows	\$ 792,091	\$ 286,855	\$ 36,151
Present value of future net cash flows:			
Before income tax (PV-10)	\$ 509,389	\$ 155,295	\$ 21,894
Income taxes	(178,732)		
After income tax (Standardized measure)	\$ 330,657	\$ 155,295	\$ 21,894

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 effects of income taxes on future net revenues. Prior to our Corporate Reorganization on June 24, 2014, we were not subject to entity level taxation, there was no difference between PV-10 and our standardized measure in this regard. However, as a result of our corporate reorganization, we are a corporation subject to federal income tax and our future income taxes will be

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dependent upon our future taxable income, and our calculation of standardized measure as of December 31, 2014 includes such tax inputs. Neither PV-10 nor standardized measure represents an estimate of the fair market value of our oil and natural gas properties. We and others in the industry use 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.

Proved Undeveloped Reserves (PUDs)

As of December 31, 2014 our proved undeveloped reserves were comprised of 1,816.4 MBbls of oil, 123,350.4 MMcf of natural gas and 4,120.4 MBbls of NGLs, for a total of 158,971.5 MMcfe. As of December 31, 2013, our proved undeveloped reserves were composed of 709.2 MBbls of oil, 24,464.2 MMcf of natural gas and 882.1 MBbls of NGLs, for a total of 34,012.0 MMcfe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

The following table summarizes our changes in PUDs during 2013 and 2014 (in MMcfe):

Balance, December 31, 2012	3,610.1
Revisions of previous estimates(1)	(271.0)
Purchases of minerals-in-place	
Extensions and discoveries	32,853.0
Transfers to proved developed	(2,180.2)
Balance, December 31, 2013	34,012.0
Revisions of previous estimates(2)	(25,959.4)
Purchases of minerals-in-place	
Extensions and discoveries	157,548.0
Transfers to proved developed	(6,629.1)
Balance, December 31, 2014	158,971.5

(1) Revisions to previous estimates are comprised of 270.9 MMcfe of negative technical revisions and 0.1 MMcfe of negative price revisions.

(2) Revisions to previous estimates are comprised of 1,033.8 MMcfe due to positive price revisions, 1,015.7 MMcfe negative revision due to expense assumptions, 25,977.5 MMcfe of negative technical revisions.

Costs incurred relating to the development of PUDs reflected in our 2012 proved reserve report were \$4.4 million during 2013. In addition, we incurred costs of \$0.3 million to develop locations that became classified as PUDs during 2013. Estimated future development costs relating to the development of PUDs as of December 31, 2014 are projected to be approximately \$34.3 million in 2015, \$21.2 million in 2016, \$135.9 million in 2017, \$64.9 million in 2018, and \$18.3 million in 2019. Of PUDs, we plan to develop 15%, or 24,639 MMcfe, in 2015, and 3%, or 4,522 MMcfe, in 2016. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in upcoming years. All of our PUD drilling locations are scheduled to be drilled prior to the end of 2019.

Table of Contents**Production and Price History**

The following table sets forth information regarding net production of natural gas, NGLs and oil, and certain price and cost information for the periods indicated:

	Year ended December 31,		
	2014	2013	2012
Total production volumes:			
Natural gas (MMcf)	19,760.2	1,118.8	7.7
NGLs (MBbls)	536.0	1.3	
Oil (MBbls)	594.9	87.2	4.5
Combined (MMcfe)	26,545.5	1,650.2	34.6
Average daily production volumes:			
Natural gas (Mcf/d)	54,137	3,065	21
NGLs (Bbls/d)	1,468	4	
Oil (Bbls/d)	1,630	239	12
Combined (Mcf/d)	72,727	4,521	95
Volume weighted average realized prices:			
Natural gas (\$/Mcf)(1)	\$ 3.51	\$ 3.85	\$ 3.53
NGLs (\$/Bbl)	39.27	48.17	
Oil (\$/Bbl)	79.54	98.22	76.19
Combined (\$/Mcf)	\$ 5.19	\$ 7.84	\$ 10.69
Expenses (per Mcfe):			
Lease operating	\$ 0.32	\$ 1.56	\$ 0.46
Transportation, gathering and compression	0.68	0.04	
Production, severance and ad valorem taxes	0.27	0.05	0.03
Depletion, depreciation and amortization	3.36	3.73	11.68
General and administrative	1.71	12.89	127.89

(1) Including the effects of commodity hedging, the average effective price for the year ended December 31, 2014 would have been \$4.57 per Mcf of gas. The total volume of gas associated with these hedges represented approximately 38% of our total sales volumes for the year ended December 31, 2014. There were no commodity derivatives in place as of or for the years ended December 31, 2013 and 2012.

For the year ended December 31, 2014, our revenue consisted of 50% natural gas, 15% NGLs, and 35% oil.

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2014 relating to our leasehold acreage. Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves. A gross acre is an acre in which a working interest is owned. The number of gross acres is

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the total number of acres in which a working interest is owned. A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Area	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net(1)	Gross	Net(1)	Gross	Net(1)
Ohio	175,668	143,833	114,618	77,904	290,286	221,737
West Virginia			307	177	307	177
Total	173,668	145,883	114,925	78,081	290,593	221,914

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- (1) Fossil Creek owns a right to participate for a 12.5% working interest in approximately 9,740 gross acres within our area of mutual interest with Antero Resources. In calculating our net acreage, we have assumed that Fossil Creek will elect to participate in all wells in which they have a right to participate for their full interest and have deducted this 12.5% working interest from our net acreage where applicable.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms, although approximately 52% of our leases in the Utica Core Area have a 5-year extension at our option. The following table sets forth the total gross and net undeveloped acres as of December 31, 2014 that will expire over the next five years unless operations have commenced on the leasehold acreage or lands pooled therewith have been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities:

Year ending December 31,	Gross Acres	Net Acres
2015	2,336	1,604
2016	16,036	4,721
2017	41,693	29,288
2018	20,441	11,303
2019 and beyond	13,641	12,237

We have not attributed any PUD reserves to acreage whose expiration date precedes the scheduled date for PUD drilling. In calculating our PUD reserves we have assumed that Fossil Creek will elect to participate in the drilling of these wells for their full interest and have deducted this interest when calculating our net PUD reserves.

Drilling Results

The following table sets forth information with respect to the number of wells completed during the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	100	33.6	34	30.7	1	0.3
Dry holes						
Exploratory Wells:						
Productive	1	.05	2	1.2		
Dry holes					1	1.0
Total:						
Productive	101	34.1	36	31.9	1	0.3
Dry holes					1	1.0

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As of December 31, 2013, we had 60 gross (23 net) wells in the process of drilling, completing or shut in awaiting infrastructure that are not reflected in the above table. As of December 31, 2014, we had 83 gross (39.5 net) wells in the process of drilling, completing or shut in awaiting infrastructure that are not reflected in the above table.

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Operations

General

As of December 31, 2014, we operated approximately 85% of our proved reserves. As operator, we design and manage the development of a well and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Major Customers

For the year ended December 31, 2014, sales to Antero Resources and ARM Energy Management represented approximately 47% and 25% of our total sales, respectively. For the year ended December 31, 2013, sales to Antero Resources, Devco Oil Inc., Dominion East Ohio, and Ergon represented approximately 38%, 24%, 13%, and 12% of our total sales, respectively. For the year ended December 31, 2012, Antero Resources accounted for 100% of our total sales. Although a substantial portion of production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as other customers or markets would be accessible to us.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include:

customary royalty interests;

liens incident to operating agreements and for current taxes;

obligations or duties under applicable laws;

development obligations under natural gas leases;

net profits interests;

mortgages by a lessor; or

rights of way or easements held by third parties such as utilities.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, some natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and

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exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Emerging Growth Company Status

We are an emerging growth company as defined in the Jumpstart Our Business Startups Act, or the JOBS Act. For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies under the JOBS Act, we are not required to:

provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act of 2002;

provide more than two years of audited financial statements and related management's discussion & analysis of financial condition and results of operations;

comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;

provide certain disclosure regarding executive compensation required of larger public companies or hold stockholder advisory votes on executive compensation as required by the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act; or

obtain stockholder approval of any golden parachute payments not previously approved.

We will cease to be an emerging growth company upon the earliest of:

the last day of the fiscal year in which we have \$1.0 billion or more in annual revenues;

the date on which we become a large accelerated filer (the fiscal year end on which the total market value of our common equity securities held by non-affiliates is \$700.0 million or more as of June 30);

the date on which we issue more than \$1.0 billion of non-convertible debt over a 3-year period; or

the last day of the fiscal year following the 5th anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period, and as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, 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 producing natural gas and oil

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properties have statutory provisions regulating the exploration for and production of natural gas and oil, 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 the regulation of the size of drilling and spacing units or proration units, the number of wells that may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratable 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 that we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict our future ability to comply with applicable law and regulations or the future costs or impact of compliance.

Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, or the FERC, and the courts. We cannot predict the substance or outcome of such proposals and proceedings or when or whether any such proposals may become effective. We believe we are in substantial compliance with currently 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. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

The production of natural gas and oil 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. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although in some cases we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of natural gas, NGLs and oil within its jurisdiction.

We own interests in properties located onshore in two U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas. The failure to comply with these rules and regulations can result in substantial penalties.

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Regulation of Transportation and Sales of Natural Gas

Historically, the transportation (including storage services) and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce and the revenues we receive for sales of our natural gas.

FERC's current policies allow for the sale of natural gas by producers at market-based prices. However, Congress could enact price controls in the future. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act, or NGA, and by regulations and orders promulgated under the NGA by FERC. In some limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The Energy Policy Act of 2005, or the EAct 2005, includes an extensive set of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that broadly affect the energy industry. Among other matters, the EAct 2005 amends the NGA to add an anti-market 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. The EAct 2005 provides FERC with the power to assess civil penalties of up to \$1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from \$5,000 per violation per day to \$1,000,000 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-market manipulation provision of the EAct 2005. The rules make it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas or 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, in light of the circumstances under which they were made, not misleading; or (3) engage in any act, practice or course of business that operates, or would operate, as a fraud or deceit upon any entity. The anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, 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.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now 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 704. Order 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. Reporting required under Order 704 is considered to constitute activities conducted in connection with gas sales, purchases or transportation subject to FERC jurisdiction.

We cannot reliably predict whether FERC's actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before FERC and the courts and new proposals and proceedings are likely to arise. The natural gas industry historically has been very heavily regulated and changing conditions and experience has led to changes in such

regulation. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by FERC 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, similarly-situated, natural gas producers.

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Gathering service is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which can increase our costs of getting gas to point of sale locations. State regulation of natural gas gathering facilities generally include 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.

Section 1(b) of the NGA excludes natural gas gathering facilities from regulation by FERC under the NGA. Further, an entity is not subject to regulation under NGA by FERC as a natural gas company solely by virtue of such entity owning or operating such facilities. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to determine that the owner/operator of such facilities is not subject to regulation as a natural gas company under the NGA. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation and FERC and Congress have discretion to revise the jurisdictional line. Consequently, the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. 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.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action Congress or FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other, similarly-situated, natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

General

Our operations are subject to numerous federal, regional, state, local, and other laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Applicable U.S. federal environmental laws include, but are not limited to, the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, the Clean Water Act, or the CWA, and the Clean Air Act, or the CAA. These laws and regulations govern environmental cleanup standards, require permits for air, water, underground injection, solid and hazardous waste disposal and set environmental compliance criteria. In addition, state and local laws and regulations set forth specific standards for drilling wells, the maintenance of bonding requirements in order to drill or operate

wells, the spacing and location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells, and the prevention and cleanup of pollutants and other matters. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. Additionally, Congress

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and federal and state agencies frequently revise environmental laws and regulations, and any changes that result in delay or more stringent and costly permitting, waste handling, disposal and clean-up requirements for the oil and gas industry could have a significant impact on our operating costs.

In addition, public and regulatory scrutiny of the energy industry has resulted in increased environmental regulation and enforcement being either proposed or implemented. For example, the EPA's 2014-2016 National Enforcement Initiatives include Assuring Energy Extraction Activities Comply with Environmental Laws. According to the EPA's website, some techniques for natural gas extraction pose a significant risk to public health and the environment. To address these concerns, the EPA's goal is to address incidences of noncompliance from natural gas extraction and production activities that may cause or contribute to significant harm to public health and/or the environment. The EPA has emphasized that this initiative will be focused on those areas of the country where energy extraction activities are concentrated, and the focus and nature of the enforcement activities will vary with the type of activity and the related pollution problem presented. This initiative could involve a large scale investigation of our facilities and processes, and could lead to potential enforcement actions, penalties or injunctive relief against us.

Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal fines and penalties and the imposition of injunctive relief. Noncompliance could also result in an increase in capital expenditures or reduced earnings and hurt our ability to compete in the marketplace. Accidental releases or spills may occur in the course of our operations, and we cannot be sure 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. Although we believe that we are in substantial compliance with applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on us, there can be no assurance that this will continue in the future.

The Safe Drinking Water Act and the Underground Injection Control Program

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from subsurface rock formations. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or the SDWA, over hydraulic fracturing activities involving the use of diesel fuel. From time to time, however, Congress has proposed legislation to amend the SDWA to repeal the exemption for hydraulic fracturing from the definition of underground injection and require federal permitting and regulatory control of all hydraulic fracturing activities, as well as to require disclosure of the chemical constituents of the fluids used in the fracturing process. Scrutiny of hydraulic fracturing activities by the EPA continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, draft results of which are anticipated to be available in 2014. In addition, on October 20, 2011, the EPA announced its intention to propose regulations by 2014 under the CWA to develop standards for wastewater discharges from hydraulic fracturing and other natural gas production activities. According to EPA's website, the agency expects publication of a proposed rule in 2015. Moreover, the United States Department of the Interior published a revised proposed rule on May 24, 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the United States Department of Energy have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. In Ohio, the Department of Natural Resources has proposed draft regulations that would require a minimum distance between the hydraulic fracturing facilities and streams, require operators to take spill-containment measures, and regulate the types of liners required for waste storage. Local governments may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic

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fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless regulations can be expected to become stricter in the future, and, 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.

Hazardous Substances and Wastes

CERCLA, also known as the Superfund law, imposes cleanup obligations, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that transported or disposed or arranged for the transport or disposal of the hazardous substances found at the site. Persons who are or were responsible for releases of hazardous substances under CERCLA and any state analogs may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file corresponding common law claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. While petroleum and crude oil fractions are not considered hazardous substances under CERCLA and its analog because of the so-called petroleum exclusion, adulterated petroleum products containing other hazardous substances have been treated as hazardous substances in the past.

The Resource Conservation and Recovery Act, or the RCRA, regulates the generation and disposal of wastes. The RCRA specifically excludes from the definition of hazardous waste drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy. However, legislation has been proposed from time to time that could reclassify certain natural gas and oil exploration and production wastes as hazardous wastes, which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general. Moreover, some ordinary industrial wastes which we generate, such as paint wastes, waste solvents, laboratory wastes and waste oils, may be regulated as hazardous wastes.

In addition, current and future regulations governing the handling and disposal of Naturally Occurring Radioactive Materials, or NORM, may affect our operations. For example, the Ohio Department of Natural Resources has asked operators to identify technologically enhanced NORM, or TENORM, in their processes, such as hydraulic fracturing sand, recycled drilling mud, and spent tank bottoms. Local landfills only accept such waste when it meets their TENORM standards. As a result, we may have to locate out-of-state landfills to accept TENORM waste from time to time, potentially increasing our disposal costs.

Some of our leases may have had prior owners who commenced exploration and production of natural gas and oil operations on these sites. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons or other wastes may have been disposed of or released on or under the properties owned or leased by us on or under other locations where such wastes have been taken for disposal. In addition, a portion of these properties may have been operated by third parties whose treatment and disposal or release of wastes was not under our control. These properties and the wastes disposed thereon may be subject to CERCLA, the RCRA, and/or analogous state laws. Under such laws, we could be required to remove or remediate previously disposed wastes (including waste disposed of or released by prior owners or operators) or property contamination (including groundwater contamination by prior owners or operators), or to perform remedial plugging or closure operations to

prevent future contamination.

Waste Discharges

The CWA and its state analog impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge

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of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of federal laws require appropriate containment berms and similar structures to help prevent the contamination of navigable waters by a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Air Emissions

The CAA and its state analog and regulations restrict the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. On April 17, 2012, the EPA also approved final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. These new rules address emissions of various pollutants frequently associated with oil and natural gas production and processing activities by, among other things, requiring new or reworked hydraulically-fractured gas wells to control emissions through flaring until 2015, after which reduced emission (or green) completions must be used. The rules also establish specific new requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants, and certain other equipment. On September 23, 2013, EPA published amendments to the rule that would, among other things, provide additional time for recently constructed, modified or reconstructed storage tanks to install emission controls. EPA is continuing to consider other aspects of the new rules and may propose additional amendments in early 2014. These rules may require a number of modifications to our own operations, including the installation of new equipment to control emissions. Compliance with such rules could result in additional costs for us and our customers, including increased capital expenditures and operating costs, which may adversely impact our cash flows and results of operations.

Oil Pollution Act

The Oil Pollution Act of 1990, or the OPA, and regulations thereunder impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in United States waters. A responsible party includes the owner or operator of an onshore facility, pipeline or vessel, or the lessee or permittee of the area in which an offshore facility is located. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or the NEPA. The NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. The process involves the preparation of

either an environmental assessment or environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the human environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific

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mitigation. The NEPA decisions can be appealed through the court system by process participants. This process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of existing leases.

Endangered Species Act and Migratory Bird Treaty Act

The Endangered Species Act, or the ESA, and similar applicable state legislation restrict activities that may affect endangered or threatened species of their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Moreover, as a result of a settlement approved by the United States District Court for the District of Columbia in September 2011, the United States Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. For example, regulations designed to protect the Indiana bat (*Myotis soldalis*), which is an endangered species protected by the ESA and similar state legislation, restrict or increase the cost of our operations by, among other things, limiting our ability to clear trees to establish rights of way or pad locations on some of our acreage during certain periods of the year. While some of our operations may be located in areas that are designated as habitats for endangered or threatened species or that may attract migratory birds we believe that we are in substantial compliance with the ESA, similar applicable state legislation and the Migratory Bird Treaty Act, and we are not aware of any proposed ESA listings that will materially affect our operations. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected states.

Worker Safety

The Occupational Safety and Health Act, or the OSHA, and any analogous state law regulate the protection of the safety and health of workers. The OSHA hazard communication standard requires maintenance of information about hazardous materials used or produced in operations and provision of such information to employees. Other OSHA standards regulate specific worker safety aspects of our operations. Failure to comply with OSHA requirements can lead to the imposition of penalties.

Employees

As of December 31, 2014, we had 227 full-time employees. 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 utilize the services of independent contractors to perform various field and other services.

Corporate Information

Our principal executive offices are located at 2121 Old Gatesburg Road, Suite 110, State College, Pennsylvania 16803, and our telephone number is (866) 590-2568. Our website is www.eclipseresources.com. We expect to make our periodic reports and other information filed with, or furnished to, the Securities and Exchange Commission, or the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with, or furnished to, the SEC. The information on, or otherwise accessible through, our website or any other website does not constitute a part of this Annual Report on Form 10-K.

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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 www.sec.gov. Our common stock is listed and traded on the New York Stock Exchange under the symbol ECR. 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.

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 occur, our business, financial condition or results of operations could suffer. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect our company.

Risks Related to Our Business

Our operating history is limited and as a result there is only limited historical financial and operating information available upon which to base an evaluation of our performance. Moreover, the historical financial and operating information included in this Annual Report on Form 10-K may not be indicative of our future financial performance.

Our operating history is limited and as a result there is only limited historical financial and operating information available upon which to base an evaluation of our performance. Moreover, the historical financial and operating information included in this Annual Report on Form 10-K may not be indicative of our future financial performance. Additionally, the historical financial and operating data relating to the Oxford Acquisition included in this Annual Report on Form 10-K is largely derived from the conventional, vertical drilling of natural gas and oil wells, while we expect our post-acquisition strategy to focus on the horizontal drilling of natural gas and oil wells. Moreover, we plan to expand our drilling operations significantly in the near future. We have yet to generate positive earnings from our current business strategy and there can be no assurance that we will ever operate profitably. If our current business strategy is not successful, and we are not able to operate profitably, investors may lose some or all of their investment.

Natural gas, NGLs and oil prices are volatile. A substantial or extended decline in commodity 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 prices we receive for our natural gas, NGLs and oil production heavily influence our revenue, operating results profitability, access to capital, future rate of growth and carrying value of our properties. Natural gas, NGLs and oil are commodities, and therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities markets 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, but are not limited to, the following:

worldwide and regional economic conditions impacting the global supply of and demand for natural gas, NGLs and oil;

the price and quantity of imports of foreign natural gas, including liquefied natural gas, foreign oil and refined products;

the price and quantity of exported domestic crude oil, natural gas, including liquefied natural gas, NGLs and refined products;

political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;

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the level of global exploration and production;

the level of global inventories;

prevailing prices on local price indexes in the areas in which we operate and expectations about future commodity prices;

the proximity, capacity, cost and availability of gathering and transportation facilities, and other factors that result in differentials to benchmark prices;

the cost of exploring for, developing, producing and transporting reserves;

speculative trading in natural gas and crude oil derivative contracts;

risks associated with operating drilling rigs;

the price and availability of competitors' supplies of natural gas, NGLs, oil and alternative fuels;

localized and global supply and demand fundamentals and transportation availability;

adverse or severe weather conditions and other natural disasters;

technological advances affecting energy consumption and production; and

domestic, local and foreign governmental regulation and taxes.

In addition, substantially all of our natural gas production and oil production is sold to purchasers under contracts with market-based prices based on New York Mercantile Exchange (NYMEX) Henry Hub prices and West Texas Intermediate (WTI) prices, respectively. The actual prices realized from the sale of natural gas and oil differ from the quoted NYMEX Henry Hub and WTI prices as a result of location differentials. Location differentials to NYMEX Henry Hub and WTI prices, also known as basis differential, result from variances in regional natural gas and oil prices as compared to NYMEX Henry Hub and WTI prices due to regional supply and demand factors. We may experience differentials to NYMEX Henry Hub and WTI prices in the future, which may be material and could reduce the price we receive for these products relative to these benchmarks.

Lower commodity prices and negative increases in our differentials will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, or at all, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices and negative differentials could also cause a

significant portion of our development and exploration projects to become uneconomic, which may result in our having to make significant downward adjustments to our reserves. As a result, a substantial or extended decline in commodity prices or an increase in our negative differentials may materially adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

The information regarding third party wells included in this Annual Report on Form 10-K may not be reliable, and we may not be able to achieve similar results for our wells located near to those third party wells.

We have included in this Annual Report on Form 10-K publicly disclosed data related to initial production rates, liquids yields and other production and operating data for third party wells that have been drilled and completed on or near our acreage. This information was gathered from government databases, press releases and other publicly available sources as well as internally with respect to those wells in which we have an interest and access to such information. Other than a limited review with respect to those wells in which we own an interest, we have not undertaken any investigation to confirm the accuracy, completeness or reliability of this information or the methodology used by the third parties to determine this information, and such information may be materially incorrect, incomplete or unreliable. Furthermore, we obtained the information from multiple sources, and those sources may have been using inconsistent or incompatible methodologies. If the third party well information we have included in this Annual Report on Form 10-K is incorrect, incomplete or unreliable, then it may be inappropriate to expect wells that we drill and operate in our nearby acreage to perform at or near the

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levels indicated in the third party well information. Even if such information is reliable, drilling for oil and gas wells is a highly speculative undertaking, and there are many factors that affect the performance and yield of oil and gas wells, including decisions that we, our operating partners or other operators make regarding the drilling process, the geological features underlying the specific well, and other factors that are beyond our control. Moreover, initial production rates and liquids yields reported by us or other operators may not be indicative of future or long-term production rates and reserve potential. Accordingly, some or all of these factors, or factors that we do not or cannot anticipate, may cause the performance and yields of our wells to be substantially inferior to the actual or implied performance and yields of the nearby third party wells. As a result, our business, financial condition and results of operations could be substantially negatively affected.

We are involved in lawsuits challenging the validity of some of our leases, which if unfavorably resolved, may materially adversely affect our financial condition, business prospects and the value of our common stock.

Prior to the Oxford Acquisition, Oxford commenced a lawsuit on October 24, 2011 in the Common Pleas Court of Belmont County, Ohio against Mr. Barry West, a lessor under an Oxford oil and gas lease, to enforce its rights to access and drill a well on the lease during its initial 5-year primary term, which we refer to as the West Lawsuit. The lessor counterclaimed, alleging, among other things, that the challenged Oxford lease constituted a lease in perpetuity and, accordingly, should be deemed void and contrary to public policy in the State of Ohio. On October 4, 2013, the Belmont County trial court granted a motion for summary judgment in favor of the lessor and ruled that the lease is a no term perpetual lease and, as such, is void as a matter of Ohio law.

We have appealed the trial court's decision in the West Lawsuit to the Ohio Court of Appeals for the Seventh Appellate District, arguing, among other things, that the Belmont County trial court erred in finding that the lease is a no term perpetual lease, by ruling that perpetual leases are void as a matter of Ohio law and by invalidating such lease. We cannot predict the outcome of this lawsuit or the amount of time and expense that will be required to resolve the lawsuit.

In addition, many of our other oil and gas leases in Ohio contain provisions identical or similar to those found in the challenged Oxford lease. As of March 6, 2015, we are a party to one other lawsuit that makes allegations similar to those made by the lessor in the West Lawsuit. This lawsuit, together with the West Lawsuit, affect approximately 157 gross (157 net) leasehold acres and were capitalized on our balance sheet as of December 31, 2014 at \$0.6 million.

We have undertaken efforts to amend the other leases acquired within the Utica Core Area in the Oxford Acquisition to address the issues raised by the trial court's ruling in the West Lawsuit. These efforts have resulted in modifications to leases covering approximately 34,256 net acres out of the approximately 46,549 net acres we believe may require modification to address the issues raised by the trial court in the West Lawsuit. However, we cannot predict whether we will be able to obtain modifications of the leases covering the remaining 12,293 net acres to effectively resolve issues related to the Belmont County trial court's ruling in the West Lawsuit or the amount of time and expense that will be required to amend these leases and our other leases may also require modification to address such issue.

In light of the foregoing, if the appeals court affirms the trial court ruling in the West Lawsuit, and if other courts in Ohio adopt a similar interpretation of the provisions in other oil and gas leases we acquired in the Oxford Acquisition, other lessors may challenge the validity of such leases and those challenged leases may be declared void. Consequently, this could result in a loss of our mineral rights and an impairment of our related assets, and our ability to execute our planned drilling program as described in this Annual Report on Form 10-K could be substantially diminished. In addition, lawsuits concerning the validity of our leases could divert the attention of management and resources in general from day-to-day operations. An unfavorable resolution could, therefore, have a material adverse effect on our financial condition, business prospects and the value of our common stock.

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For further information regarding this lawsuit, please see Item 3. Legal Proceedings.

Changes in laws or government regulations regarding hydraulic fracturing could increase our costs of doing business, limit the areas in which we can operate and reduce our oil and natural gas production, which could adversely impact our business.

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. Hydraulic fracturing involves the injection of water, sand or alternative proppant and additives under pressure into target geological formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Presently, hydraulic fracturing is regulated primarily at the state level, typically by state oil and natural gas commissions and similar agencies. However, with increased public concern regarding the potential for hydraulic fracturing to adversely affect drinking water supplies, proposals have been made to enact federal, state and local legislation and regulations that would increase the regulatory burden imposed on hydraulic fracturing. For example, the U.S. Environmental Protection Agency, or the EPA, has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act, issued new air emission controls for oil and natural gas production and natural gas processing operations, initiated a study to examine the potential impacts of hydraulic fracturing on drinking water resources, and intends to propose standards for wastewater discharges from oil and gas extraction activities and regulations that would require companies to disclose information regarding the in hydraulic fracturing. The U.S. Congress continues to consider amending the Safe Drinking Water Act to remove the exemption for hydraulic fracturing activities and to require disclosure of additives constituents of fluids used in the fracturing process. The Department of the Interior proposed a rule that would regulate hydraulic fracturing activities on federal lands.

If new federal, state or local laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could result in delays, eliminate certain drilling and injection activities and make it more difficult or costly for us to perform fracturing. Any such regulations limiting or prohibiting hydraulic fracturing could reduce our oil and natural gas exploration and production activities and, therefore, adversely affect our business. Such laws or regulations could also materially increase our costs of compliance and doing business by more strictly regulating how hydraulic fracturing wastes are handled or disposed.

Properties that we decide to drill may not yield natural gas, NGLs or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas, NGLs or oil in commercially viable quantities will adversely affect our results of operations and financial condition. Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. If the wells in the process of being drilled and completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. In addition, there is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas, NGLs or oil in sufficient quantities to recover drilling and completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas, NGLs or oil will be present or, if present, whether natural gas, NGLs or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

unexpected drilling conditions;

title problems;

pressure or lost circulation in formations;

equipment failure or accidents;

adverse weather conditions;

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compliance with environmental and other governmental or contractual requirements; and

increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

Hydrocarbon windows, phases or type curve areas have an inherent degree of variability and may change over time, and as a result, the available well data with respect to such windows, phases and type curve areas may not be indicative of the actual hydrocarbon composition for the windows, phases or type curve areas.

Based upon the well data available to us, we have grouped the publicly disclosed Utica Shale wells within the Utica Core Area into several distinct hydrocarbon windows, phases or type curve areas in an effort to better understand the thermal maturation variability within the Utica Core Area. However, there is an inherent degree of variability within such hydrocarbon windows, phases or type curve areas. Additionally, the well data we have utilized is predominantly based upon initial production rate, Btu content, natural gas yields and condensate yields, which may change over time. As a result, the well data with respect to the windows, phases and type curve areas within the Utica Core Area may not be indicative of the actual hydrocarbon composition for the windows, phases or type curve areas, or may not be the hydrocarbon composition of the windows, phases or type curve areas at the time we drill. Due to such factors, the performance, Btu content and NGLs and/or condensate yields of our wells may be substantially less than we anticipate or substantially less than performance and yields of other operators in the Utica Core Area, which may materially adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our development and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the development and acquisition of oil and natural gas reserves. We expect to fund our capital expenditures in 2015 with cash on hand, cash generated by our operations, borrowings under our revolving credit facility. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices and differentials, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in realized natural gas, NGLs or oil prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flows from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flows from operations to fund working capital, capital expenditures and acquisitions.

Our cash flows from operations and access to capital are subject to a number of variables, including, without limitation, the following:

our proved reserves;

the volumes and types of hydrocarbons we are able to produce from existing and future wells;

the prices at which our production is sold;

our ability to acquire, locate and develop new reserves;

the levels of our operating expenses; and

our ability to borrow under our revolving credit facility and issue additional debt and equity securities. If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas, NGLs or oil prices, operating difficulties, declines in reserves or for any other reason, we may have limited

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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 acceptable to us, if at all. If our cash on hand, cash flows generated by our operations and available borrowings under our revolving credit facility are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

We have been an early entrant into the Utica Core Area, which is a new and emerging play, and are also an early entrant into the portion of the Marcellus Shale underlying Our Marcellus Project Area. As a result, our expected well results in these areas are uncertain, and the value of our undeveloped acreage will decline if well results are unsuccessful.

Our expected well results in the Utica Core Area and Our Marcellus Project Area are more uncertain than well results in areas that are more developed and have a greater number of producing wells. As a result, our cost of drilling, completing and operating wells in the Utica Core Area and Our Marcellus Project Area may be higher than initially expected, the ultimate production and reserves from these wells may be lower than initially expected and the value of our undeveloped acreage may decline. Additionally, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. We cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Initial production rates may not be a reliable or accurate predictor of ultimate well recoveries, and initial production rates may not be directly correlated to completed well lateral lengths.

We have shown initial production rates for publicly available Utica and Marcellus Shale wells to demonstrate the apparent relative strength or weakness of certain wells in the Utica and Marcellus Shales in our project areas. While we believe that the presentation of these initial production rates can provide a useful tool in evaluating the early stage performance of these wells for comparative analysis, in many cases initial production rates may not be a reliable or accurate predictor of ultimate well recoveries, which require significantly more in depth analysis, including but not limited to, an analysis of the production over an extended period. Initial production rates can also vary across wells due to several variables such as the choke size being utilized on the well, the lack of compression, the time period measured, or natural gas line pressures. Additionally, we have shown normalized initial production rates for several Utica Shale wells which have adjusted the reported initial production rate for these wells proportionate to the difference between their actual complete lateral length and a 6,000 foot complete lateral length. While we believe the presentation of this information can provide the ability to compare wells without regard to the varying actual completed lateral length of the wells we have presented, there may not be a direct correlation of initial production rates to the completed lateral length.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us, other oil and gas exploration and production companies and our service providers. Risks that we face while drilling include, but are not limited to, the following:

drilling wells that are significantly longer and/or deeper than more conventional wells;

landing our wellbore 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 wellbore; and

being able to run tools and other equipment consistently through the horizontal wellbore.

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Risks that we face while completing our wells include, but are not limited to, the following:

the ability to fracture stimulate the planned number of stages;

the ability to run tools the entire length of the wellbore during completion operations; and

the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

Drilling for and producing natural gas, NGLs and oil are high-risk activities with many uncertainties that could result in a total loss of investment or otherwise adversely affect our business, financial condition and results of operations.

Our future financial condition and results of operations will depend on the success of our development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable production or that we will not recover all or any portion of our investment in such wells.

Our decisions to purchase, explore or develop prospects 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 Business Oil and Natural Gas Data. Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could materially reduce our borrowing capacity. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including, without limitation, the following:

compliance with regulatory requirements, including limitations resulting from wastewater disposal, discharge of greenhouse gases, and limitations on hydraulic fracturing;

pressure or irregularities in geological formations;

shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;

equipment failures, accidents or other unexpected operational events;

lack of available gathering and processing facilities or delays in construction of gathering and processing facilities;

lack of available capacity on interconnecting transmission pipelines;

adverse weather conditions, such as blizzards and ice storms;

issues related to compliance with environmental regulations;

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 gases or other pollutants into the surface and subsurface environment;

terrorist (including eco-terrorist) attacks targeting natural gas and oil related facilities and infrastructure;

declines in natural gas, NGLs and oil prices;

limited availability of financing at acceptable terms;

title problems and well permit objections from coal operators; and

limitations in the market for natural gas.

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Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties.

We have incurred losses from operations since our inception and may do so in the future.

We incurred a net loss of \$8.8 million for the year ended December 31, 2012, a net loss of \$43.5 million for the year ended December 31, 2013 and a net loss of \$183.2 million for the year ended December 31, 2014. Our development of and participation in an increasingly larger number of prospects has required, and will continue to require, substantial capital expenditures. The uncertainty and factors described throughout this Risk Factors section may impede our ability to economically find, develop and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future, which could adversely affect the trading price of our common stock.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our senior unsecured notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness when due.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, raise additional capital or restructure or refinance indebtedness. Our ability to raise additional capital or restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our revolving credit facility and the indenture governing our senior unsecured notes currently restrict our ability to dispose of assets and our use of the proceeds from any such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

As of December 31, 2014, the borrowing base under our revolving credit facility was \$100.0 million, and there were no outstanding borrowings and approximately \$26.9 million of outstanding letters of credit, resulting in borrowing availability of approximately \$73.1 million under our revolving credit facility million was drawn. The borrowing base under our revolving credit facility is subject to periodic redeterminations based on our oil and gas reserves. In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination, unwillingness of the lenders to increase their aggregate commitment up to an increased borrowing base amount or an unwillingness or inability on the part of one or more lenders to meet their funding obligations and the inability of other lenders to provide additional funding to cover each defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future, and in such a case, we

could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

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Our producing properties are concentrated in the Appalachian Basin, which makes us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin. At December 31, 2014, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages, weather related conditions or interruption of the processing or transportation of natural gas, NGLs or oil. Such delays or interruptions could have a material adverse effect on our financial condition and results of operations. In addition, a number of areas within the Appalachian Basin have historically been subject to mining operations, the existence of which could require coordination to avoid adverse impacts as a result of drilling and mining in close proximity. These restrictions on our operations, and any similar restrictions, can cause delays or interruptions or can prevent us from executing our business strategy, which could have a material adverse effect on our financial condition and results of operations.

Due to the concentrated nature of our portfolio of natural gas and oil 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.

We own non-operating interests in properties developed and operated by third parties, and as a result, we are unable to control the operation and profitability of such properties.

We frequently participate as a non-operator in the drilling and completion of wells with third parties that exercise exclusive control over such operations. As a non-operator participant, we rely on the third party operating company to successfully operate these properties pursuant to joint operating agreements and other similar contractual arrangements.

As a non-operator participant in these operations, we may not be able to maximize the value associated with these properties in the manner we believe appropriate, or at all. For example, we cannot control the success of drilling and development activities on properties operated by third parties, which depend on a number of factors under the control of a third party operator, including such operator's determinations with respect to, among other things, the nature and timing of drilling and operational activities, the timing and amount of capital expenditures and the selection of suitable technology. In addition, the third party operator's operational expertise and financial resources and ability to gain the approval of other participants in drilling wells will impact the timing and potential success of our drilling and development activities in a manner that we are unable to control. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are favorable to us could reduce our production and revenues, negatively impact our liquidity and cause us to spend capital in excess of our current plans, and have a material adverse effect on our financial condition and results of operations.

Our existing providers of gas gathering, processing and fractionation capacity may not be able to provide to us sufficient capacity for our production from the Utica Core Area, and as a result, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production from the Utica Core Area, which alternative arrangements may not be available on favorable terms, or at all.

A significant portion of our Utica Core Area acreage position is dedicated to long-term firm gas gathering, processing and fractionation agreements with primary terms of approximately 15 years. These agreements give us priority service and capacity over non-firm parties that wish to utilize the gas processing and fractionation plants and gas gathering

system. As a result of such dedications, a significant portion of our operated acreage in the Rich Gas, Condensate and Rich Condensate Windows of the Utica Core Area is committed to Blue Racer for gathering, processing and fractionation. Additionally, a significant portion of our operated acreage in the Dry Gas Window of the Utica Core Area is committed to Eureka Hunter for gathering. While we believe we have reserved

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sufficient capacity at these plants and on such systems to gather, process and fractionate all of our projected production associated with our proved resources and a significant portion of our projected production from the Utica Core Area, that capacity may not be sufficient to handle all of our production or that the plants and systems will not experience significant mechanical problems or delays in construction or become unavailable to us due to unforeseen circumstances. As a result, we may be required to find alternative markets and gathering, processing or fractionation arrangements for our production from the Utica Core Area that is committed under these agreements, and such alternative arrangements may only be available on less favorable terms, or not at all.

Insufficient takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas prices.

The Appalachian Basin natural gas business environment has historically been characterized by periods in which production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers. Although additional Appalachian Basin takeaway capacity has been added in recent years and several new projects to further expand this capacity have been announced, there may not be sufficient capacity to keep pace with the increased production caused by accelerated drilling in the basin. We expect that a significant portion of our production from the Utica and Marcellus Shales will be transported on pipelines that experience a negative differential to NYMEX Henry Hub prices. If we are unable to secure firm pipeline transportation capacity on major pipelines that are in existence or under construction in our operating area to accommodate our growing production, it could have a material adverse effect on our financial condition and results of operations.

We currently do not have agreements with providers of gas gathering, processing or fractionation capacity with respect to our production from Our Marcellus Project Area, and we may not be able to enter into such agreements on favorable terms, or at all.

We have not entered into any gas gathering, processing or fractionation agreements with respect to our production from Our Marcellus Project Area. We may not be able to enter into any such agreements on favorable terms, or at all. Without such agreements, we may not receive priority service or capacity over third parties that utilize the same gas processing and fractionation plants and gas gathering systems. Our inability to obtain sufficient gas gathering, processing and fractionation capacity for our production from Our Marcellus Project Area could negatively impact our cash flows, financial condition and results of operations and reduce the overall value of our assets within this area.

Insufficient processing or takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas, NGLs and oil prices.

The Appalachian Basin natural gas business environment has historically been characterized by periods in which production has surpassed local takeaway capacity, resulting in substantial discounts in the price received by producers such as us. We expect that a significant portion of our production from the Utica Core Area and Our Marcellus Project Area will be transported on pipelines that may consistently or periodically experience a negative differential to NYMEX Henry Hub prices.

We do not currently have arrangements for firm pipeline transportation capacity for all of our expected production. If we are unable to secure additional gathering and compression capacity and long-term firm takeaway capacity on major pipelines that are in existence or currently under construction in our core operating area to accommodate our growing production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

Oil and condensate produced in the Appalachian Basin has increased substantially and is likely to continue to increase for the foreseeable future. There is limited takeaway capacity for these products and we anticipate sales of these products to occur at a discount to the benchmark WTI price. If we are unable to secure transportation for these products it could have a materials adverse effect on our financial condition and results of operations.

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We currently are and in the future expect to be party to contracts with third parties that include contractual minimums.

We are currently party to and expect to continue to be party to service contracts with drilling rig companies that require us to make shortfall payments to such companies if our actual activity level falls below specified contractual minimum activity levels. Moreover, in the future, we expect to enter into service contracts, such as firm pipeline transportation contracts with companies owning interstate pipelines, that may require us to make shortfall payments if our actual throughput falls below specified contractual minimum volumes. We can provide no assurance that our activity levels will be sufficient to satisfy the minimum requirements under our drilling rig contracts or that our future volumes will be sufficient to satisfy the minimum requirements under any such firm transportation contracts. If we fail to satisfy the minimum activity levels or throughput requirements associated with such contracts, we would be obligated to make shortfall payments to our counterparties based on the difference between our actual activity levels and throughput volumes, respectively, and the contract minimums in each case. These differences and the associated shortfall payments could be significant and we may not be able to generate sufficient cash to cover those obligations, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our revolving credit facility contains a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

incur additional indebtedness;

sell assets;

make loans to others;

make investments;

enter into joint ventures;

enter into mergers;

make payments, directly or indirectly, to purchase or otherwise retire our equity interests;

hedge future production or interest rates;

incur certain lease obligations;

incur liens;

modify the nature of our business or engage in international operations; and

pay dividends or make distributions.

The indenture governing our senior unsecured notes contains similar restrictive covenants. In addition, our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indenture governing our senior unsecured notes, may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our revolving credit facility and our indenture governing our senior unsecured notes impose on us.

A breach of any covenant in either our revolving credit facility or the indenture governing our senior unsecured notes would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived or cured, could result in acceleration of the indebtedness outstanding under the relevant agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt

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agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or obtain sufficient capital to refinance such indebtedness. Even if a refinancing were available, it may not be on terms that are acceptable to us. Moreover, an increased interest rate is also payable in connection with a default under our revolving credit facility and certain payment defaults under our senior unsecured notes.

Any significant reduction in our borrowing base or reduction of lender commitments under our revolving credit facility, as a result of the periodic borrowing base redeterminations or otherwise, may negatively impact our ability to fund our operations.

Our revolving credit facility limits the amounts we can borrow up to the lesser of a specified maximum borrowing base amount or the aggregate amount of lender commitments. The lenders, in their sole discretion, determine a borrowing base on a quarterly basis (until April 1, 2015, at which time such determinations will convert to a semi-annual basis) based upon the loan value assigned to the proved reserves attributable to our oil and gas properties evaluated in our most recent reserve report(s). Our lenders may further request two additional unscheduled borrowing base redeterminations during each calendar year. Any increase in the borrowing base requires the consent of the lenders holding 95.0% (or 100.0% if there are fewer than 3 lenders at the time of determination) of the commitments (provided that no lender's commitment may increase without its consent). Distinct from determinations of a borrowing base, each lender, in its sole discretion, determines the maximum amount of loans it will commit to make under the revolving credit facility based, in part, on general economic considerations and its prevailing lending policies. Outstanding borrowings in excess of the lesser of the specified maximum borrowing base amount or the prevailing aggregate lender commitment must be repaid. If we fail to repay such excess borrowings on a timely basis, we must provide additional oil and gas properties as collateral to the extent necessary to eliminate the deficiency. As of December 31, 2014, the borrowing base under our revolving credit facility was \$100.0 million and there were no outstanding borrowings and approximately \$26.9 million of outstanding letters of credit, resulting in borrowing availability of approximately \$73.1 million under our revolving credit facility.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in 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, without limitation, 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 our reserves.

In order to prepare reserve estimates, we must project production rates and 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.

Actual future production, natural gas and oil prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. As a substantial portion of our reserve estimates are made without the benefit of a lengthy production history, any significant variance from the above assumption could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

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Reserve estimates for plays, such as the Utica Core Area and Our Marcellus Project Area, where we predominately operate, that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. Less production history may contribute to less accurate estimates of reserves, future production rates and the timing of development expenditures. Most of our production is from wells that have been operational for less than one year, and as estimated reserves vary substantially from well to well, estimated reserves may not be correlated to perforated lateral length or completion technique. Furthermore, the lack of operational history for horizontal wells in the Utica Core Area and Our Marcellus Project Area may also contribute to the inaccuracy of future estimates of reserves and could result in our failing to achieve expected results in these plays. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates or management expectations would have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our gross identified drilling locations are scheduled out over many 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 capital that we expect to be necessary to drill our identified drilling locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas, NGLs and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, topographical constraints, lease expirations, the ability to form units, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, governmental regulation, the ability to pool or unitize our acreage with acreage leased to other operators and approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other identified drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. Further, some of the horizontal wells we intend to drill in the future may require unitization with adjacent leaseholds controlled by third parties. If these third parties are unwilling to unitize such leaseholds with ours, this may limit the total locations we can drill. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2014, after deducting wells that have been drilled or are in progress, we had identified approximately 3,112 gross (810 net) remaining drilling locations. As a result of the limitations described above, we may be unable to drill many of our identified drilling locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified drilling locations, see Business Our Properties.

We have acreage that we must commence operations upon before lease expiration in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on our oil and natural gas properties typically have a primary term of 5 years, after which they expire unless, prior to expiration, we commence operations within the spacing units covering the undeveloped acres. As of

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December 31, 2014, 2,336 gross (1,604 net) undeveloped acres scheduled to expire in 2015, 16,036 gross (4,721 net) undeveloped acres scheduled to expire in 2016, 41,693 gross (29,288 net) undeveloped acres scheduled to expire in 2017, and 34,082 gross (23,540 net) undeveloped acres scheduled to expire in 2018 and beyond. The cost to renew such leases may increase significantly, and we may not be able to renew such leases

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on commercially reasonable terms, or at all. Moreover, many of our leases require lessor consent to create units larger than the leases currently permit, which may make it more difficult to hold our leases by production or optimally develop our leasehold position. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases scheduled to expire in 2015, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy rigs when needed, or that commodity prices will warrant operating such a drilling program. Our reserves and future production, and therefore, our future cash flows and income, are highly dependent on successfully developing our undeveloped leasehold acreage and the loss of any leases could materially adversely affect our ability to so develop such acreage.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2012, December 31, 2013 and December 31, 2014, we based the discounted future net cash flows from our proved reserves on the 12-month first-day-of-the-month oil and natural gas average prices without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

actual prices we receive for natural gas, NGLs and oil;

actual cost of development and production expenditures;

the effect of derivative transactions;

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 proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure 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. As a limited partnership, Eclipse I, our predecessor, was not subject to federal taxation. Accordingly, our standardized measure for December 31, 2012 and December 31, 2013 does not provide for federal corporate income taxes because taxable income was passed through to our partners. As a corporation, we are treated as a taxable entity for federal income tax purposes, and our future income taxes are dependent on our future taxable income. 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 which could have a material effect on the value of our reserves.

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

Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due the long history of land ownership in the area, resulting in extensive and complex chains of title. In the course of acquiring the rights to develop oil and natural gas, it is standard procedure for us and the lessor to execute a lease agreement with payment subject to title verification. In most cases, we incur the expense of retaining lawyers, title abstractors or landmen to verify the rightful owners of the oil and gas interests prior to payment of such lease bonus to the lessor. There is no certainty, however, that a lessor has valid title to its lease's oil and gas interests. In those cases, such leases are generally voided and payment is not remitted to the lessor. As such, title failures may result in fewer net acres to us. Prior to the drilling of an oil or natural 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 title to the well. Frequently, as a result of such examinations, curative work must

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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 delay or prevent us from utilizing the associated mineral interest, which may adversely impact our ability in the future to increase production and reserves. Accordingly, 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 could suffer a financial loss or impairment of our assets.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2014, approximately 45% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 159.0 Bcfe of estimated proved undeveloped reserves will require an estimated \$274.6 million of development capital over the next 5 years. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the pre-tax 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 undeveloped reserves as unproved reserves.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write-downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. 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 properties. 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 results of operations for the periods in which such charges are taken.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we successfully conduct ongoing development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future oil and natural gas reserves and production, and therefore our future cash flows and results of operations, 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, find or acquire sufficient additional reserves to replace our current and future production. 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.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse

effect on our business, financial condition, results of operations and cash flows.

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

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas and oil, we may enter into derivative instrument contracts for a significant portion of our natural gas, NGLs and oil production, including fixed-price swaps, basis swaps, collars and firm sales agreements. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments 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 contractual obligations;

there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or

there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract. Any default by the counterparty to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

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

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables (\$20.7 million at December 31, 2014) and the sale of our natural gas and oil production (\$22.8 million in receivables at December 31, 2014). Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. For the year ended December 31, 2014, two customers, Antero Resources and Asset Risk Management, accounted for approximately 47% and 25%, respectively, of our revenues. We do not require 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.

Our operations are subject to governmental laws and regulations, which may expose us to significant costs and liabilities that could exceed current expectations.

Our operations are subject to various federal, state and local governmental regulations. Matters subject to regulation include wastewater disposal, the spacing of wells, unitization and pooling of properties and taxation. In addition, the production, handling, storage, transportation, remediation, emission and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations, primarily

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relating to protection of human health and the environment. Failure to comply with these laws, regulations and permits may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations, the imposition of stricter conditions on or revocation of permits, the issuance of injunctions limiting or preventing some or all of our operations, delays in granting permits and cancellation of leases. Moreover, these laws and regulations have continually imposed increasingly strict requirements for water and air pollution control and solid waste management. Significant expenditures may be required to comply with governmental laws and regulations applicable to us. We believe the trend of more expansive and stricter environmental legislation and regulations will continue for the foreseeable future. Please read Item 1. Business Regulation of the Oil and Natural Gas Industry and Item 1. Business Regulation of Environmental and Occupational Safety and Health Matters for a description of the laws and regulations that affect us.

We make assumptions and develop expectations about possible expenditures based on current laws and regulations and current interpretations of those laws and regulations. If the interpretation of laws or regulations, or the laws and regulations themselves, change, our assumptions may change, new capital costs may be incurred to comply with such changes. In addition, new laws and regulations might adversely affect our operations and activities, including drilling, processing, storage and transportation, as well as waste management and air emissions.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our business activities.

There is inherent risk of the incurrence of environmental costs and liabilities in our business, some of which may be material, due to the handling of our products as they are gathered, transported, processed and stored, air emissions related to our operations, historical industry operations, and water and waste disposal practices. Joint and several strict liability may be incurred without regard to fault under some environmental laws and regulations, including the Comprehensive Environmental Response, Compensation, and Liability Act, Resource Conservation and Recovery Act and analogous state laws, for the remediation of contaminated areas and in connection with spills or releases of natural gas, oil and wastes on, under, or from our properties and facilities. Private parties may 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 arising from our operations. Some sites at which we operate may be located near current or former third party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. In addition, increasingly strict laws, regulations and enforcement policies could materially increase our compliance costs and the cost of any remediation that may become necessary. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us.

We may be held responsible for all liabilities associated with the environmental condition of our facilities and assets, whether acquired or developed, regardless of when the liabilities arose and whether they are known or unknown. In connection with acquisitions and divestitures, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses, which may not be covered by insurance. In addition, the steps we could be required to take to bring facilities into compliance could be prohibitively expensive, and we might be required to shut down, divest or alter the operation of those facilities, which might cause us to incur losses.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water and disposal options. Restrictions on the ability to obtain water or dispose of wastewater may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our

exploration and production operations, could adversely impact our operations.

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Moreover, the imposition of new environmental initiatives and regulations could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Clean Water Act, or the CWA, imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. The EPA has also adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

We are subject to risks associated with climate change.

In recent years, federal, state and local governments have taken steps to reduce emissions of greenhouse gases, or GHGs. The EPA has finalized a series of GHG monitoring, reporting and emissions control rules for oil and natural gas industry, and the U.S. Congress has, from time to time, considered adopting legislation to reduce emissions. Almost one-half of the states have already taken measures to reduce emissions of GHGs primarily through the development of GHG emission inventories and/or regional GHG cap-and-trade programs. While we are subject to certain federal GHG monitoring and reporting requirements, our operations currently are not adversely impacted by existing federal, state and local climate change initiatives.

The costs that may be associated with the impacts of climate change and the regulation of GHGs have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services, and the demand for and consumption of our products and services (due to changes in both costs and weather patterns). If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. To the extent financial markets view climate change and GHG emissions as a financial risk, this could negatively impact our cost of and access to capital. At this time, however, it is not possible to estimate how future laws or regulations or climatic changes may impact our business.

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.

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 uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline or river contamination;

abnormally pressured formations;

mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;

fires, explosions and ruptures of pipelines or processing facilities;

personal injuries and death;

natural disasters; and

terrorist (including eco-terrorist) attacks targeting natural gas and oil related facilities and infrastructure.

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

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.

In accordance with what we believe to be customary industry practice, we maintain insurance against some, but not all, of our business risks. Our insurance may not be adequate to cover any or all of the losses or liabilities we may suffer. Also, insurance may no longer be available to us or, if it is, its availability may be at premium levels that do not justify its purchase. The occurrence of a significant uninsured claim, a claim in excess of the insurance coverage limits maintained by us or a claim at a time when we are not able to obtain liability insurance could have a material adverse effect on our ability to conduct normal business operations and on our financial condition, results of operations or cash flows. In addition, we may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial condition. We may also be liable for environmental damage caused by previous owners of properties purchased by us, which liabilities may not be covered by insurance.

Since hydraulic fracturing activities are a large part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean-up costs stemming from a sudden and accidental pollution event. However, we may not have coverage if we are unaware of the pollution event and unable to report the occurrence to our insurance company within the time frame required under our insurance policy. We have no coverage for gradual, long-term pollution events. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial condition, results of operations and cash flows.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

We have made asset and business acquisitions in the past and we may continue to make acquisitions of assets or businesses in the future that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition depends on our ability to integrate the acquired business effectively into our existing operations. The process of integrating acquired businesses may involve difficulties that require a disproportionate amount of our managerial and financial resources to resolve. For example, we acquired Oxford in June 2013, and following the completion of the acquisition, we have dedicated significant managerial and financial resources to update the informal and incomplete legal, financial, accounting and business records previously in place at Oxford to substantiate transactions undertaken by Oxford prior to the acquisition. In addition, we have expended significant resources, including the time and attention of our management team, on integrating Oxford's pre-existing operations, personnel and assets into our business plan.

In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate successfully the

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acquired businesses and assets into our existing operations or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our revolving credit facility and the indenture governing our senior unsecured notes impose certain limitations on our ability to enter into mergers or combination transactions and to make investments. Our revolving credit facility and the indenture governing our senior unsecured notes also limit our ability to incur certain indebtedness and liens, which could limit our ability to engage in acquisitions of businesses.

We may be subject to risks in connection with acquisitions of properties.

We have historically acquired assets and businesses that we feel complement our assets and business and may continue to do so in the future. The successful acquisition of producing properties requires an assessment of several factors, including:

recoverable reserves;

future natural gas, NGLs or oil prices and their applicable differentials;

operating costs; and

potential environmental 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 capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, 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 and acquire properties on an as is basis.

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

Market conditions or the unavailability of satisfactory natural gas, NGLs or oil transportation arrangements may hinder our access to markets or delay our production. The availability of a ready market for our production depends on a number of factors, including the demand for and supply of natural gas, NGLs or oil 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. Because many of our operations are in an emerging play, much of this infrastructure is currently being built or is yet to be built, and we cannot assure you that it will be built on time or at all. Our failure to obtain such services on acceptable terms and concurrent with the completion of our wells could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs or oil pipeline or gathering system capacity. In addition, if quality specifications for the third party pipelines with which we connect change so as to

restrict our ability to transport product, our access to markets could be impeded. 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 unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Some of the rigs performing work for us do so on a well-by-well basis and can refuse to provide such services at the conclusion of drilling on the current well. Historically, there have been shortages of drilling and workover rigs, pipe and other

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equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay 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.

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

Our ability to acquire additional prospects 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 natural gas, NGLs and oil and securing 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 natural gas and oil properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other 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 three 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 past success of our senior management with developing public natural gas and oil enterprises, and the expertise of our senior management in the acquisition, exploration and development of unconventional natural gas and oil properties does not guarantee our success or profitability.

As described in this Annual Report on Form 10-K, most of our executive officers and other key personnel, including our Chairman, President and Chief Executive Officer, Benjamin W. Hulburt, our Executive Vice President and Chief Operating Officer, Thomas S. Liberatore, and our Executive Vice President, Secretary and General Counsel, Christopher K. Hulburt, have substantial past experience in the acquisition, exploration and development of unconventional natural gas and oil properties, including experience at Rex Energy Corporation, Cabot Oil & Gas Corporation, Chesapeake Energy Corporation and Stone Energy Corporation. See Item 10. Directors, Executive Officers and Corporate Governance. However, the past experience and success of our executive officers and other key personnel with respect to previous endeavors in the natural gas and oil industry is not a guarantee of our future success or profitability.

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

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including Benjamin W. Hulburt, our Chairman, President and Chief Executive Officer, Matthew R. DeNezza, our Executive Vice President and Chief Financial Officer, Thomas Liberatore, our Executive Vice President and Chief Operating Officer, and Christopher K. Hulburt, our Executive Vice President, Secretary and General Counsel, could have a material adverse effect on our business, financial condition and results of operations.

We are susceptible to the potential difficulties associated with rapid growth and expansion.

We have grown rapidly since our inception in January 2011, including through the acquisition of Oxford in 2013. Our management team believes that our future success depends on our ability to manage the rapid growth that we have

experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

increased responsibilities for our executive level personnel;

increased administrative burden;

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increased capital requirements; and

increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties.

Seasonal weather conditions and regulations intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in the areas where we operate.

Natural gas and oil operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect certain species of wildlife. For example, we must comply with state and federal regulations aimed at protecting the Indiana bat (*Myotis soldalis*), which has been listed as an endangered species by both federal and state law, and those regulations restrict or increase the cost of our operations by, among other things, limiting our ability to clear trees to establish rights of way or pad locations on some of our acreage during certain periods of the year. See Business Regulation of Environmental and Occupational Safety and Health Matters Endangered Species Act and Migratory Bird Treaty Act. Adverse seasonal weather conditions and wildlife regulations may limit our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs. In addition, the designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration, development and production activities.

Acts of terrorism (including eco-terrorism) could have a material adverse effect on our financial condition, results of operations and cash flows.

Our assets and operations, and the assets and operations of our providers of gas gathering, processing, transportation and fractionation services, may be targets of terrorist activities (including eco-terrorist activities) that could disrupt our business or cause significant harm to our operations, such as full or partial disruption to our ability to produce, process, transport, market or distribute natural gas, NGLs and oil. Acts of terrorism, as well as events occurring in response to or in connection with acts of terrorism, could cause environmental and other repercussions that could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our financial condition, results of operations and cash flows. In addition, acts of terrorism, and the threat of such acts, could result in volatility in the prices for natural gas, NGLs and oil and could affect the markets for such commodities.

Increases in interest rates could adversely affect our business.

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

The enactment of derivatives legislation, and the promulgation of regulations pursuant thereto, could have an adverse effect on our ability to use derivative instruments to hedge risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was enacted on July 21, 2010 and 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 Commodity Futures Trading

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Commission, or the CFTC, and the SEC to promulgate certain rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized some regulations, including critical rulemakings on the definition of swap, swap dealer, and major swap participant, others remain to be finalized and it is not possible at this time to predict when this will be accomplished.

The Dodd-Frank Act authorized the CFTC to establish rules and regulations setting position limits for certain futures and option contracts, including in the major energy markets and for the first time for swaps that are their economic equivalents. The CFTC's initial position limit rules under the Dodd-Frank Act were vacated by the U.S. District Court for the District of Columbia in September 2012 before such rules took effect. However, on November 5, 2013, the CFTC proposed new rules that would place limits on positions in certain core futures, options and equivalent swaps contracts in certain physical commodities, subject to exceptions for certain bona fide hedging and other transactions. The proposed new position limit rules also included requirements for aggregating positions in determining compliance limits. As these new position limit rules are not yet final, the impact of those provisions on our use of derivatives for which federal position limits do currently exist is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and execution on certain trading platforms. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing or trade execution. Although we expect to qualify for the end-user exception from the mandatory clearing and trade execution requirements for swaps entered to hedge its commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce our cash available for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The margin rules are not yet final, and therefore the impact of those provisions to us is uncertain at this time.

The Dodd-Frank Act and regulations may also require or cause 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, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. 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 and regulations is lower commodity prices.

Any of these consequences could have a material adverse effect on us, our financial condition or our results of operations.

Proposed changes to U.S. and state tax laws, if adopted, could have an adverse effect on our business, financial condition, results of operations and cash flows.

The U.S. President's Fiscal Year 2015 Revenue Proposals include provisions that would, if enacted, make significant changes to U.S. tax laws, and legislation has been introduced recently in Congress that would implement some of

these proposals. These changes include, but are not limited to, eliminating the immediate deduction for intangible drilling and development costs, eliminating the deduction from income for domestic production activities relating to oil and natural gas exploration and development, repealing the percentage

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depletion allowance for oil and natural gas properties and extending the amortization period for certain geological and geophysical expenditures. These proposed changes in the U.S. tax laws, if adopted, or other similar changes that reduce or eliminate deductions currently available with respect to oil and natural gas exploration and development, could adversely affect our business, financial condition, results of operations and cash flows.

In February 2013, the governor of the State of Ohio proposed a plan to enact new severance taxes in fiscal 2014 and 2015. However, the Ohio State Senate did not include a severance tax increase in the version of the budget bill that it passed on June 7, 2013. On May 14, 2014, the Ohio House of Representatives passed a measure (H.B. 375) that imposes a tax of 2.5% on the gross receipts received for oil and gas severed from a horizontal well on or after October 1, 2014. This measure replaces the existing tax based on volume. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates, if such legislation is enacted.

Risks Related to Our Common Stock

We are a controlled company within the meaning of the NYSE rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements. As a result, our stockholders do not have the same protections afforded to stockholders of companies that are subject to such requirements.

Eclipse Holdings, which is owned by the EnCap Funds, the Management Funds and Management Holdco, beneficially owns a majority of our common stock. We have entered into a stockholders' agreement with Eclipse Holdings and its limited partners, the EnCap Funds, the Management Funds and Management Holdco, pursuant to which such stockholders have certain rights relative to designated director nominees and agreed to vote their shares of common stock in accordance with the stockholders' agreement, including as it relates to the election of directors. For additional information regarding the stockholders' agreement, please read Certain Relationships and Related Party Transactions Stockholders Agreement. As a result, we are a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

a majority of our board of directors consist of independent directors;

we have a nominating and governance committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and

we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

We are currently utilizing, and intend to continue to utilize, the exemption relating to the nominating and governance committee, and we may utilize this exemption for so long as we are a controlled company. Accordingly, our stockholders do not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. See Item 10. Directors, Executive Officers and Corporate Governance.

Eclipse Holdings, which is owned by the EnCap Funds, the Management Funds and Management Holdco, holds a substantial majority of our common stock.

Eclipse Holdings, which is owned by the EnCap Funds, the Management Funds and Management Holdco, holds the majority of the outstanding shares of our common stock. Eclipse Holdings is entitled to act separately in its own interest with respect to its shares of our common stock, and it has the voting power to elect all of the members of our board of directors and thereby control our management and affairs. In addition, Eclipse Holdings has the ability to determine the outcome of all matters requiring stockholder approval, including mergers and other material transactions, and to cause or prevent a change in the composition of our board of directors or a change in control of our company that could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company. The existence of a significant stockholder may

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also have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company.

So long as Eclipse Holdings continues to control a significant amount of our common stock, Eclipse Holdings and its limited partners will continue to be able to strongly influence all matters requiring stockholder approval, regardless of whether or not other stockholders believe that a potential transaction is in their own best interests. In any of these matters, the interests of Eclipse Holdings and its limited partners may differ or conflict with the interests of our other stockholders. Moreover, this concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a controlling stockholder.

The stockholders agreement we entered into in connection with the completion of our IPO permit our principal stockholders to designate a majority of the members of our board of directors.

In connection with the completion of our IPO, we entered into a stockholders agreement with Eclipse Holdings and its limited partners, the EnCap Funds, the Management Funds and Management Holdco, which we refer to as our principal stockholders, pursuant to which such stockholders were provided with certain rights relative to designated director nominees and agreed to vote their shares of common stock in accordance with the stockholders agreement, including as it relates to the election of directors. See Item 13. Certain Relationships and Related Transactions and Director Independence. Certain of our directors and members of our management team control or have other relationships with our principal stockholders. See Item 13. Certain Relationships and Related Transactions and Director Independence.

Conflicts of interest could arise in the future between us, on the one hand, and EnCap and its affiliates, including its portfolio companies, on the other hand, concerning, among other things, potential competitive business activities or business opportunities.

EnCap is a leading provider of private equity to the independent sector of the U.S. oil and gas industry and manages investment funds with ownership interests in Eclipse Holdings. EnCap and its affiliates may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. EnCap and its affiliates may acquire or seek to acquire assets that we seek to acquire, and as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue. Moreover, EnCap has an interest in Caiman Energy II, LLC, which owns a significant interest in Blue Racer, a provider of firm gathering, processing and fractionation capacity for our operated acreage in the Rich Gas, Condensate and Rich Condensate Windows of the Utica Core Area. As a result, EnCap's interests with respect to matters arising in connection with our arrangements with Blue Racer may not align with our interests. Any actual or perceived conflicts of interest with respect to the foregoing could have an adverse impact on the trading price of our common stock.

The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the Exchange Act), and the requirements of the Sarbanes Oxley Act of 2002 (the Sarbanes Oxley Act), may strain our resources, increase our costs and distract management.

We completed our IPO in June 2014. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. These rules and regulations

have increased our legal and financial compliance costs and make some activities more time-consuming and costly. These rules and regulations also make it more difficult and more expensive for us to obtain director and officer liability insurance. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

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If we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes-Oxley Act. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our shares of common stock.

The price of our common stock may fluctuate significantly and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

our operating and financial performance and drilling locations, including reserve estimates;

quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;

the public reaction to our press releases, our other public announcements and our filings with the SEC;

strategic actions by our competitors;

our failure to meet revenue, reserves or earnings estimates;

changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;

speculation in the press or investment community;

the failure of research analysts to cover our common stock;

sales of our common stock by us, Eclipse Holdings, the selling stockholders or other stockholders, or the perception that such sales may occur;

changes in accounting principles, policies, guidance, interpretations or standards;

additions or departures of key management personnel;

actions by our stockholders;

general market conditions, including fluctuations in commodity prices;

domestic and international economic, legal and regulatory factors unrelated to our performance; and

the realization of any risks describes under this Risk Factors section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and harm our business, operating results and financial condition.

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Future sales of our common stock could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute our stockholders' ownership in us.

We may sell additional shares of common stock in subsequent public or private offerings. We may also issue additional shares of common stock or convertible securities. As of December 31, 2014, we had 160,031,115 outstanding shares of common stock. Eclipse Holdings owns 129,700,000 shares of our common stock, or approximately 81% of our total outstanding shares, all of which are restricted from immediate resale under the federal securities laws, but may be sold into the market in the future. Subject to compliance with the Securities Act or exemptions therefrom, certain of our employees may sell their shares of common stock into the public market.

Subject to the satisfaction of vesting conditions and the requirements of Rule 144, shares registered under our registration statement on Form S-8 filed on July 2, 2014 relating to our equity incentive plan are available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

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;

limitations on the ability of our stockholders to call special meetings;

providing that the board of directors is expressly authorized to adopt, or to alter or repeal our amended and restated bylaws; and

establishing advance notice and information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Our amended and restated certificate of incorporation designates the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers or other employees.

Our amended and restated certificate of incorporation provides that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware shall be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law, or (iv) any action asserting a claim against us governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in shares of our common stock shall be deemed to have notice of and consented to the provisions of our amended and restated certificate of incorporation described above. This choice of forum

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provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or other employees, which may discourage such lawsuits against us and our directors, officers and other employees. Alternatively, if a court were to find these provisions of our amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

We do not intend to pay cash dividends on our common stock, and our revolving credit facility and the indenture governing our senior unsecured notes place certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare cash dividends on shares of our common stock in the foreseeable future. Additionally, our revolving credit facility and the indenture governing our senior unsecured notes place certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it.

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

We are classified as an emerging growth company under the JOBS Act. For as long as we are an emerging growth company, which may be up to 5 full fiscal years, unlike other public companies, we will not be required to, among other things, (1) provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404(b) of the Sarbanes-Oxley Act, (2) comply with any new requirements adopted by the Public Company Accounting Oversight Board requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer, (3) provide certain disclosure regarding executive compensation required of larger public companies or (4) hold nonbinding advisory votes on executive compensation. We will remain an emerging growth company for up to 5 years, although we will lose that status sooner if we have more than \$1.0 billion of revenues in a fiscal year, have more than \$700.0 million in market value of our common stock held by non-affiliates, or issue more than \$1.0 billion of non-convertible debt over a 3-year period.

We may issue preferred stock whose terms could adversely affect the voting power or value of our common stock.

Our amended and restated certificate of incorporation authorizes us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of our common stock.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock is influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn

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could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

Information regarding the Company's legal proceedings is set forth in Note 13 *Commitments and Contingencies*, located in the Notes to the Consolidated Financial Statements included in Part II Item 8. of this Annual Report on Form 10-K and is incorporated herein by reference.

Item 4. Mine Safety Disclosures

Not applicable.

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We have one class of common shares outstanding, our par value \$0.01 per share Common Stock (Common Stock). Our Common Stock is traded on the New York Stock Exchange under the symbol ECR . As of February 9, 2015 our Common Stock was held by 10 holders of record. The number of holders does not include the shareholders for whom shares are held in a nominee or street name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange from June 20, 2014, the date the shares were first traded, through December 31, 2014.

	Sales Prices	
	High	Low
2014		
First Quarter	\$ N/A	\$ N/A
Second Quarter	\$ 27.18	\$ 24.27
Third Quarter	\$ 25.33	\$ 15.85
Fourth Quarter	\$ 16.80	\$ 5.18

Use of Proceeds

On June 25, 2014, we completed our initial public offering (IPO) of 30,300,000 shares of our common stock, which included 21,500,000 shares sold by us and 8,800,000 shares sold by certain of our selling stockholders. Our net proceeds from our IPO were approximately \$544.7 million, after deducting underwriting discounts and commissions and the offering expenses payable by us of approximately \$35.8 million. We used a portion of the net proceeds we received from our IPO to repay the then-outstanding borrowings under Eclipse I's revolving credit facility, and used the remainder of such proceeds to fund our capital expenditure plan.

Dividend Policy

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, certain of our debt instruments place restrictions on our ability to pay cash dividends.

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Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of \$100 on June 20, 2014, the first date on which our common stock was publicly traded, in each of Eclipse Resources Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration & Production Index.

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The following table shows the selected historical consolidated financial data of Eclipse Resources Corporation and subsidiaries for the periods and as of the dates indicated. Our historical results are not necessarily indicative of future operating results. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations and our consolidated financial statements and related notes included in Item 8. Financial Statements and Supplementary Data.

The selected historical consolidated financial data as of and for the years ended December 31, 2014, 2013 and 2012 are derived from the audited consolidated financial statements of Eclipse Resources Corporation.

Statement of Operations data:	Year Ended December 31,		
(in thousands, except per share data)	2014	2013	2012
REVENUES			
Oil and natural gas sales	\$ 137,816	\$ 12,935	\$ 370
Total revenues	137,816	12,935	370
OPERATING EXPENSES			
Lease operating	8,518	2,576	16
Transportation, gathering and compression	18,114	67	
Production and ad valorem taxes	7,084	77	1
Depreciation, depletion and amortization	89,218	6,163	404
Exploration	21,186	3,022	4,692
General and administrative	45,392	21,276	4,425
Accretion of asset retirement obligations	791	364	
Impairment of proved oil and gas properties	34,855	2,081	
Gain on sale of properties	(960)		(372)
Gain on reduction of pension liability	(2,208)		
Total operating expenses	221,990	35,626	9,166
OPERATING LOSS	(84,174)	(22,691)	(8,796)
OTHER INCOME (EXPENSE)			
Gain on derivative instruments	20,791		
Interest expense, net	(48,347)	(20,850)	37
Other income	353		
Total other expense, net	(27,203)	(20,850)	37
LOSS BEFORE INCOME TAXES	(111,377)	(43,541)	(8,759)
INCOME TAX EXPENSE	71,799		
NET LOSS	\$ (183,176)	\$ (43,541)	\$ (8,759)

Statement of Cash Flow data:

Net cash provided by (used in)

Operating activities	\$ 23,266	\$ 15,250	\$ (3,381)
Investing activities	(733,189)	(897,086)	(47,535)
Financing activities	667,931	964,288	68,916

Balance Sheet data:

Cash and cash equivalents	\$ 67,517	\$ 109,509	\$ 27,057
Total property and equipment, net	1,722,827	1,018,084	106,253
Total assets	1,884,946	1,143,523	133,522
Total debt	414,016	389,247	
Total stockholders' equity	1,152,711	667,971	126,704

Other financial data:

Adjusted EBITDAX	\$ 62,426	\$ (11,018)	\$ (4,069)
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Adjusted EBITDAX is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; DD&A; amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments on settled derivative instruments, and premiums (paid) received on options that settled during the period:) non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with U.S. GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with U.S. GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and

is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our Revolving Credit Facility and the Indentures.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net loss from operations to Adjusted EBITDAX for the periods presented:

	2014	2013	2012
Net loss	\$ (183,176)	\$ (43,541)	\$ (8,759)
Depreciation, depletion & amortization	89,218	6,163	404
Exploration expense	21,186	3,022	4,692
Rig termination expenses	3,283		
Incentive unit compensation	256	43	3
Accretion of asset retirement obligations	791	364	

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Impairment of proved oil and gas properties	34,855	2,081	
Gain on reduction of pension obligations	(2,208)		
Gain on derivative instruments	(20,791)		
Net cash receipt (payment) on derivative instruments	564		
Net cash paid for option premium	(385)		
Interest expense	48,347	20,850	(37)
Gain on sale of assets	(960)		(372)
Gain on acquisition of business	(353)		
Income tax expense	71,799		
Adjusted EBITDAX	\$ 62,426	\$ (11,018)	\$ (4,069)

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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. 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 natural gas, NGLs and oil 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, 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, 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 Statement Regarding Forward-Looking Statements. Also, see the risk factors and other cautionary statements described in Item 1A. Risk Factors of this Annual Report. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

On June 24, 2014, prior to the closing of our initial public offering (IPO) we completed our Corporate Reorganization, as described under Note 1 Organization and Nature of Operations . As such, information presented in Management's Discussion and Analysis of Financial Condition and Results of Operations for the period from January 1, 2014 through June 23, 2014, as contained within the year ended December 31, 2014, and for the years ended December 31, 2013 and 2012, pertain to the historical financial statements and results of operations of Eclipse I, our accounting predecessor.

Overview of Our Business

We are an independent exploration and production company engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin. We are focused on creating stockholder value by developing our substantial inventory of horizontal drilling locations, continuing to opportunistically add to our acreage position where we can acquire assets at attractive prices and leveraging our technical and managerial expertise to deliver industry-leading results.

Approximately 100,700 of our net acres are located in the Utica Shale fairway, which we refer to as the Utica Core Area, and approximately 27,250 of these net acres are also prospective for the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as Our Marcellus Project Area. We are the operator of approximately 85% of our net acreage within the Utica Core Area and Our Marcellus Project Area. We began assembling our acreage position in 2011 based upon a rigorous analytical evaluation of the shale properties within the Utica and Point Pleasant formations across Eastern Ohio. We initially targeted and acquired approximately 27,000 net acres in the Utica Core Area in 2011 through a combination of leasing and largely contiguous acreage acquisitions. In 2012, we entered into an agreement with Antero Resources to form an area of mutual interest covering approximately 43,600 gross acres predominately in Noble County, Ohio, which Antero Resources operates. Pursuant to our agreement, during a three-year term, we and Antero Resources have the option to purchase an interest in any acquisitions of oil and gas interests the other completes within the area of mutual interest. If the non-acquiring party elects to participate, we will own an undivided 30% interest and Antero Resources will own an undivided 70% interest in such acquired oil and gas interests. In June 2013, we acquired Oxford, which held approximately 180,000 net acres in Ohio, including approximately 49,000 net acres in the Utica Core Area and approximately 1,289 gross proved producing conventional wells.

Since entering the Utica Shale play in May 2011, through December 31, 2014, we, or our operating partners, had commenced drilling 183 gross (73.1 net) wells within the Utica Core Area and Our Marcellus Project Area,

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of which 32 gross (14.1 net) were drilling, 31 gross (15.1 net) were awaiting completion, 6 gross (1.8 net) were in the process of being completed, 14 gross (8.5 net) were awaiting midstream and 100 gross (33.6 net) had been turned to sales.

As of December 31, 2014, we:

were operating 3 horizontal rigs in the Utica Core Area;

had identified 3,112 gross (810 net) horizontal drilling locations across our acreage, comprised of 2,541 gross (605 net) locations within the Utica Core Area and 571 gross (205 net) locations within Our Marcellus Project Area;

had average daily production for the year ended December 31, 2014 of approximately 72.7 MMcfe comprised of approximately 75% natural gas, 12% NGLs and 13% oil; and

our estimated proved reserves were 355.8 Bcfe, or 59.3 MMBoe, based on reserve reports prepared by Netherland, Sewell & Associates, Inc., or NSAI, our independent petroleum engineers, all of which were in Ohio and approximately 55% of which were proved developed reserves. Our estimated proved reserves were approximately 72% natural gas, 18% NGLs and 10% oil, as of December 31, 2014.

Factors That Significantly Affect Our Financial Condition and Results of Operations

We derive substantially all of our revenues from the production and sale of natural gas, NGLs and oil that are extracted from our natural gas during processing. During the year ended December 31, 2014, our revenues were comprised of approximately 50.4%, 15.3% and 34.3% from the production and sale of natural gas, NGLs and oil, respectively. Our revenues, cash flow from operations and future growth depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Natural gas, NGLs and oil prices have historically been volatile and may fluctuate widely in the future due to a variety of factors, including, but not limited to, prevailing economic conditions, supply and demand of hydrocarbons in the marketplace and geopolitical events such as wars or natural disasters. Sustained periods of low prices for these commodities would materially and adversely affect our financial condition, our results of operations, the quantities of natural gas, NGLs and oil that we can economically produce and our ability to access capital.

In January 2014, we began using commodity derivative instruments to manage and reduce price volatility and other market risks associated with our production. These arrangements are structured to reduce our exposure to commodity price decreases, but they can also limit the benefit we might otherwise receive from commodity price increases. Our risk management activity is generally accomplished through over-the-counter commodity derivative contracts with large financial institutions. We currently use a mix of natural gas fixed price swaps, basis swaps and put option spreads and collars. Swaps are settled monthly based on differences between the fixed price specified in the contract and the referenced settlement price. When the referenced settlement price is less than the price specified in the contract, we receive a settlement from the counterparty based on the price difference multiplied by the volume. Similarly, when the referenced settlement price exceeds the price specified in the contract, we pay the counterparty an amount based on the price difference multiplied by the volume. A put option spread is the combination of a purchased put and a sold put. The purchased put establishes the minimum price that we will receive for the contracted volumes

unless the referenced price falls below the sold put strike price, at which point the minimum price equals the reference price plus the excess of the purchased put strike price over the sold put strike price. Collars establish a minimum floor price and a predetermined ceiling price. The prices contained in these derivative contracts are based on NYMEX Henry Hub prices. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. The actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of location differentials. Location differentials to NYMEX Henry Hub prices, also known as basis differential, result from variances in regional natural gas prices compared to NYMEX Henry Hub prices as a result of regional supply and demand factors. In July 2014, we began hedging basis differentials associated with our

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natural gas production. We have elected not to designate our current portfolio of commodity derivative contracts as hedges for accounting purposes. Therefore, changes in fair value of these derivative instruments are recognized in earnings in the period of change. Please read Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional discussion of our commodity derivative contracts.

Like other businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from a given well naturally decreases. Thus, an exploration and production company depletes part of its asset base with each unit of reserves it produces. We attempt to overcome this natural decline by drilling to find additional reserves and acquiring more reserves than we produce. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production in a cost effective manner. Our ability to make capital expenditures to increase production from our existing reserves and to add reserves through drilling is dependent on our capital resources and can be limited by many factors, including our ability to access capital in a cost effective manner and to timely obtain drilling permits and regulatory approvals.

Our financial condition and results of operations, including the growth of production, cash flows and reserves, are driven by several factors, including:

success in drilling new wells;

natural gas, NGLs and oil prices;

the availability of attractive acquisition opportunities and our ability to execute them;

the amount of capital we invest in the leasing and development of our properties;

facility or equipment availability and unexpected downtime;

delays imposed by or resulting from compliance with regulatory requirements; and

the rate at which production volumes on our wells naturally decline.

Factors That Significantly Affect Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

Public Company Expenses. As a result of our IPO, we expect to incur direct incremental general and administrative (G&A) expenses as a result of being a publicly traded company, including, but not limited to, costs associated with annual and quarterly reports and our other filings with the SEC, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs

and independent director compensation.

Corporate Reorganization. Information presented in Management's Discussion and Analysis of Financial Condition and Results of Operations for the period from January 1, 2014 through June 23, 2014, as contained within the year ended December 31, 2014, and for the years ended December 31, 2013 and 2012 pertain to the historical financial statements and results of operations of Eclipse I, our accounting predecessor. As a result, the historical financial data may not give you an accurate indication of what our actual results would have been had our Corporate Reorganization been completed at the beginning of the periods presented or of what our future results of operations are likely to be.

The Oxford Acquisition. We acquired Oxford on June 26, 2013. As such, the results of Oxford's operations prior to such date are not included in the historical financial statements of Eclipse I that are presented within this Annual Report. Accordingly, our historical financial data may not present an accurate indication of what our actual results would have been if the Oxford Acquisition had been completed at the beginning of the periods presented or of what our future results of operations are likely to be.

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Income Taxes. We recognized income tax expense of approximately \$71.8 million for the year ended December 31, 2014. We were not a tax paying entity prior to the completion of our Corporate Reorganization on June 24, 2014 and therefore, no income tax expense was recorded by us prior to such time. Income tax expense for the year ended December 31, 2014 is made up of two elements: (i) the change in tax status charge, and (ii) income tax benefit from continuing operations.

With the consummation of our Corporate Reorganization on June 24, 2014 prior to our IPO, we became a tax paying entity, and as such, were required to record a charge against income equal to the estimated tax effect of the excess of the book carrying value of our net assets (primarily producing oil and gas properties) over their collective estimated tax basis as of the closing date of the Corporate Reorganization. As a result, we recorded a tax expense of approximately \$97.6 million.

For the year ended December 31, 2014, we had an income tax benefit from continuing operations of \$25.8 million. This represents an application of our annual effective tax rate (including state income taxes) for 2014 to our income subject to corporate tax earned from the Corporate Reorganization date through December 31, 2014. Please see Note 14 *Income Tax* located in the Notes to the Consolidated Financial Statements included in Item 8 of Part II of this Annual Report on Form 10-K.

Increased Horizontal Drilling Activity. We began horizontal, unconventional drilling operations in 2012, and through December 31, 2014, we, or our operating partners, had commenced drilling 183 gross (73.1 net) wells. Our current and future drilling activity is substantially weighted towards the development of our Utica and Marcellus Shale acreage using horizontal wells. The costs and production associated with the wells we expect to drill in the Utica and Marcellus Shale will differ substantially from the vertical conventional wells historically drilled.

Financing Arrangements. As of December 31, 2014, we had outstanding indebtedness, excluding debt discount, of \$422.5 million. In June 2013, we issued \$300.0 million in aggregate principle amount of 12.0% senior unsecured PIK notes due 2018, which we refer to as our Senior Unsecured Notes. In December 2013, we issued an additional \$100.0 million of Senior Unsecured Notes at par. We elected to settle our accrued interest payable on January 15, 2014 by issuing PIK securities of \$22.5 million. The Company exercised its option to settle its accrued interest payable due on January 15, 2015 by paying cash of \$12.7 million and by issuing PIK securities of \$14.8 million.

Cumulative net proceeds from our Senior Unsecured Notes of \$380.7 million, after offering fees and expenses, were used along with contributions from private equity funds managed by EnCap and investment funds controlled by certain members of our management team to acquire Oxford and to continue to develop our acreage in the Utica Core Area and in Our Marcellus Project Area.

On February 18, 2014, we entered into a \$500.0 million senior secured revolving credit facility, which was amended and restated on January 12, 2015, and which matures on January 15, 2018 and includes customary affirmative and negative covenants. At December 31, 2014, the borrowing base was \$100 million and the Company had no outstanding borrowings. After considering outstanding letters of credit issued by the Company, totaling \$26.9 million, we had available capacity on our Revolving Credit Facility of \$73.1 million at December 31, 2014. In March 2015, we had a redetermination of the borrowing base under our Revolving Credit Facility, which increased the borrowing base to \$125 million.

On December 27, 2014, we entered into a Securities Purchase Agreement with the EnCap Funds, the Management Funds and the other stockholders pursuant to which we agreed to issue and sell to such purchasers an aggregate of 62,500,000 shares of common stock at a price of \$7.04 per share pursuant to the exemptions from registration provided in Rule 506 of Regulation D promulgated under Section 4(2) of the Securities Act, such transaction referred

to herein as the private placement.

On January 28, 2015, we closed the private placement and received net proceeds from the issuance of the shares to the purchasers of approximately \$434 million (after deducting placement agent commissions and our estimated expenses), which we intend to use to fund our capital expenditure plan and for general corporate

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purposes. Upon the closing of the private placement, we amended and restated the existing registration rights agreement that we entered into upon the closing of our IPO to give the stockholders certain registration rights with respect to the stock purchased in the private placement. Please see [Recent Developments Amended and Restated Revolving Credit Facility](#) for more information.

Prior to our Corporate Reorganization, our capital expenditures were financed with capital contributions from private equity funds managed by EnCap and investment funds controlled by certain members of our management team, net proceeds from the issuance of our Senior Unsecured Notes and net cash provided by operating activities. In the future, we may incur additional indebtedness or issue additional equity securities to fund our acquisition and development activities. Please read [Credit Arrangements](#) for additional discussion of our financing arrangements.

Source of Our Revenues

Our historical revenues are derived from the sale of natural gas, NGLs and oil, and do not include the effects of derivatives. Revenues from product sales are a function of the volumes produced, prevailing market prices, product quality, gas Btu content and transportation costs. We generally sell production at a specific delivery point, pay transportation costs to a third party and receive proceeds from the purchaser with no transportation deduction. We record transportation costs as transportation, gathering and compression expense. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Principal Components of Our Cost Structure

Lease operating. These are day-to-day costs incurred to bring hydrocarbons out of the ground along with the daily costs incurred to maintain our producing properties. Such costs include compensation of our field employees, maintenance, repairs and workovers expenses related to our natural gas and oil properties. These costs are expected to remain a function of supply and demand.

Transportation, gathering and compression. Under some of our sales arrangements, we sell natural gas at a specific delivery point, pay transportation, gathering and compression costs to a third party and receive proceeds from the purchaser with no deduction. These costs represent those transportation, gathering and compression costs paid by us to third parties. Additionally, we plan to enter multiple firm transportation contracts that secure takeaway capacity that includes minimum volume commitments, the cost of which is included in these expenses.

Production and ad valorem taxes. Production taxes are paid on produced natural gas and oil based on a percentage of market prices or at fixed rates established by the applicable federal, state or local taxing authorities. Ad valorem taxes are generally based on reserve values at the end of each year.

Depreciation, depletion and amortization. This includes the expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs and oil. As a successful efforts company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and apportion these costs to each unit of production through depreciation, depletion and amortization expense.

Exploration. These are geological and geophysical costs, seismic costs, delay rentals and the costs of unsuccessful exploratory dry holes. This category also includes unproved property impairment and expenses associated with lease expirations.

General and administrative. These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees and legal compliance. Included in this category are any overhead expense reimbursements we receive from working interest owners of properties, for which we serve as the operator. These reimbursements are received during both the drilling and operational stages of a property's life.

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Impairment of oil and gas properties. Properties are evaluated for impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. When the carrying value exceeds the sum of the future undiscounted cash flows, an impairment loss is recognized for the difference between the fair market value and carrying value of the asset.

Accretion expense. This expense includes the monthly accretion of the future abandonment costs of tangible assets such as wells, service assets, pipelines and other facilities.

Gain (loss) on derivative instruments. We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of gas. None of our derivative contracts are designated as hedges for accounting purposes. Consequently, our derivative contracts are marked-to-market each quarter with changes in fair value recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on derivative instruments is dependent upon future gas prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty. In addition to gains and losses recognized from changes in fair value of the derivative instruments, gain (loss) on derivative instruments includes actual amounts realized from settlement of derivative instruments upon expiration.

Interest expense. We have historically financed a portion of our cash requirements with proceeds from fixed-rate Senior Unsecured Notes and our Revolving Credit Facility. As a result, we incur interest expense that is affected by our financing decisions. We capitalize interest on expenditures for significant exploration and development projects while activities are in progress to bring the assets to their intended use. Upon completion of construction of the asset, the associated capitalized interest costs are included within our asset base and depleted accordingly.

How We Evaluate Our Operations

In evaluating our current and future financial results, we focus on production and revenue growth, lease operating expense, general and administrative expense (both before and after non-cash stock compensation expense) and operating margin per unit of production. In addition to these metrics, we use Adjusted EBITDAX, a non-GAAP measure, to evaluate our financial results. We define Adjusted EBITDAX as net income (loss) before interest expense or interest income; income taxes; write-down of abandoned leases; impairments; depreciation, depletion and amortization (DD&A); amortization of deferred financing costs; gain (loss) on derivative instruments, net cash receipts (payments on settled derivative instruments, and premiums (paid) received on options that settled during the period, non-cash compensation expense; gain or loss from sale of interest in gas properties; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX is not a measure of net income as determined by generally accepted accounting principles in United States, or U.S. GAAP.

In addition to the operating metrics above, as we grow our reserve base, we will assess our capital spending by calculating our operated proved developed reserves and our operated proved developed finding costs and development costs. We believe that operated proved developed finding and development costs are one of the key measurements of the performance of an oil and gas exploration and production company. We will focus on our operated properties as we control the location, spending and operations associated with drilling these properties. In determining our proved developed finding and development costs, only cash costs incurred in connection with exploration and development will be used in the calculation, while the costs of acquisitions will be excluded because our board approves each material acquisition. In evaluating our proved developed reserve additions, any reserve revisions for changes in

commodity prices between years will be excluded from the assessment, but any performance related reserve revisions are included.

We also continually evaluate our rates of return on invested capital in our wells. We believe the quality of our assets combined with our technical and managerial expertise can generate attractive rates of return as we develop our acreage in the Utica Core Area and Our Marcellus Project Area. We review changes in drilling and completion costs; lease operating costs; natural gas, NGLs and oil prices; well productivity; and other factors in order to focus our drilling on the highest rate of return areas within our acreage.

Table of Contents**Overview of the Year Ended December 31, 2014 Results**

Operationally, our performance during the year ended December 31, 2014 reflects continued development of our acreage. During the year ended December 31, 2014, we achieved the following financial and operating results:

increased our average daily net production for the year ended December 31, 2014 by 1509% over the prior year, to 72.7 MMcf per day;

increased total net proved reserves by 353% to 355.8 Bcfe;

commenced drilling 57 gross (41.3 net) operated Utica Shale wells, completed 30 gross (27.3 net) operated Utica Shale wells and turned-to-sales 28 gross (21.8 net) wells during the year;

participated in 70 gross (13.5 net) non-operated Utica Shale wells, completed 60 gross (10.0 net) non-operated Utica Shale wells and turned-to-sales 65 gross (9.6 net) wells during the year;

net loss was \$183.2 million for the year ended December 31, 2014 compared to \$43.5 million for the year ended December 31, 2013; and

Adjusted EBITDAX was \$62.4 million for the year ended December 31, 2014 compared to \$(11.0) million for the year ended December 31, 2013. Adjusted EBITDAX is a non-GAAP financial measure. See *Non-GAAP Financial Measures* in Item 6. Selected Financial Data for more information.

Market Conditions

Prices for various quantities of natural gas, NGLs and oil that we produce significantly impact our revenues and cash flows. Prices for commodities, such as hydrocarbons, are inherently volatile. The following table lists average, high and low NYMEX Henry Hub prices for natural gas and NYMEX WTI prices for oil for the years ended December 31, 2014, 2013 and 2012.

	2014	2013	2012
NYMEX Henry Hub High (\$/MMBtu)	\$ 6.15	\$ 4.46	\$ 3.90
NYMEX Henry Hub Low (\$/MMBtu)	2.89	3.11	1.91
Average NYMEX Henry Hub (\$/MMBtu)	4.26	3.73	2.83
NYMEX WTI High (\$/Bbl)	\$ 107.26	\$ 110.53	\$ 109.77
NYMEX WTI Low (\$/Bbl)	53.27	86.68	77.69
Average NYMEX WTI (\$/Bbl)	92.91	98.05	94.15

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations

The following table illustrates the revenue attributable to natural gas, NGLs and oil sales for the years ended December 31, 2014 and 2013.

	Year Ended December 31,		
	2014	2013	Change
Revenues (in thousands):			
Natural gas sales	\$ 69,450	\$ 4,303	\$ 65,147
NGLs sales	21,048	63	20,985
Oil sales	47,318	8,569	38,749
Total revenues	\$ 137,816	\$ 12,935	\$ 124,881

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Our production grew by approximately 24,895 MMcfe for the year ended December 31, 2014 over the same period in 2013, which was attributable to additions from acquisitions and drilling success as we placed new wells on production, partially offset by natural decline. Our production for the years ended December 31, 2014 and 2013 is set forth in the following table:

	Year Ended December 31,		Change
	2014	2013	
Production:			
Natural gas (MMcf)	19,760.2	1,118.8	18,641.4
NGLs (Mbbbls)	536.0	1.3	534.7
Oil (Mbbbls)	594.9	87.2	507.7
Total (MMcfe)	26,545.5	1,650.2	24,895.3
Average daily production volume:			
Natural gas (Mcf/d)	54,137	3,065	51,072
NGLs (Bbls/d)	1,468	4	1,464
Oil (Bbls/d)	1,630	239	1,391
Total (Mcf/d)	72,727	4,521	68,206

Our average realized price received during the year ended December 31, 2014 was \$5.19 per Mcfe compared to \$7.84 per Mcfe in the year ended December 31, 2013. The decrease in the average realized price was due to a significantly higher percentage of our total revenues being driven by natural gas production in the year ended December 31, 2014, as compared to the year ended December 31, 2013, and to the overall decline in oil and natural gas commodity prices during the year ended December 31, 2014. Average realized prices (wellhead) do not include any third party transportation costs, which are reported in transportation, gathering and compression expense on our statements of operations. Average realized price calculations for the years ended December 31, 2014 and 2013 are shown in the following table.

	Year Ended December 31,		Change
	2014	2013	
Volume weighted average realized prices:			
Natural gas (\$/Mcf)(1)	\$ 3.51	\$ 3.85	\$ (0.34)
NGLs (\$/Bbl)	39.27	48.17	(8.90)
Oil (\$/Bbl)	79.54	98.22	(18.68)
Average price (\$/Mcf)	5.19	7.84	(2.65)
Differential to Average NYMEX Henry Hub(2)	(0.75)	0.06	(0.69)
Differential to Average NYMEX WTI(2)	(13.37)	(0.38)	(12.99)

- (1) Including the effects of commodity hedging, the average effective natural gas sales price for the year ended December 31, 2014 would have been \$4.57 per Mcf. The total volume of gas associated with these hedges for the year ended December 31, 2014 represented approximately 38% of our total natural gas sales volumes for the year ended December 31, 2014. There were no commodity derivatives in place for the year ended December 31, 2013.
- (2) Differential compares actual NYMEX Henry Hub and WTI prices to our actual volume-weighted average realized prices for natural gas and oil, respectively.

Table of Contents**Costs and Expenses**

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per Mcfe, basis. The following table presents information about certain of our expenses for the years ended December 31, 2014 and 2013.

	Year Ended December 31,		
	2014	2013	Change
Operating expenses (in thousands):			
Lease operating	\$ 8,518	\$ 2,576	\$ 5,942
Transportation, gathering and compression	18,114	67	18,047
Production and ad valorem taxes	7,084	77	7,007
Depreciation, depletion and amortization	89,218	6,163	83,055
General and administrative	45,392	21,276	24,116
Operating expenses per Mcfe:			
Lease operating	\$ 0.32	\$ 1.56	\$ (1.24)
Transportation, gathering and compression	0.68	0.04	0.64
Production, severance and ad valorem taxes	0.27	0.05	0.22
Depletion, depreciation and amortization	3.36	3.73	(0.37)
General and administrative	1.71	12.89	(11.18)

Lease operating expense was \$8.5 million in the year ended December 31, 2014 compared to \$2.6 million in the year ended December 31, 2013. The increase of \$5.9 million is attributable to higher production during the year ended December 31, 2014, as compared to the year ended December 31, 2013. Lease operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties. We incurred \$1.0 million of workover costs in the year ended December 31, 2014 compared to \$0 in the year ended December 31, 2013.

Transportation, gathering and compression expense was \$18.1 million during the year ended December 31, 2014 compared to less than \$0.1 million in the year ended December 31, 2013. These third party costs were higher in the year ended December 31, 2014 due to our production growth where we have third party gathering and compression agreements. We have excluded these costs in the calculation of average realized sales prices.

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were \$7.1 million in the year ended December 31, 2014 compared to less than \$0.1 million in the year ended December 31, 2013. Production and ad valorem taxes increased from the year ended December 31, 2013 to the year ended December 31, 2014 due to an increase in production volumes subject to production or ad valorem taxes.

Depletion, depreciation and amortization was approximately \$89.2 million in the year ended December 31, 2014 compared to \$6.2 million in the year ended December 31, 2013. The increase in the year ended December 31, 2014 when compared to the year ended December 31, 2013 is due to the increase in production during 2014. On a per Mcfe basis, DD&A decreased to \$3.36 in the year ended December 31, 2014 from \$3.73 in the year ended December 31, 2013, which was predominantly driven by a lower depletion rate. The decrease in depletion rate during the year ended December 31, 2014 was due to total proved reserves (the denominator) increasing at a higher rate than production (the numerator) over the year.

General and administrative expense was \$45.4 million for the year ended December 31, 2014 compared to \$21.3 million for the year ended December 31, 2013. The increase of \$24.1 million during the year ended December 31,

2014 when compared to year ended December 31, 2013 is primarily due to higher salaries and

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benefits related to the hiring of a significant number of new employees during the year ended December 31, 2014. Our personnel costs may continue to increase as we invest in our technical teams and other staffing to support our drilling program. We also incurred \$3.3 million related to the termination of drilling rig contracts for the year ended December 31, 2014. No such costs were incurred during the year ended December 31, 2013.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include exploration expense, impairment charges and accretion of asset retirement obligation expense and gain on reduction of pension obligations. The following table details our other operating expenses for the years ended December 31, 2014 and 2013.

	2014	2013	Change
Other Operating Expenses (in thousands):			
Exploration	\$ 21,186	\$ 3,022	\$ 18,164
Accretion of asset retirement obligations	791	364	427
Impairment of proved oil and natural gas properties	34,855	2,081	32,774
Gain on sale of assets	(960)		(960)
Gain on reduction of pension obligations	(2,208)		(2,208)

Exploration expense increased to \$21.2 million in the year ended December 31, 2014 compared to \$3.0 million in the year ended December 31, 2013. The increase was due to higher impairment of unproved properties related to lease expirations, dry hole costs, and delay rentals due to acreage increases and lease modifications. The following table details our exploration-related expenses for the years ended December 31, 2014 and 2013.

	2014	2013	Change
Exploration Expenses (in thousands):			
Geological and geophysical	\$ 802	\$ 124	\$ 678
Delay rentals	13,951	2,688	11,263
Impairment of unproved properties	5,671		5,671
Dry hole	762	210	552
	\$ 21,186	\$ 3,022	\$ 18,164

Impairment of unproved properties was \$5.7 million for the year ended December 31, 2014 compared to \$0 million for the year ended December 31, 2013. We assess individually significant unproved properties for impairment and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors, including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

Accretion of asset retirement obligations was \$0.8 million in the year ended December 31, 2014, compared to \$0.4 million in the year ended December 31, 2013. The increase in accretion expense primarily relates to the increase in the asset retirement obligations associated with new wells drilled during the year ended December 31, 2014 and existing wells acquired in the Oxford Acquisition in June 2013.

Impairment of proved oil and natural gas properties was \$34.9 million for the year ended December 31, 2014 compared to \$2.1 million for the year ended December 31, 2013. An analysis of proved properties determined the future undiscounted cash flows were less than the carrying value for certain asset groupings. An

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impairment expense was recognized for these asset groupings based on the difference between the fair market value and carrying value of the asset groupings. Approximately \$30.9 million of this impairment expense relates to our conventional properties acquired in the Oxford Acquisition in June 2013 and the remaining \$4.0 million relates to unconventional properties in our Utica Core Area.

Gain on sale of assets was \$1.0 million for the year ended December 31, 2014 representing the gain on the sale of a central processing facility. No such sales occurred during the year ended December 31, 2013.

Gain on reduction of pension obligations was \$2.2 million for the year ended December 31, 2014, compared to \$0 in the year ended December 31, 2013. Effective March 31, 2014, the Company froze the benefit accruals related to the defined benefit pension plan it assumed in the Oxford Acquisition, which was completed during the fiscal 2013.

Other Income (Expense)

Gain on derivative instruments was \$20.8 million for the year ended December 31, 2014. There was no gain or loss on derivatives in the year ended December 31, 2013 as the Company did not have derivative instruments in place during this period. The Company made cash payments of approximately \$1.6 million on derivative instruments that settled during the year ended December 31, 2014.

Interest expense, net was \$48.3 million for the year ended December 31, 2014 compared to \$20.9 million for year ended December 31, 2013. The increase in interest expense during the year ended December 31, 2014 was due to the June 2013 and December 2013 issuances of \$281.2 million and \$100.0 million, respectively, of our Senior Unsecured Notes, net of discounts and offering expenses, as well as the \$26.9 million drawn on our Revolving Credit Facility during 2014.

Income tax expense was \$71.8 million for the year ended December 31, 2014 primarily related to a charge of \$97.6 million to record the initial impact of the change in our tax status as a result of the Corporate Reorganization, partially offset by the income tax benefit of \$25.8 million realized from the operating loss following the Corporate Reorganization.

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012**Natural Gas, NGLs and Oil Sales, Production and Realized Price Calculations**

The following table illustrates the revenue attributable to natural gas, NGLs and oil sales for each of the years ended December 31, 2013 and 2012.

	Year Ended December 31,		
	2013	2012	Change
Revenues (in thousands):			
Natural gas sales	\$ 4,303	\$ 27	\$ 4,276
NGLs sales	63		63
Oil sales	8,569	343	8,226
Total revenues	\$ 12,935	\$ 370	\$ 12,565

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Our production grew by approximately 1,615 MMcfe for the year ended December 31, 2013 over the same period in 2012, which was attributable to additions from acquisitions and drilling success as we placed new wells on production, partially offset by natural decline. Our production for the years ended December 31, 2013 and 2012 is set forth in the following table:

	Year Ended December 31,		
	2013	2012	Change
Production:			
Natural gas (MMcf)	1,118.8	7.7	1,111.1
NGLs (Mbbls)	1.3		1.3
Oil (Mbbls)	87.2	4.5	82.7
Total (MMcfe)	1,650.2	34.6	1,615.6
Average daily production volume:			
Natural gas (Mcf/d)	3,065	21	3,044
NGLs (Bbls/d)	4		4
Oil (Bbls/d)	239	12	227
Total (Mcf/d)	4,521	95	4,426

Our average realized price received during fiscal 2013 was \$7.84 per Mcfe compared to \$10.69 per Mcfe in fiscal 2012. The decrease in the average realized price was due to a significantly higher percentage of our total revenues being driven by natural gas production in fiscal 2013, as compared to fiscal 2012. Average realized prices (wellhead) do not include any third party transportation costs, which are reported in transportation, gathering and compression expense on our statements of operations. Average realized price calculations for each of the years ended December 31, 2013 and 2012 are shown in the following table:

	Year Ended December 31,		
	2013	2012	Change
Volume weighted average realized prices:			
Natural gas (\$/Mcf)	\$ 3.85	\$ 3.53	\$ 0.32
NGLs (\$/Bbl)	48.17		48.17
Oil (\$/Bbl)	98.22	76.19	22.03
Average price (\$/Mcf)	7.84	10.69	(2.85)
Differential to Average NYMEX Henry Hub(1)	0.06	0.62	(0.56)
Differential to Average NYMEX WTI(1)	(0.38)	(17.51)	17.13

- (1) Differential compares actual NYMEX Henry Hub and WTI prices to our actual volume-weighted average realized prices for natural gas and oil, respectively.

Table of Contents**Costs and Expenses**

We believe some of our expense fluctuations are best analyzed on a unit-of-production, or per Mcfe, basis. The following table presents information about certain of our expenses for each of the years ended December 31, 2013 and 2012.

	Year Ended December 31,		
	2013	2012	Change
Operating expenses (in thousands):			
Lease operating	\$ 2,576	\$ 16	\$ 2,560
Transportation, gathering and compression	67		67
Production, severance and ad valorem taxes	77	1	76
Depletion, depreciation and amortization	6,163	404	5,759
General and administrative	21,276	4,425	16,851
Operating expenses per Mcfe:			
Lease operating	\$ 1.56	\$ 0.46	\$ 1.10
Transportation, gathering and compression	0.04		0.04
Production, severance and ad valorem taxes	0.05	0.03	0.02
Depletion, depreciation and amortization	3.73	11.68	(7.95)
General and administrative	12.89	127.89	(115.00)

Lease operating expense was \$2.6 million in fiscal 2013 compared to \$0.02 million in fiscal 2012. The increase of \$2.6 million is attributable to higher production during the year ended December 31, 2013, as compared to the year ended December 31, 2012. Lease operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties. We incurred \$0.03 million of workover costs in the year ended December 31, 2013 compared to \$0 in the year ended December, 31 2012.

Transportation, gathering and compression expense was \$0.07 million in the year ended December 31, 2013 compared to \$0 in the year ended December 31, 2012. These third party costs were higher in the year ended December 31, 2013 due to our production growth where we have third party gathering and compression agreements. We have excluded these costs in the calculation of average realized sales prices.

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were \$0.08 million in the year ended December 31, 2013 compared to less than \$0.01 million in the year ended December 31, 2012. Production and ad valorem taxes increased from the year ended December 31, 2012 to the year ended December 31, 2013 due to an increase in production volumes subject to production or ad valorem taxes.

Depletion, depreciation and amortization was approximately \$6.2 million in the year ended December 31, 2013 compared to \$0.4 million in the year ended December 31, 2012. The increase in the year ended December 31, 2013 when compared to the year ended December 31, 2012 is due to the increase in production during the year ended December 31, 2013. On a per Mcfe basis, DD&A decreased to \$3.73 in fiscal 2013 from \$11.68 in fiscal 2012, which was predominantly driven by a lower depletion rate. The decrease in depletion rate in the year ended December 31, 2013 was due to total proved reserves (the denominator) increasing at a higher rate than production (the numerator) over the year.

General and administrative expense was \$21.3 million for the year ended December 31, 2013 compared to \$4.4 million for the year ended December 31, 2012. The year ended December 31, 2013 increase of \$16.9 million when compared to the year ended December 31, 2012 is primarily due to higher salaries and benefits during the year ended December 31, 2013 related to the hiring of a significant number of new employees, including those that became employees through the Oxford Acquisition. In addition we recorded \$0.04 million and \$0.03 million of non-cash incentive unit compensation charges for the fiscal year end 2013 and 2012, respectively.

Table of Contents**Other Operating Expenses**

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include exploration expense, impairment charges, and accretion expense. The following table details our other operating expenses for each of the years ended December 31, 2013 and 2012.

	Year Ended December 31,		
	2013	2012	Change
Other Operating Expenses (in thousands):			
Exploration	\$ 3,022	\$ 4,692	\$ (1,670)
Accretion	364		364
Impairment of proved properties	2,081		2,081

Exploration expense decreased to \$3.0 million in fiscal 2013 compared to \$4.7 million in fiscal 2012 due to lower dry hole costs, impairment of unproved properties and seismic costs, partially offset by higher delay rentals due to acreage increases. The following table details our exploration-related expenses for each of the years ended December 31, 2013 and 2012.

	Year Ended December 31,		
	2013	2012	Change
Exploration Expenses (in thousands):			
Geological and geophysical	\$ 124	\$ 263	\$ (139)
Delay rentals	2,688	213	2,475
Impairment of unproved properties		793	(793)
Dry hole	210	3,423	(3,213)
	\$ 3,022	\$ 4,692	\$ (1,670)

Impairment of unproved properties was \$0 in fiscal 2013 compared to \$0.8 million in fiscal 2012. We assess individually significant unproved properties for impairment on a quarterly basis and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists' evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

Accretion expense was \$0.4 million in fiscal 2013, compared to \$0 in fiscal 2012. Accretion expense relates to the increase in the asset retirement obligations associated with new wells drilled during fiscal 2013 and existing wells acquired in the Oxford Acquisition in June 2013.

Impairment of proved oil and gas properties increased to \$2.1 million in fiscal 2013 compared to \$0 in fiscal 2012. Our analysis of these properties determined that undiscounted cash flows were less than their carrying value. We compared the carrying value to estimated fair value and recognized an impairment charge. These assets were

evaluated for impairment due to performance-related issues relative to our initial reserve expectations.

Other Income (Expense)

Interest expense, net was \$20.9 million for fiscal 2013. We incurred \$0 in interest expense in fiscal 2012. The increase in interest expense in fiscal 2013 was due to the June 2013 and December 2013 issuances of \$281.2 million and \$100.0 million, respectively, of our Senior Unsecured Notes, net of discounts, and \$0.02 million of related offering expenses. We used the net proceeds from the June 2013 issuance, along with contributions from

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our equity investors, to fund our acquisition of Oxford. In January 2014, we paid our semi-annual interest on our Senior Unsecured Notes with additional Senior Unsecured Notes at an interest rate of 13.0% as opposed to paying in cash at the cash interest rate of 12.0%. Interest expense is net of capitalized interest on expenditures made in connection with exploration and development projects that are not subject to current amortization.

At our option, the first two interest payments subsequent to the issuance of our Senior Unsecured Notes may be satisfied with PIK Interest. Also at our option, the subsequent four semi-annual interest payments thereafter may be paid in the form of 6.0% annum per cash and 7.0% annum in PIK Interest. Thereafter (subsequent to the sixth semi-annual interest payment), interest can only be paid in cash at 12.0% per annum.

Cash Flows, Capital Resources and Liquidity

Cash Flows

Cash flows from operations are primarily affected by production volumes and commodity prices. Our cash flows from operations also are impacted by changes in working capital. Short-term liquidity needs are satisfied by our operating cash flow, proceeds from asset sales, and proceeds from issuances of debt and equity. We sell a large portion of our production at the wellhead under floating market contracts.

Year Ended December 31, 2014 Compared to the Year Ended December 31, 2013

Net cash provided by operations in the year ended December 31, 2014 was \$23.3 million compared to \$15.3 million in the year ended December 31, 2013. The increase in cash provided from operating activities from the year ended 2013 to 2014 reflects an increase in production, partially offset by higher operating costs. Net cash provided from operations is also affected by working capital changes or the timing of cash receipts and disbursements.

Net cash used in investing activities in the year ended December 31, 2014 was \$733.2 million compared to \$897.1 million in the year ended December 31, 2013.

During the year ended December 31, 2014, we:

spent \$745.8 million on capital expenditures for oil and natural gas properties;

spent \$3.6 million on property and equipment;

received proceeds of \$15.5 million from the sale of a central processing facility; and

received proceeds of \$0.8 million related to the acquisition of Eclipse Operating.

During the year ended December 31, 2013, we:

spent \$252.8 million on capital expenditures for oil and natural gas properties;

spent \$651.8 million on the Oxford acquisition; and

received proceeds of \$8.5 million from the sale of properties.

Net cash provided by financing activities in the year ended December 31, 2014 decreased to \$667.9 million compared to \$964.3 million in the year ended December 31, 2013.

During the year ended December 31, 2014, we:

issued shares of common stock in our IPO for proceeds to us totaling approximately \$544.7 million, net of \$5.3 million of IPO costs;

received capital contributions of \$124.7 million from private equity funds managed by EnCap and investment funds controlled by certain members of our management prior to the IPO.

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During the year ended December 31, 2013, we:

received proceeds of \$380.7 million from the issuance of debt, net of debt issuance costs; and

received capital contributions of \$583.6 million from private equity funds managed by EnCap and investment funds controlled by certain members of our management.

Year Ended December 31, 2013 Compared to the Year Ended December 31, 2012

Net cash provided by (used in) operations in fiscal 2013 was \$15.2 million compared to \$(3.4) million in fiscal 2012. The increase in cash provided from operating activities from fiscal 2012 to fiscal 2013 reflects an increase in production, partially offset by higher operating costs. Net cash provided from operations is also affected by working capital changes or the timing of cash receipts and disbursements.

Net cash used in investing activities in fiscal 2013 was \$897.1 million compared to \$47.5 million in fiscal 2012.

During the year ended December 31, 2013, we:

spent \$252.8 million on capital expenditures for oil and natural gas properties;

spent \$651.8 million, net of cash acquired, on the Oxford Acquisition; and

received proceeds of \$8.5 million from the sale of properties.

During the year ended December 31, 2012, we:

spent \$158.1 million on acreage, primarily in the Utica Shale, and capital expenditures of \$21.1 million; and

received proceeds of \$126.5 million primarily related to the sale of approximately 21,000 net acres within our area of mutual interest with Antero Resources, along with other insignificant sales.

Net cash provided by financing activities in fiscal 2013 increased to \$964.3 million in fiscal 2013 compared to \$68.9 million in fiscal 2012.

During the year ended December 31, 2013, we:

received proceeds of \$380.7 million from the issuance of debt, net of debt issuance costs; and

received capital contributions of \$583.6 million from private equity funds managed by EnCap and investment funds controlled by certain members of our management.

During 2012, we received capital contributions of \$69.6 million from private equity funds managed by EnCap and investment funds controlled by certain members of management.

Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, asset sales and access to the debt and equity capital markets. We must find new and develop existing reserves to maintain and grow our production and cash flows. We accomplish this primarily through successful drilling programs which requires substantial capital expenditures. We periodically review capital expenditures and adjust our budget based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We will continue using net cash on hand, cash flows from operations and proceeds available under our Revolving Credit Facility to satisfy near-term financial obligations and liquidity needs, and as necessary, we will seek additional sources of debt or equity to fund these

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requirements. Longer-term cash flows are subject to a number of variables including the level of production and prices we receive for our production as well as various economic conditions that have historically affected the natural gas and oil business. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves

Credit Arrangements

Long-term debt at December 31, 2014, excluding discount, totaled \$422.5 million and at December 31, 2013 totaled \$400.0 million, consisting of our Senior Unsecured Notes.

In February 2014, we entered into our \$500.0 million Revolving Credit Facility which was amended and restated on January 12, 2015, and which matures on January 15, 2018 and includes customary affirmative and negative covenants. As of December 31, 2014, the borrowing base was \$100 million and the Company had no outstanding borrowings. After considering outstanding letters of credit issued by the Company, totaling \$26.9 million, the Company had available capacity on our Revolving Credit Facility of \$73.1 million at December 31, 2014. In March 2015, we had a redetermination of the borrowing base under the Revolving Credit Facility, which increased the borrowing base to \$125 million. The borrowing base under our Revolving Credit Facility is scheduled to be redetermined semi-annually (in April and October) beginning on April 1, 2015.

We have the right to redeem all or a portion of the Senior Unsecured Notes prior to December 20, 2015 by paying a redemption price equal to a make whole premium equal to the greater of 106.0% or an amount computed under the indenture governing the Senior Unsecured Notes plus accrued and unpaid interest. After December 20, 2015, we may redeem all or a part of the Senior Unsecured Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest:

Year following December 20, 2015	Redemption Price
Year 1	106.0%
Year 2	103.0%
Year 3 and thereafter	100.0%

The indenture governing our Senior Unsecured Notes imposes limitations on the payment of dividends and other restricted payments (as defined in the indenture). The indenture also contains customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at December 31, 2014.

At our option, for the first 2 semi-annual interest payments following the date the notes were first issued, interest was payable by increasing the principal amount of the Senior Unsecured Notes (PIK interest) or in cash. At our option, the subsequent four semi-annual interest payments thereafter may be payable in the form of 6.0% per annum in cash and 7.0% per annum in PIK interest or all in cash. Thereafter, interest can only be paid as cash interest.

Commodity Hedging Activities

Our primary market risk exposure is in the prices we receive for our natural gas, NGLs and oil production. Realized pricing is primarily driven by the spot regional market prices applicable to our U.S. natural gas, NGLs and oil production. Pricing for natural gas, NGLs and oil production has been volatile and unpredictable for several years, and

we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate the potential negative impact on our cash flow caused by changes in natural gas, NGLs and oil prices, we may enter into financial commodity derivative contracts to ensure that we receive minimum prices for a portion of our future natural gas production when management believes that favorable future prices can be secured. We typically hedge the NYMEX Henry Hub price for natural gas, the West Texas Intermediate, or WTI, price for oil and an NGLs basket based on prices at Mont Belvieu, Texas.

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Our hedging activities are intended to support natural gas, NGLs and oil prices at targeted levels and to manage our exposure to price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, zero cost collars that set a floor and ceiling price for the hedged production, and puts which require us to pay a premium either up front or at settlement and allow us to receive a fixed price at our option if the put price is above the market price. As of December 31, 2014, we had entered into the following derivative contracts:

Description(1)	Volume (MMBtu/d)	Production Period		Weighted Average Price (\$/MMBtu)	
Natural Gas Swaps:					
	66,219	January 2015	December 2015	\$	3.797
	25,000	January 2016	December 2016	\$	3.660
Natural Gas Three-way Collar:					
Floor purchase price (put)	15,000	January 2015	December 2015	\$	3.60
Ceiling sold price (call)	15,000	January 2015	December 2015	\$	3.80
Floor sold price (put)	15,000	January 2015	December 2015	\$	3.00
Natural Gas Put Sale:					
Put sold	16,800	January 2015	December 2015	\$	3.350
Natural Gas Collar:					
Purchased put	5,000	January 2015	March 2015	\$	4.000
Call sold	5,000	January 2015	March 2015	\$	4.750
Basis Swaps:					
	25,000	January 2015	March 2015	\$	(1.067)
	25,000	April 2015	October 2015	\$	(1.208)

(1) The natural gas derivative contracts are settled based on the NYMEX price of natural gas at Henry Hub on the last commodity business day of the futures contract corresponding to the calculation period.

By using derivative instruments to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have derivative instruments in place with Bank of Montreal and Key Bank NA. We believe both institutions currently are an acceptable credit risk. As of December 31, 2014, we did not have any past due receivables from counterparties.

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Subsequent to December 31, 2014, we entered into the following derivative instruments to mitigate our exposure to both oil and gas prices:

Natural Gas:

Description	(MMBtu/d)	Production Period		Weighted Average Price (\$/MMBtu)
Floor sold (put)	16,800	April 2015	October 2015	\$ 2.87
Floor purchased (put)	16,800	April 2015	October 2015	\$ 3.35
Floor sold (put)	16,800	January 2016	December 2016	\$ 2.75

Oil WTI:	(Bbls/d)	Production Period		Weighted Average Price (\$/Bbl)
Collar				
Floor purchased (put)	3,000	March 2015	February 2016	\$ 55.00
Ceiling sold (call)	3,000	March 2015	February 2016	\$ 61.40

Capital Requirements

Our primary needs for cash are for exploration, development and acquisition of natural gas and oil properties and repayment of principal and interest on outstanding debt. During the year ended December 31, 2014, costs incurred for drilling projects were \$809.4 million, and for fiscal 2013 were \$261.8 million. In the year ended December 31, 2014 there were no significant acquisitions of mineral properties, while during fiscal 2013, costs incurred for acquisition of unproved property totaled \$621.0 million, primarily in the Utica Shale. Our fiscal 2014 capital program, excluding acquisitions, was funded by net cash flow from operations, proceeds from asset sales and proceeds from the issuances of Senior Unsecured Notes and common stock.

Our capital expenditure budget for fiscal 2015 excludes acquisitions, other than leasehold acquisitions, and is currently set at \$640 million. We expect to fund our capital expenditures for 2015 with cash generated by operations, borrowings under our revolving credit facility, and net proceeds received from the private placement. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, natural gas, NGLs and oil prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. A reduction in natural gas, NGLs or oil prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. Our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets.

Capitalization

As of December 31, 2014 and December 31, 2013, our total debt, excluding debt discount and capitalization were as follows (in millions):

	2014	2013
Senior Unsecured Notes	\$ 422.5	\$ 400.0
Stockholders equity	1,152.7	667.9

Total capitalization	\$ 1,575.2	\$ 1,067.9
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Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, firm transportation, gas processing, gathering, and compressions services, asset retirement obligations. As of December 31, 2014 and December 31, 2013, we do not have any capital leases, any significant off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed any debt of any unrelated party. The table

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below provides estimates of the timing of future payments that we are obligated to make based on agreements in place at December 31, 2014. In addition to the contractual obligations listed in the table below, our balance sheet at December 31, 2014 reflects accrued interest payable on our Senior Unsecured Notes of \$25.2 million, compared to \$20.3 million as of December 31, 2013. We settled \$14.8 million of our accrued interest in January 2015 through the issuance of additional Senior Unsecured Notes.

The following summarizes our contractual financial obligations at December 31, 2014 and their future maturities. We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our Revolving Credit Facility, additional debt and equity issuances, and proceeds from asset sales (in millions):

	2015	2016	2017	2018	2019	Thereafter	Total
Senior unsecured notes ⁽¹⁾	\$	\$	\$	\$ 422.5	\$	\$	\$ 422.5
Drilling rig commitments ⁽²⁾	23.5	18.7	8.1				50.3
Firm transportation ⁽³⁾	19.7	42.0	120.2	130.0	123.5	1,123.1	1,558.5
Gas processing, gathering, and compression services ⁽⁴⁾	7.5	7.4	8.0				22.9
Asset retirement obligation liability ⁽⁵⁾						17.4	17.4
Operating leases	0.8	0.7	0.8	0.8	0.8	3.4	7.3
Vehicle loans	0.3	0.3	0.3	0.3	0.1		1.3
	\$ 51.8	\$ 69.1	\$ 137.4	\$ 553.6	\$ 124.4	\$ 1,143.9	\$ 2,080.2

- (1) The ultimate settlement amount and timing cannot be precisely determined in advance. See Note 8 to our consolidated financial statements as of and for the year ended December 31, 2014.
- (2) At December 31, 2014, we had contracts for the services of three rigs, which expire at various dates from February 2015 through September 2017. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (3) We have entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit us to transport minimum daily natural gas or NGL volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (4) Contractual commitments for gas processing, gathering and compression service agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.
- (5) Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

Other

We lease acreage that is generally subject to lease expiration if operations are not commenced within a specified period, generally 5 years and approximately 52% of our leases in the Utica Core Area have a 5-year extension at our option. We do not expect to lose significant lease acreage because of failure to commence operations due to inadequate capital, equipment or personnel. However, based on our evaluation of prospective economics, including the cost of infrastructure to connect production, we have allowed acreage to expire and will allow additional acreage to expire in the future. To date, our expenditures to comply with environmental or safety

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regulations have not been a significant component of our cost structure and are not expected to be significant in the future. However, new regulations, enforcement policies, claims for damages or other events could result in significant future costs.

Interest Rates

At December 31, 2014, we had \$422.5 million as compared to \$400.0 million as of December 31, 2013 of Senior Unsecured Notes outstanding, excluding discounts, that bear interest at a fixed cash interest rate of 12.0% and is due semi-annually from the date of issuance. At our option, the first two interest payments can be PIK Interest at a 13% per annum interest rate. Also at our option, the subsequent four semi-annual interest payments thereafter may be paid in the form of 6.0% per annum in cash and 7.0% per annum in PIK Interest. Thereafter (subsequent to the sixth semi-annual interest payment), interest can only be paid in cash at a 12.0% per annum interest rate.

In February 2014, the Company entered into a \$500 million senior secured revolving bank credit facility which was amended and restated on January 12, 2015 and matures in 2018. Borrowings under our Revolving Credit Facility are subject to borrowing base limitations based on the collateral value of the Company's proved properties and commodity hedge positions and are subject to quarterly redeterminations through April 1, 2015 and semiannual redeterminations thereafter. At December 31, 2014, the borrowing base was \$100 million and the Company had no outstanding borrowings. In March 2015, we had a redetermination of the borrowing base, which increased the borrowing base to \$125 million. After considering outstanding letters of credit issued by the Company, totaling \$26.9 million, the Company had available capacity on our Revolving Credit Facility of \$73.1 million at December 31, 2014.

Off-Balance Sheet Arrangements

We do not currently utilize any off-balance sheet arrangements with unconsolidated entities to enhance our liquidity or capital resource position, or for any other purpose. However, as is customary in the oil and gas industry, we have various contractual work commitments which are described above under Cash Contractual Obligations.

Inflation and Changes in Prices

Our revenues, the value of our assets and our ability to obtain bank loans or additional capital on attractive terms have been and will continue to be affected by changes in natural gas, NGLs and oil prices and the costs to produce our reserves. Natural gas, NGLs and oil prices are subject to significant fluctuations that are beyond our ability to control or predict. Although certain of our costs and expenses are affected by general inflation, it does not normally have a significant effect on our business. We expect costs in fiscal 2015 to continue to be a function of supply and demand.

Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon 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 and liabilities, the disclosure of contingent assets and liabilities at year end, the reported amounts of revenues and expenses during the year and proved natural gas and oil reserves. Some accounting policies involve judgments and uncertainties to such an extent there is a 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 we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Actual results could differ from the estimates and

assumptions used.

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Certain accounting estimates are considered to be critical if (a) the nature of the estimates and assumptions is material due to the level of subjectivity and judgment necessary to account for highly uncertain matters or the susceptibility of such matters to changes; and (b) the impact of the estimates and assumptions on financial condition or operating performance is material.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at December 31, 2014. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by \$8.4 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by \$8.8 million.

Natural Gas and Oil Properties

We follow the successful efforts method of accounting for natural gas and oil producing activities. Unsuccessful exploration drilling costs are expensed and can have a significant effect on reported operating results. Successful exploration drilling costs and all development costs are capitalized and systematically charged to expense using the units of production method based on proved developed natural gas and oil reserves as estimated by our engineers and audited by independent engineers. Costs incurred for exploratory wells that find reserves that cannot yet be classified as proved are capitalized on our balance sheet if (a) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and (b) we are making sufficient progress assessing the reserves and the economic and operating viability of the project. Proven property leasehold costs are amortized to expense using the units of production method based on total proved reserves. Properties are assessed for impairment as circumstances warrant (at least annually) and impairments to value are charged to expense. The successful efforts method inherently relies upon the estimation of proved reserves, which includes proved developed and proved undeveloped volumes.

Proved reserves are defined by the SEC as those volumes of natural gas, NGLs, condensate and crude oil that geological and engineering data demonstrate with reasonable certainty are economically recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are volumes expected to be recovered through existing wells with existing equipment and operating methods, or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Although our engineers are knowledgeable of and follow the guidelines for reserves established by the SEC, including the rule revisions designed to modernize the oil and gas company reserves reporting requirements which were adopted effective December 31, 2009, the estimation of reserves requires engineers to make a significant number of assumptions based on professional judgment. Reserve estimates are updated at least annually and consider recent production levels and other technical information. Estimated reserves are often subject to future revisions, which could be substantial, based on the availability of additional information, including: reservoir performance, new geological and geophysical data, additional drilling, technological advancements, price and cost changes and other economic factors. Changes in natural gas, NGLs and oil prices can lead to a decision to start-up or shut-in production, which can lead to revisions to reserve quantities. Reserve revisions in turn cause adjustments in our depletion rates. We cannot predict what reserve revisions may be required in future periods. Reserve estimates are reviewed and approved by our Vice President, Business Development, Finance and Reservoir Engineering who reports directly to our Chief Financial Officer. To further ensure the reliability of our reserve estimates, we engage independent petroleum engineers to prepare our estimates of proved reserves at least annually. NSAI, our independent petroleum engineers, prepared 100% of our reserves in 2014, 2013 and 2012. For additional discussion, see Item 1. Business Proved Reserves.

Depletion rates are determined based on reserve quantity estimates and the capitalized costs of producing properties. As the estimated reserves are adjusted, the depletion expense for a property will change, assuming no change in production volumes or the capitalized costs. While total depletion expense for the life of a property is limited to the property's total cost, proved reserve revisions result in a change in the timing of when depletion expense is recognized.

Downward revisions of proved reserves may result in an acceleration of depletion expense, while upward revisions tend to lower the rate of depletion expense recognition. Estimated reserves are used as the basis for calculating the expected future cash flows from property asset groups, which are used to

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determine whether that property may be impaired. Reserves are also used to estimate the supplemental disclosure of the standardized measure of discounted future net cash flows relating to natural gas and oil producing activities and reserve quantities in Note 17 to our consolidated financial statements. Changes in the estimated reserves are considered a change in estimate for accounting purposes and are reflected on a prospective basis.

We monitor our long-lived assets recorded in natural gas and oil properties in our consolidated balance sheets to ensure they are fairly presented. We must evaluate our properties for potential impairment when circumstances indicate that the carrying value of an asset could exceed its fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Such events include a projection of future natural gas, NGLs and oil prices, an estimate of the ultimate amount of recoverable natural gas, NGLs and oil reserves that will be produced from the property asset groups future production, future production costs, future abandonment costs, and future inflation. The need to test a property asset group for impairment can be based on several factors, including a significant reduction in sales prices for natural gas, NGLs and/or oil, unfavorable adjustments to reserves, physical damage to production equipment and facilities, a change in costs, or other changes to contracts or environmental regulations. Our natural gas and oil properties are reviewed for potential impairments at the lowest levels for which there are identifiable cash flows that are largely independent of other groups of assets. All of these factors must be considered when testing a property asset groups carrying value for impairment.

The review is done by determining if the historical cost of proved properties less the applicable accumulated depreciation, depletion and amortization is less than the estimated undiscounted future net cash flows. The expected undiscounted future net cash flows are estimated based on our plans to produce and develop reserves. Expected undiscounted future net cash inflows from the sale of produced reserves are calculated based on estimated future prices and estimated operating and development costs. We estimate prices based upon market related information including published futures prices. The estimated future level of production, which is based on proved and risk adjusted probable reserves, has assumptions surrounding the future levels of prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. In certain circumstances, we also consider potential sales of properties to third parties in our estimates of undiscounted future cash flows. When the carrying value exceeds the sum of undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future net cash flows using a discount rate similar to that used by market participants) and the carrying value of the asset. We cannot predict whether impairment charges may be required in the future.

We believe that a sensitivity analysis regarding the effect of changes in assumptions on estimated impairment is impractical to provide because of the number of assumptions and variables involved which have interdependent effects on the potential outcome. If natural gas, NGLs and oil prices decrease or drilling efforts are unsuccessful, we may be required to record additional impairments.

We evaluate our unproved property investment periodically for impairment. The majority of these costs generally relate to the acquisition of leaseholds. The costs are capitalized and evaluated (at least quarterly) as to recoverability, based on changes brought about by economic factors and potential shifts in business strategy employed by management. Impairment of a significant portion of our unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. Potential impairment of individually significant unproved property is assessed on a property-by-property basis considering a combination of time, geologic and engineering factors.

Acquisitions

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is

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subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

Asset Retirement Obligations

We have significant obligations to remove tangible equipment and restore land at the end of natural gas and oil production operations. Removal and restoration obligations are primarily associated with plugging and abandoning wells. Estimating the future asset removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations.

Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate retirement costs, inflation factors, credit-adjusted discount rates, timing of retirement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement obligation (ARO), a corresponding adjustment is made to the natural gas and oil property balance. For example, as we analyze actual plugging and abandonment in formation, we may revise our estimate of current costs, the assumed annual inflation of the costs and/or the assumed productive lives of our wells. In addition, increases in the discounted ARO liability resulting from the passage of time are reflected as accretion expense, a component of depletion, depreciation and amortization in the accompanying consolidated statements of operations. Because of the subjectivity of assumptions and the relatively long lives of most of our wells, the costs to ultimately retire our wells may vary significantly from prior estimates.

Revenue Recognition

Natural gas, NGLs and oil sales are recognized when the products are sold and delivery to the purchaser has occurred. We use the sales method to account for gas imbalances, recognizing revenue based on gas delivered rather than our working interest share of gas produced. We generally sell natural gas, NGLs and oil under two types of agreements, which are common in our industry. Both types of agreements include transportation charges. We report our gathering and transportation costs in accordance with Financial Accounting Standards Board (FASB) Section 605-45-05 of Subtopic 605-45 for Revenue Recognition.

Under one type of agreement, we sell natural gas, NGLs or oil at a specific delivery point, pay transportation, gathering and compression to a third party and receive proceeds from the purchaser with no deduction. In that case, we record these costs as transportation, gatherings and compression expense. The other type of agreement, which is only used on a portion of our historically acquired vertical wells, is a netback arrangement under which we sell natural gas and oil at the wellhead and collect a price, net of transportation incurred by the purchaser. In this case, we record revenue at the price we received from the purchaser. In the case of NGLs, we receive a net price from the purchaser (which is net of processing costs) which is recorded in revenue at the net price. Regardless of agreement type, revenue is recorded in the month the product is delivered to the purchaser as title has transferred.

To the extent we have not been paid for production related to a given reporting period, we record an accrual for revenue based on our estimate of the amount of production delivered to purchasers and the price we will receive, along with any related transportation costs. We estimate volumes delivered based on production information or from historical operating results of individual properties when production information is not available, for example, for certain non-operated properties. Prices for such production and related transportation costs are defined in sales

contracts and are readily determinable based on publicly available indices. Given the information available to us, we do not believe there to be any material implications with respect to uncertainties

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in developing these estimates and historically, our actual receipts have not been materially different from our accruals. The purchasers of such production have historically made payment for oil, NGLs and natural gas purchases within 30-60 days of the end of each production month, at which time any variance between our estimated revenue and transportation costs and actual payments is recorded.

Recent Accounting Pronouncements

Information related to recent accounting pronouncements is described in Note 3 to our consolidated financial statements and is incorporated herein by reference.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward-looking information provides indicators of how we view and manage our ongoing market-risk exposure. All of our market-risk sensitive instruments were entered into for purposes other than trading. All accounts are US dollar denominated.

Commodity Price Risk

We are exposed to market risks related to the volatility of natural gas, NGLs and oil prices. Realized prices are primarily driven by worldwide prices for oil and spot market prices for North American gas production. Natural gas and oil prices have been volatile and unpredictable for many years. Natural gas prices affect us more than oil prices because approximately 72% of our December 31, 2014 and 67% of our December 31, 2013 proved reserves were natural gas.

For a discussion of how we use financial commodity derivative contracts to mitigate some of the potential negative impact on our cash flow caused by changes in natural gas prices, see "Commodity Hedging Activities."

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at December 31, 2014. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by \$8.4 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by \$8.8 million.

Interest Rate Risk

At December 31, 2014, the cash interest rate with respect to our \$422.5 million of Senior Unsecured Notes is fixed at 12.0%, and is due semi-annually from the date of issuance.

We will be exposed to interest rate risk in the future if we draw on our Revolving Credit Facility. Interest on outstanding borrowings under our Revolving Credit Facility will accrue based on, at our option, LIBOR or the alternate base rate, in each case, plus an applicable margin that is determined based on our utilization of commitments under our Revolving Credit Facility. As of December 31, 2014, the borrowing base was \$100 million and the Company had no outstanding borrowings. After considering outstanding letters of credit issued by the Company, totaling \$26.9 million, the Company had available capacity on the Revolving Credit Facility of \$73.1 million at December 31, 2014.

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Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts (\$1.6 million at December 31, 2014), the sale of our oil and gas production (\$24.1 million at December 31, 2014) which we market to energy companies, end users and refineries, and joint interest receivables (\$20.7 million at December 31, 2014).

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with two counterparties, both of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately \$19.0 at December 31, 2014 includes the following values by bank counterparty: Bank of Montreal \$14.9 million; KeyBank NA \$4.1 million. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2014 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2014, we did not have past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require 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 partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth beginning on page F-1 of this report and are incorporated herein by reference.

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

Not applicable

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Item 9A. Controls and Procedures
Evaluation of Disclosure Controls and Procedures

The Company's management carried out an evaluation (as required by Rule 13a-15(b) of the Exchange Act), with the participation of the Company's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) of the Exchange Act), as of the end of the period covered by this Annual Report on Form 10-K. Based upon this evaluation, the Company's President and Chief Executive Officer and Executive Vice President and Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of the end of the period covered by this Annual Report on Form 10-K, such that the information relating to the Company and its consolidated subsidiaries required to be disclosed by the Company in the reports that it files or submits under the Exchange Act (i) is recorded, processed, summarized, and reported, within the time periods specified in the SEC's rules and forms, and (ii) is accumulated and communicated to the Company's management, including its principal executive and financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Controls

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15(d)-15(f) under the Exchange Act) during the fourth quarter of 2014 that has materially affected, or is reasonable likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

This annual report does not include a report of management's assessment regarding internal control over financial reporting or an attestation report of the company's registered public accounting firm due to a transition period established by rules of the Securities and Exchange Commission for newly public companies.

Item 9B. Other Information

Not applicable

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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 definite proxy statement for our 2015 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 definite proxy statement for our 2015 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Pursuant to General Instruction G(3) to Form 10-K, we incorporate by reference into this Item the information to be disclosed in our definite proxy statement for our 2015 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 definite proxy statement for our 2015 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 definite proxy statement for our 2015 Annual Meeting of Stockholders.

Item 15. Exhibits and Financial Statement Schedules

(1) Financial Statements:

The consolidated financial statements are listed on the Index to Financial Statements to this report beginning on page F-1 and incorporated herein by reference.

(2) Financial Statement Schedules:

No financial statement schedules are submitted because of the absence of the conditions under which they are required, the required information is insignificant or because the required information is included in the consolidated financial statements.

(3) Exhibits:

The following exhibits are filed as part of this Annual Report on Form 10-K.

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Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Eclipse Resources Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014)
3.2	Form of Amended and Restated Bylaws of Eclipse Resources Corporation (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014)
4.1	Stockholders Agreement, dated June 25, 2014, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P. and Eclipse Management, L.P. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 30, 2014)
4.2	Amended and Restated Registration Rights Agreement, dated January 28, 2015, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Eclipse Management, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II (Luxembourg) S.à.r.l., Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 29, 2015)
4.3	Form of Common Stock Certificate of Eclipse Resources Corporation (incorporated by reference to Exhibit 4.1 to Amendment No. 1 to the Company's Registration Statement on Form S-1 filed with the SEC on June 2, 2014)
10.1	Indenture, dated as of June 26, 2013, by and among Eclipse Resources I, LP and each of the subsidiary guarantors party thereto and Deutsche Bank Trust Company Americas relating to the 12.0% Senior Unsecured PIK Notes due 2018 (including form of Note) (incorporated by reference to Exhibit 10.1 to the Company's Registration Statement on Form S-1 filed with the SEC on May 5, 2014)
10.2	First Supplemental Indenture, dated as of June 26, 2013, by and among Eclipse Resources-Ohio, LLC, Eclipse Resources I, LP and Deutsche Bank Trust Company Americas, as trustee, relating to the 12.0% Senior Unsecured PIK Notes due 2018 (incorporated by reference to Exhibit 10.2 to the Company's Registration Statement on Form S-1 filed with the SEC on May 5, 2014)
10.3	Second Supplemental Indenture, dated as of November 1, 2013, by and among Buckeye Minerals & Royalties, LLC, Eclipse Resources I, LP and Deutsche Bank Trust Company Americas, as trustee, relating to the 12.0% Senior Unsecured PIK Notes due 2018 (incorporated by reference to Exhibit 10.3 to the Company's Registration Statement on Form S-1 filed with the SEC on May 5, 2014)
10.4	

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Third Supplemental Indenture, dated as of June 12, 2014, by and among Eclipse Resources Corporation, Eclipse Resources-Ohio, LLC, Eclipse Resources I, LP and Deutsche Bank Trust Company Americas, as trustee, relating to the 12.0% Senior Unsecured PIK Notes due 2018 (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1 filed with the SEC on February 11, 2015)

- 10.5 Fourth Supplemental Indenture, dated as of December 11, 2014, by and among Eclipse Resources Operating, LLC, Eclipse Resources I, LP and Deutsche Bank Trust Company Americas, as trustee, relating to the 12.0% Senior Unsecured PIK Notes due 2018 (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1 filed with the SEC on February 11, 2015)

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- 10.6 Fifth Supplemental Indenture, dated as of January 15, 2015, by and among Eclipse GP, LLC, Eclipse Resources Midstream, LP, Eclipse Resources Marketing, LP, Eclipse Resources I, LP and Deutsche Bank Trust Company Americas, as trustee, relating to the 12.0% Senior Unsecured PIK Notes due 2018 (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1 filed with the SEC on February 11, 2015)
- 10.7 Amended and Restated Credit Agreement, dated as of January 12, 2015, by and among Eclipse Resources I, LP, as borrower, Eclipse Resources Corporation, the Bank of Montreal, as administrative agent and issuing bank, KeyBank National Association, as syndication agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on January 15, 2015)
- 10.8 Eclipse Resources Corporation 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on June 24, 2014)
- 10.9 Master Reorganization Agreement, dated June 6, 2014, by and among Eclipse Resources I, LP, Eclipse GP, LLC, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P., Eclipse Management, L.P., Eclipse Resources Holdings, L.P., Eclipse Resources Corporation and Benjamin W. Hulburt, Christopher K. Hulburt and Thomas S. Liberatore (incorporated by reference to Exhibit 10.9 to Amendment No. 2 to the Company's Registration Statement on Form S-1 filed with the SEC on June 9, 2014)
- 10.10 Form of Indemnification Agreement for Eclipse Resources Corporation Officers and Directors (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to the Company's Registration Statement on Form S-1 filed with the SEC on June 2, 2014)
- 10.11 Agreement of Limited Partnership of Eclipse Resources Holdings, L.P. (incorporated by reference to Exhibit 10.13 to Amendment No. 2 to the Company's Registration Statement on Form S-1 filed with the SEC on June 9, 2014)
- 10.12 Limited Partnership Agreement of Eclipse Management, L.P. (incorporated by reference to Exhibit 10.14 to Amendment No. 2 to the Company's Registration Statement on Form S-1 filed with the SEC on June 9, 2014)
- 10.13 Executive Employment Agreement dated as of August 26, 2014, by and between Eclipse Resources Corporation and Benjamin W. Hulburt (incorporated by referenced to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 29, 2014)
- 10.14 Executive Employment Agreement dated as of August 26, 2014, by and between Eclipse Resources Corporation and Matthew R. DeNezza (incorporated by referenced to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on August 29, 2014)
- 10.15 Executive Employment Agreement dated as of August 26, 2014, by and between Eclipse Resources Corporation and Christopher K. Hulburt (incorporated by referenced to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the SEC on August 29, 2014)
- 10.16 Executive Employment Agreement dated as of August 26, 2014, by and between Eclipse Resources Corporation and Thomas S. Liberatore (incorporated by referenced to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the SEC on August 29, 2014)
- 10.17 Securities Purchase Agreement, dated as of December 27, 2014, by and between Eclipse Resources Corporation, CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P.,

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EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II L.P., GSO Eclipse Holdings I LP, Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP. (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on December 29, 2014)

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10.18	Form of Restricted Stock Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on February 25, 2015)
10.19	Form of Performance Unit Award Agreement for Employees (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on February 25, 2015)
21.1*	List of Subsidiaries of Eclipse Resources Corporation
23.1*	Consent of Grant Thornton LLP
23.2*	Consent of Netherland, Sewell & Associates, Inc.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241)
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241)
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350)
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350)
99.1*	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2014 (Eclipse Resources Corporation)
99.2	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2013 (Eclipse Resources I, LP) (incorporated by reference to Exhibit 99.2 to the Company's Registration Statement on Form S-1 filed with the SEC on May 5, 2014)
99.3	Netherland, Sewell & Associates, Inc., Summary of Reserves at December 31, 2012 (Eclipse Resources I, LP) (incorporated by reference to Exhibit 99.3 to the Company's Registration Statement on Form S-1 filed with the SEC on May 5, 2014)
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document
101.DEF*	XBRL Taxonomy Extension Definition Linkbase Document
101.LAB*	XBRL Taxonomy Extension Label Linkbase Document
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document

* Filed herewith

Compensatory plan or arrangement.

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SIGNATURES

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

March 6, 2015

ECLIPSE RESOURCES CORPORATION
(Registrant)

/s/ Benjamin W . Hulburt
Benjamin W . Hulburt
Chairman, President and Chief Executive Officer

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

Signature

Date

/s/ Benjamin W. Hulburt
Benjamin W. Hulburt

March 6, 2015

Chairman, President and Chief Executive Officer

/s/ Christopher K. Hulburt
Christopher K. Hulburt

March 6, 2015

Executive Vice President, Secretary and General Counsel

/s/ Matthew R. DeNezza
Matthew R. DeNezza

March 6, 2015

Executive Vice President and Chief Financial Officer

/s/Roy Steward
Roy Steward

March 6, 2015

Senior Vice President and Chief Accounting Officer

/s/ D. Martin Phillips
D. Martin Phillips

March 6, 2015

Director

/s/ Robert L. Zorich
Robert L. Zorich

March 6, 2015

Director

/s/ Douglas E. Swanson, Jr.
Douglas E. Swanson, Jr.

March 6, 2015

Director

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Signature	Date
/s/ Mark E. Burroughs, Jr. Mark E. Burroughs, Jr. Director	March 6, 2015
/s/ Joseph C. Winkler, III Joseph C. Winkler, III Director	March 6, 2015
/s/ Richard D. Paterson Richard D. Paterson Director	March 6, 2015
/s/ Randall M. Albert Randall M. Albert Director	March 6, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Eclipse Resources Corporation

We have audited the accompanying consolidated balance sheets of Eclipse Resources Corporation (a Delaware corporation) and subsidiaries (the Company) as of December 31, 2014 and 2013, and the related consolidated statements of operations, comprehensive loss, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2014. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements 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 audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes 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, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Eclipse Resources Corporation as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Cleveland, Ohio

March 6, 2015

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Table of Contents**ECLIPSE RESOURCES CORPORATION****CONSOLIDATED BALANCE SHEETS****(in thousands, except share and per share data)**

	December 31,	
	2014	2013
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	\$ 67,517	\$ 109,509
Accounts receivable	46,378	8,678
Assets held for sale	20,673	
Other current assets	19,711	594
Total current assets	154,279	118,781
PROPERTY AND EQUIPMENT, AT COST		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,044,469	926,812
Proved properties, net	670,255	88,932
Other property and equipment, net	8,103	2,340
Total property and equipment, net	1,722,827	1,018,084
OTHER NONCURRENT ASSETS		
Debt issuance costs, net of \$2.5 million and \$0.8 million of amortization, respectively	6,058	6,570
Other assets	1,782	88
Total other noncurrent assets	7,840	6,658
TOTAL ASSETS	\$ 1,884,946	\$ 1,143,523
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable	\$ 137,415	\$ 29,368
Accrued capital expenditures	51,360	19,200
Accrued liabilities	13,576	4,940
Accrued interest payable	25,187	20,294
Deferred income taxes	5,246	
Accrued liabilities related party		1,951
Total current liabilities	232,784	75,753
NONCURRENT LIABILITIES		
Debt, net of unamortized discount of \$8.5 million and \$10.8 million, respectively	414,016	389,247
Pension obligations	1,321	1,497
Asset retirement obligations	17,400	9,055

Deferred income taxes	66,714	
Total noncurrent liabilities	499,451	399,799
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock, 50,000 shares authorized, no shares issued and outstanding		
Common stock, \$0.01 par value, 1,000,000,000 shares authorized, 160,031,115 and 121,533,408 shares issued and outstanding	1,600	1,215
Additional paid in capital	1,391,004	721,757
Accumulated deficit	(239,345)	(56,169)
Accumulated other comprehensive income (loss)	(548)	1,168
Total stockholders equity	1,152,711	667,971
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	\$ 1,884,946	\$ 1,143,523

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

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ECLIPSE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands except per share data)

	For the year ended December 31,		
	2014	2013	2012
REVENUES			
Oil and natural gas sales	\$ 137,816	\$ 12,935	\$ 370
Total revenues	137,816	12,935	370
OPERATING EXPENSES			
Lease operating	8,518	2,576	16
Transportation, gathering and compression	18,114	67	
Production and ad valorem taxes	7,084	77	1
Depreciation, depletion and amortization	89,218	6,163	404
Exploration	21,186	3,022	4,692
General and administrative	45,392	21,276	4,425
Accretion of asset retirement obligations	791	364	
Impairment of proved oil and gas properties	34,855	2,081	
Gain on sale of assets	(960)		(372)
Gain on reduction of pension obligations	(2,208)		
Total operating expenses	221,990	35,626	9,166
OPERATING LOSS	(84,174)	(22,691)	(8,796)
OTHER INCOME (EXPENSE)			
Gain on derivative instruments	20,791		
Interest income (expense), net	(48,347)	(20,850)	37
Other income	353		
Total other income (expense), net	(27,203)	(20,850)	37
LOSS BEFORE INCOME TAXES	(111,377)	(43,541)	(8,759)
INCOME TAX EXPENSE	71,799		
NET LOSS	\$ (183,176)	\$ (43,541)	\$ (8,759)
NET LOSS PER COMMON SHARE			
Basic and diluted	\$ (1.27)	\$ (0.58)	\$ (0.63)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING			
Basic and diluted	144,369	75,261	13,880

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

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ECLIPSE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in thousands)

	For the Year Ended December 31,		
	2014	2013	2012
NET LOSS	\$ (183,176)	\$ (43,541)	\$ (8,759)
Other comprehensive loss:			
Pension obligation adjustment	(1,716)	1,168	
TOTAL COMPREHENSIVE LOSS	\$ (184,892)	\$ (42,373)	\$ (8,759)

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

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ECLIPSE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF STOCKHOLDER S EQUITY
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013, and 2012

(in thousands, except share and per share data)

	Number of Shares	Common Stock (\$0.01 Par)	Additional Paid-in- Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total
Balances, December 31, 2011	9,583,090	\$ 95	\$ 70,318	\$ (3,869)	\$	\$ 66,544
Capital contributions	9,466,359	95	69,459			69,554
Share-based compensation			3			3
Distributions			(638)			(638)
Net loss				(8,759)		(8,759)
Balances, December 31, 2012	19,049,449	190	139,142	(12,628)		126,704
Capital contributions	102,483,959	1,025	582,572			583,597
Share-based compensation			43			43
Change in accumulated other comprehensive income					1,168	1,168
Net loss				(43,541)		(43,541)
Balances, December 31, 2013	121,533,408	1,215	721,757	(56,169)	1,168	667,971
Capital contributions	16,966,592	170	124,497			124,667
Issuance of restricted stock	31,115					
Share-based compensation			256			256
Pension obligation adjustment					(1,716)	(1,716)
Shares of common stock issued in initial public offering	21,500,000	215	549,810			550,025
Costs related to initial public offering			(5,316)			(5,316)
Net loss				(183,176)		(183,176)

Balances, December 31, 2014	160,031,115	\$ 1,600	\$ 1,391,004	\$ (239,345)	\$ (548)	\$ 1,152,711
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The accompanying notes are an integral part of these consolidated financial statements.

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ECLIPSE RESOURCES CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	For the Year Ended December 31,		
	2014	2013	2012
CASH FLOWS FROM OPERATING ACTIVITIES			
Net loss	\$ (183,176)	\$ (43,541)	\$ (8,759)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities			
Depreciation, depletion and amortization	89,218	6,163	404
Exploration expense	21,186	3,022	4,692
Pension benefit costs	56	575	
Incentive unit compensation	256	43	3
Impairment of proved oil and gas properties	34,855	2,081	
Accretion of asset retirement obligations	791	364	
Gain on reduction of pension liability	(2,208)		
Gain on derivative instruments	(20,791)		
Net cash receipts on settled derivatives	564		
Net cash payments on option premiums	(385)		
Gain on sale of assets	(960)		(372)
Gain on business acquisition	(353)		
Deferred income taxes	71,667		
Interest not paid in cash	15,721	20,294	
Amortization of deferred financing costs	1,744	739	
Amortization of debt discount	2,308	1,247	
Changes in operating assets and liabilities, net of acquisitions:			
Accounts receivable	(33,605)	(5,971)	(172)
Other assets	(1,188)	1,389	50
Accounts payable and accrued liabilities	29,517	27,276	747
Accrued liabilities affiliate	(1,951)	1,569	26
Net cash provided by (used in) operating activities	23,266	15,250	(3,381)
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures for oil and natural gas properties	(745,766)	(252,844)	(179,209)
Additions to other property and equipment	(3,637)	(892)	
Proceeds from the sale of oil and gas properties	15,460	8,497	131,674
Acquisition of business, net of cash acquired	754	(651,847)	
Net cash used in investing activities	(733,189)	(897,086)	(47,535)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from issuance of long-term debt		388,000	

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Debt issuance costs	(1,232)	(7,309)	
Repayments of long-term debt	(213)		
Repayments (borrowings) under revolving credit facility			
Capital contributions	124,667	583,597	69,554
Distributions			(638)
Proceeds from issuance of common stock, net of underwriting fees	550,025		
Initial public offering costs	(5,316)		
Net cash provided by financing activities	667,931	964,288	68,916
Net increase (decrease) in cash and cash equivalents	(41,992)	82,452	18,000
Cash and cash equivalents at beginning of period	109,509	27,057	9,057
Cash and cash equivalents at end of period	\$ 67,517	\$ 109,509	\$ 27,057

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:

Cash paid for interest	\$ 26,020	\$	\$
Cash paid for income taxes	\$	\$	\$

SUPPLEMENTAL DISCLOSURE OF NON-CASH INVESTING AND FINANCING ACTIVITIES:

Asset retirement obligations incurred, including changes in estimate	\$ 7,554	\$ 300	\$
Additions of other property through debt financing	\$ 945	\$	\$
Additions to oil and natural gas properties changes in accounts payable, accrued liabilities, and accrued capital expenditures	\$ 126,656	\$ 17,537	\$ 1,663
Assets and liabilities assumed in acquisition of Eclipse Resources-Ohio, LLC	\$	\$ 5,102	\$
Assets held for sale associated with central gathering facility	\$ 20,673	\$	\$
Interest paid-in-kind	\$ 22,461	\$	\$

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

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ECLIPSE RESOURCES CORPORATION
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
FOR THE YEARS ENDED DECEMBER 31, 2014, 2013 and 2012

Note 1 Organization and Nature of Operations

Eclipse Resources Corporation (the Company) was formed on February 13, 2014, pursuant to the laws of the State of Delaware to become a holding company for Eclipse Resources I, LP (Eclipse I). Eclipse I is engaged in the acquisition and development of oil and natural gas properties in the Appalachian Basin of the United States, which encompasses the Utica Shale and Marcellus Shale prospective areas.

On June 24, 2014 prior to the completion of the IPO, a Corporate Reorganization was completed. As a part of this corporate reorganization the following transactions occurred (collectively, the Corporate Reorganization):

the acquisition by Eclipse I of all of the outstanding equity interests in Eclipse Resources Operating, LLC (Eclipse Operating);

the contribution of equity interests in Eclipse I to Eclipse Resources Holdings, L.P. (Eclipse Holdings) by its then limited partners in exchange for similar equity interests in Eclipse Holdings;

the transfer of the outstanding equity interests in Eclipse I GP, the general partner of Eclipse I, to Eclipse Holdings; and

the contribution of equity interests in Eclipse I and the outstanding equity interests in Eclipse I GP, LLC, to the Company by Eclipse Holdings in exchange for 138,500,000 shares of common stock.

As a result of the Corporate Reorganization, the Company became a majority controlled direct subsidiary of Eclipse Holdings, and Eclipse I became a direct subsidiary of the Company. Each of the transactions that occurred as part of the Corporate Reorganization have been accounted for as a reorganization of entities under common control, with the exception of the acquisition of the outstanding equity interests of Eclipse Operating by Eclipse I, which has been accounted for as a business combination using the acquisition method (See Note 4 *Acquisitions*).

On June 25, 2014, the Company completed the initial public offering (IPO) of 30,300,000 shares of \$0.01 par value common stock, which included 21,500,000 shares sold by the Company and 8,800,000 shares sold by certain selling stockholders.

The gross proceeds to the Company and selling stockholders were approximately \$818.1 million, which resulted in net proceeds to the Company of approximately \$544.7 million after deducting expenses and underwriting discounts and commissions of approximately \$35.8 million. The Company did not receive any proceeds from the sale of the shares by the certain selling stockholders. The net proceeds from the IPO were used to repay all of the then outstanding borrowings under the revolving credit facility and the Company expects to use the remaining net proceeds to fund a portion of the capital expenditure plan.

Note 2 Basis of Presentation

The accompanying consolidated financial statements of Eclipse Resources Corporation for the period from January 1, 2014 through June 23, 2014, as contained within the year ended December 31, 2014 and as of December 31, 2013, and the years ended December 31, 2013 and 2012 pertain to the historical financial statements and results of operations of Eclipse Resources I, LP, our accounting predecessor. In February 2014, Eclipse Resources Corporation was formed as a Delaware corporation for the purpose of becoming a publicly traded company and the holding company of Eclipse I. The historical financial information contained in this report relates to periods that ended prior to the completion of the IPO of Eclipse Resources Corporation. In connection with the completion of the corporate reorganization on June 24, 2014, Eclipse Resources Corporation

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became a holding company whose sole material asset consists of a 100% indirect ownership interest in Eclipse I. As the sole managing member of Eclipse I, Eclipse Resources Corporation is responsible for all operational, management and administrative decisions relating to Eclipse I. Accordingly, this reorganization constituted a common control transaction and the accompanying consolidated financial statements are presented as though this reorganization had occurred for the earliest period presented herein.

The accompanying consolidated financial statements are presented in accordance with the requirements of accounting principles generally accepted in the United States (U.S. GAAP). All significant intercompany accounts have been eliminated in consolidation.

Preparation in accordance with U.S. GAAP requires the Company to (1) adopt accounting policies within accounting rules set by the Financial Accounting Standards Board (FASB) and (2) make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and other disclosed amounts. Note 3 *Summary of Significant Accounting Policies* describes our significant accounting policies. The Company's management believes the major estimates and assumptions impacting the consolidated financial statements are the following:

estimates of proved reserves of oil and natural gas, which affect the calculations of depreciation, depletion and amortization and impairment of capitalized costs of oil and natural gas properties;

estimates of asset retirement obligations;

estimates of the fair value of oil and natural gas properties the Company owns, particularly properties that the Company has not yet explored, or fully explored, by drilling and completing wells;

impairment of undeveloped properties and other assets; and

depreciation and depletion of property and equipment.

Actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions.

Note 3 Summary of Significant Accounting Policies

(a) Cash and Cash Equivalents

Cash and cash equivalents are comprised of cash in banks and highly liquid instruments with original maturities of three months or less, primarily consisting of bank time deposits and investments in institutional money market funds. The carrying amounts approximate fair value due to the short-term nature of these items. Cash in bank accounts at times may exceed federally insured limits.

(b) Accounts Receivable

Accounts receivable are carried at estimated net realizable value. Receivables deemed uncollectible are charged directly to expense. Trade credit is generally extended on a short-term basis, and therefore, accounts receivable do not bear interest, although a finance charge may be applied to such receivables that are past due. A valuation allowance is provided for those accounts for which collection is estimated as doubtful and uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the party. The Company did not deem any of its accounts receivables to be uncollectable as of December 31, 2014 or December 31, 2013.

The Company accrues revenue due to timing differences between the delivery of natural gas, natural gas liquids (NGLs), and crude oil and the receipt of a delivery statement. These revenues are recorded based upon

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volumetric data from the Company's records and management's estimates of the related commodity sales and transportation and compression fees which are, in turn, based upon applicable product prices. The Company had \$24.1 million and \$4.1 million of accrued revenues, net of expenses at December 31, 2014 and December 31, 2013, respectively, which were included in accounts receivable within the Company's consolidated balance sheets.

(c) Property and Equipment*Oil and Natural Gas Properties*

The Company follows the successful efforts method of accounting for its oil and natural gas operations. Acquisition costs for oil and natural gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense (see *Depreciation, Depletion and Amortization* below).

Costs incurred to acquire producing and non-producing leaseholds are capitalized. All unproved leasehold acquisition costs are initially capitalized, including the cost of leasing agents, title work and due diligence. If the Company acquires leases in a prospective area, these costs are capitalized as unproved leasehold costs. If no leases are acquired by the Company with respect to the initial costs incurred or the Company discontinues leasing in a prospective area, the costs are charged to exploration expense. Unproved leasehold costs that are determined to have proved oil and gas reserves are transferred to proved leasehold costs.

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Company's consolidated statements of operations. Upon the sale of an individual well, the proceeds are credited to accumulated depreciation and depletion within the Company's consolidated balance sheets. Upon sale of an entire interest in an unproved property where the property had been assessed for impairment individually, a gain or loss is recognized in the Company's consolidated statements of operations. If a partial interest in an unproved property is sold, any funds received are accounted for as a reduction of the cost in the interest retained.

A summary of property and equipment including oil and natural gas properties is as follows (in thousands):

	December 31, 2014	December 31, 2013
Oil and natural gas properties:		
Unproved	\$ 1,044,469	\$ 926,812
Proved	802,112	97,528
Gross oil and natural gas properties	1,846,581	1,024,340
Less accumulated depreciation, depletion and amortization	(131,857)	(8,596)
Oil and natural gas properties, net	1,714,724	1,015,744
Other property and equipment	8,912	2,392

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Less accumulated depreciation	(809)	(52)
Other property and equipment, net	8,103	2,340
Property and equipment, net	\$ 1,722,827	\$ 1,018,084

Exploration expenses, including geological and geophysical expenses and delay rentals for unevaluated oil and gas properties are charged to expense as incurred. Exploratory drilling costs are initially capitalized as unproved property, not subject to depletion, but charged to expense if and when the well is determined not to have found proved oil and gas reserves.

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Other property and equipment include land, buildings, leasehold improvements, vehicles, computer equipment and software, telecommunications equipment, and furniture and fixtures. These items are recorded at cost, or fair value if acquired through a business acquisition.

(d) Revenue Recognition

Oil and natural gas sales revenue is recognized when produced quantities of oil and natural gas are delivered to a custody transfer point such as a pipeline, processing facility or a tank lifting has occurred, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sales is reasonably assured and the sales price is fixed or determinable. Revenues from the sales of natural gas, crude oil or NGLs in which the Company has an interest with other producers are recognized using the sales method on the basis of the Company's net revenue interest. The Company had no material imbalances as of December 31, 2014 and December 31, 2013.

In accordance with the terms of joint operating agreements, from time to time, the Company may be paid monthly fees for operating or drilling wells for outside owners. The fees are meant to recoup some of the operator's general and administrative costs in connection with well and drilling operations and are accounted for as credits to general and administrative expense.

(e) Major Customers

The Company sells production volumes to various purchasers. For the years ended December 31, 2014, 2013 and 2012, there were two, four, and one customer that accounted for 10% or more of the total natural gas, NGLs and oil sales. Management believes that the loss of any one customer would not have an adverse effect on the Company's ability to sell natural gas, NGLs and oil production. The following table sets forth the Company's major customers and associated percentage of revenue for the periods indicated:

	For the Year Ended December 31,		
	2014	2013	2012
Purchaser			
Antero Resources Corporation	47%	38%	100%
Devco Oil Inc.		24%	
Dominion Resources Inc.		13%	
ARM Energy Management	25%		
Ergon		12%	
Total	72%	87%	100%

Management believes that there are potential alternative purchasers and that it may be necessary to establish relationships with new purchasers. However, there can be no assurance that the Company can establish such relationships or that those relationships will result in an increased number of purchasers. Although the Company is exposed to a concentration of credit risk, management believes that all of the Company's purchasers are credit worthy.

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The following table summarizes concentration of receivables, net of allowances, by product or service as of December 31, 2014 and December 31, 2013 (in thousands):

	December 31, 2014	December 31, 2013
Receivables by product or service:		
Sale of oil and natural gas and related products and services	\$ 22,777	\$ 4,092
Joint interest owners	20,666	4,586
Miscellaneous other	2,935	
Total	\$ 46,378	\$ 8,678

Oil and natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the State of Ohio. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, the Company exposes itself to the credit risk of counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company's policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The creditworthiness of the Company's counterparties is subject to periodic review. The fair value of the Company's commodity derivative contracts is a net asset position of \$19.0 million at December 31, 2014. Other than as provided by the revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under the Company's contracts, nor are they required to provide credit support to the Company. As of December 31, 2014, the Company did not have past-due receivables from or payables to any of the counterparties.

(g) Accumulated Other Comprehensive Income (Loss)

Comprehensive loss includes net loss and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net loss. These changes, other than net loss, are referred to as other comprehensive loss and for the Company they include a pension benefit plan that requires the Company to (i) recognize the overfunded or underfunded status of a defined benefit retirement plan as an asset or liability in its balance sheet and (ii) recognize changes in that funded status in the year in which the changes occur through other comprehensive loss. The Company's pension plan was underfunded by \$1.3 million and \$1.5 million at December 31, 2014 and December 31, 2013, respectively. Effective March 31, 2014, benefit accruals in the plan were frozen resulting in a gain on reduction of pension liability of \$2.2 million for the year ended December 31, 2014. No such gain was recorded for the year ended December 31, 2013.

(h) Depreciation, Depletion and Amortization

Oil and Natural Gas Properties

Depreciation, depletion, and amortization (DD&A) of capitalized costs of proved oil and natural gas properties is computed using the unit-of-production method on a field level basis using total estimated proved reserves. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate DD&A for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves. DD&A expense relating to proved

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oil and natural gas properties for the years ended December 31, 2014, 2013 and 2012 totaled approximately \$88.4 million, \$5.9 million and \$0.2 million, respectively.

Through September 30, 2014, the Company calculated depletion of proved properties at the individual unit level. Effective October 1, 2015, the Company changed its estimate for calculating depletion expense of proved properties to be performed at the field level consistent with the assessment for impairment of proved property costs. As a result of this change, DD&A expense recorded by the Company for the year ended December 31, 2014 was \$1.3 million lower than it would have been if the Company had not made this change.

Other Property and Equipment

Depreciation with respect to other property and equipment is calculated using straight-line methods based on expected lives of the individual assets or groups of assets ranging from 5 to 40 years. Depreciation for the years ended December 31, 2014, 2013, and 2012 totaled approximately \$0.8 million, \$0.3 million and \$0.2 million, respectively. This amount is included in DD&A expense in the consolidated statements of operations.

(i) Impairment of Long-Lived Assets

The Company reviews its long lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If it is determined that an asset's estimated future cash flows will not be sufficient to recover its carrying amount, an impairment charge will be recorded to reduce the carrying amount for that asset to its estimated fair value if such carrying amount exceeds the fair value.

During the year ended December 31, 2014, the Company changed its estimate for assessing impairment of proved property costs. Through September 30, 2014, such assessments were performed at the individual unit level. Effective October 1, 2014, assessment for impairment of proved properties is performed at the field level, which for the Company consists of three fields, including Conventional production, the Utica Shale, and the Marcellus Shale. With the increase in the Company's activity level, this change will result in a more appropriate identification of cash flows utilized in the assessment of recoverability of proved properties as additional units are placed into production, resulting in increased sharing of revenues and costs across units related to infrastructure, equipment, and fulfillment of sales and transportation contracts.

The review of the Company's oil and gas properties is done by determining if the historical cost of proved properties less the applicable accumulated DD&A and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company's plans to continue to produce and develop proved reserves and a risk-adjusted portion of probable reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Company estimates prices based upon current contracts in place, adjusted for basis differentials and market-related information, including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. The Company recognized impairment expenses relating to proved properties of \$34.9 million and \$2.1 million for the years ended December 31, 2014 and 2013, respectively. Approximately \$30.9 million of the impairment recorded for the year ended December 31, 2014 was recorded during the fourth quarter of 2014 as a result of the significant decline in oil and natural gas commodity prices during the quarter related to the conventional properties acquired during the Oxford Acquisition. The remaining \$4.0 million related to unconventional properties in the Utica Shale. There were no impairments of proved properties for the year ended December 31, 2012.

The aforementioned impairment charges represented a significant Level 3 measurement in the fair value hierarchy. The primary input used was the Company's forecasted discount net cash flows.

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The determination of oil and natural gas reserve estimates is a subjective process, and the accuracy of any reserve estimate depends on the quality of available data and the application of engineering and geological interpretation and judgment. Estimates of economically recoverable reserves and future net cash flows depend on a number of variable factors and assumptions that are difficult to predict and may vary considerably from actual results.

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment charge is recorded if conditions indicate the Company will not explore the acreage prior to expiration of the applicable leases. The Company recorded impairment charges of unproved oil and gas properties related to lease expirations of \$5.7 million and \$0.8 million for the years ended December 31, 2014 and 2012, respectively. These costs are included in exploration expense in the consolidated statements of operations. No such impairments were recorded for year ended December 31, 2013.

(j) Income Taxes

The Company accounts for income taxes, as required, under the liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry-forwards. 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 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. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Upon the closing of the Corporate Reorganization, the Company owns 100% of Eclipse I, Eclipse Resources-Ohio, LLC and Eclipse Operating. Eclipse I was a limited partnership not subject to federal income taxes before the Corporate Reorganization. However, in connection with the closing of the Corporate Reorganization, the Company became a corporation subject to federal and state income tax and, as such, the Company's future income taxes will be dependent upon its future taxable income. The change in tax status requires the recognition of a deferred tax asset or liability for the initial temporary differences at the time of the change in status. The resulting net deferred tax liability of approximately \$97.6 million was recorded as income tax expense in the consolidated statements of operations for the year ended December 31, 2014.

The FASB's Accounting Standards Codification (ASC) Topic 740 *Income Taxes* provides that a tax benefit from an uncertain tax position may be recognized when it is more likely than not that the position will be sustained upon examination, including resolutions of any related appeals or litigation processes, based on the technical merits. Income tax positions must meet a more-likely-than-not recognition threshold at the effective date to be recognized upon the adoption of the uncertain tax position guidance and in subsequent periods. This interpretation also provides guidance on measurement, derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. The Company recognizes fines and penalties as income tax expense.

(k) Fair Value of Financial Instruments

The Company has established a hierarchy to measure its financial instruments at fair value which requires it to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The hierarchy defines three levels of inputs that may be used to measure fair value:

Level 1 Unadjusted quoted prices in active markets for identical, unrestricted assets and liabilities that the reporting entity has the ability to access at the measurement date.

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Level 2 Inputs other than quoted prices included within Level 1 that are observable for the asset and liability or can be corroborated with observable market data for substantially the entire contractual term of the asset or liability.

Level 3 Unobservable inputs that reflect the entity's own assumptions about the assumption market participants would use in the pricing of the asset or liability and are consequently not based on market activity but rather through particular valuation techniques.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy.

(l) Derivative Financial Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of the energy commodities it sells.

Derivatives are recorded at fair value and are included on the consolidated balance sheets as current and noncurrent assets and liabilities. Derivatives are classified as current or noncurrent based on the contractual expiration date. Derivatives with expiration dates within the next 12 months are classified as current. The Company netted the fair value of derivatives by counterparty in the accompanying consolidated balance sheets where the right to offset exists. The Company's derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. Premiums for options are included in cash flows from operating activities.

The valuation of the Company's derivative financial instruments represents a Level 2 measurement in the fair value hierarchy.

(m) Asset Retirement Obligation

The Company recognizes a legal liability for its asset retirement obligations (ARO) in accordance with Topic ASC 410, *Asset Retirement and Environmental Obligations*, associated with the retirement of a tangible long-lived asset, in the period in which it is incurred or becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The Company measures the fair value of its ARO using expected future cash outflows for abandonment discounted back to the date that the abandonment obligation was measured using an estimated credit adjusted rate, which was 9.89% and 8.96% for the years ended December 31, 2014 and 2013, respectively.

Estimating the future ARO requires management to make estimates and judgments based on historical estimates 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. As of December 31, 2014, management revised its assumptions relating to certain wells including useful lives, working interest, and abandonment costs. These revisions increased the asset

retirement obligation for the wells, and as a result, the Company recorded an incremental layer of approximately \$6.5 million.

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The following table sets forth the changes in the Company's ARO liability for the period indicated (in thousands):

	2014	2013	2012
Asset retirement obligations, beginning of period	\$ 9,055	\$ 13	\$
Revisions of prior estimates	6,470		
Additional liabilities incurred	1,084	300	13
Assumption of Oxford asset retirement obligations		8,378	
Accretion	791	364	
Asset retirement obligations, end of period	\$ 17,400	\$ 9,055	\$ 13

The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to ARO represent a significant nonrecurring Level 3 measurement.

(n) Lease Obligations

The Company leases office space under operating leases that expire between the years 2015–2025. The lease terms begin on the date of initial possession of the leased property for purposes of recognizing lease expense on a straight-line basis over the term of the lease. The Company does not assume renewals in its determination of the lease terms unless the renewals are deemed to be reasonably assured at lease inception.

(o) Off-Balance Sheet Arrangements

The Company does not have any off-balance sheet arrangements.

(p) Segment Reporting

The Company operates in one industry segment: the oil and natural gas exploration and production industry in the United States. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

(q) Debt Issuance Costs

The expenditures related to issuing debt are capitalized and included in other assets in the accompanying balance sheets. These costs are amortized over the expected life of the related instruments using the effective interest rate method. When debt is retired before maturity or modifications significantly change the cash flows, related unamortized costs are expensed.

(r) Recent Accounting Pronouncements

The FASB issued ASU 2013-11, *Income Taxes (Topic 740) Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward, a Similar Tax Loss, or a Tax Credit Carryforward Exists* in December 2013. These amendments provide that an unrecognized tax benefit, or a portion thereof, should be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward, except to the extent that a net operating loss carryforward, a similar tax loss, or a tax credit carryforward

is not available at the reporting date to settle any additional income taxes that would result from disallowance of a tax position, or the tax law does not require the entity to use, and the entity does not intend to use, the deferred tax asset for such purpose, then the unrecognized tax benefit should be presented as a liability. These requirements were effective for annual reporting periods beginning after

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December 15, 2013, including interim periods within that reporting period. The adoption of this ASU did not impact the Company's financial position, results of operations or liquidity.

The FASB issued ASU 2014-09, *Revenue from Contracts with Customers (Topic 606) (Update 2014-09)*, which supersedes the revenue recognition requirements (and some cost guidance) in Topic 605, Revenue Recognition, and most industry-specific guidance throughout the industry topics of the Accounting Standards Codification. In addition, the existing requirements for the recognition of a gain or loss on the transfer of nonfinancial assets that are not in a contract with a customer (for example, assets within the scope of Topic 360, Property, Plant and Equipment, and intangible assets within the scope of Topic 350, Intangibles—Goodwill and Other) are amended to be consistent with the guidance on recognition and measurement (including the constraint on revenue) in Update 2014-09. Topic 606 requires an entity to recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this, an entity should identify the contract with a customer, identify the performance obligations in the contract, determine the transaction price, allocate the transaction price to the performance obligations in the contract and recognize revenue when (or as) the entity satisfies the performance obligations. These requirements are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

In June 2014, the FASB issued ASU 2014-12, *Compensation—Stock Compensation (Topic 718) (Update 2014-12)*. The amendments in Update 2014-12 require that a performance target that affects vesting and that could be achieved after the requisite service period, be treated as a performance condition. As such, the performance target should not be reflected in estimating the grant date fair value of the award. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved and should represent the compensation cost attributable to the period(s) for which the requisite service has already been rendered. If the performance target becomes probable of being achieved before the end of the requisite service period, the remaining unrecognized compensation cost should be recognized prospectively over the remaining requisite service period. The total amount of compensation cost recognized during and after the requisite service period should reflect the number of awards that are expected to vest and should be adjusted to reflect those awards that ultimately vest. The requisite service period ends when the employee can cease rendering service and still be eligible to vest in the award if the performance target is achieved. The amendments in Update 2014-12 are effective for annual periods and interim periods within those annual periods beginning after December 15, 2015. Earlier adoption is permitted. Entities may apply the amendments in Update 2014-12 either (a) prospectively to all awards granted or modified after the effective date, or (b) retrospectively to all awards with performance targets that are outstanding as of the beginning of the earliest annual period presented in the financial statements and to all new or modified awards thereafter. The Company will adopt the requirements of Update 2014-12 upon its effective date of January 1, 2016, and is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

In April 2014, the FASB issued ASU 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) : Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity*. The objective of the amendments in this update is to change the criteria for reporting discontinued operations and enhance convergence of the FASB's and the International Accounting Standard Board's (IASB) reporting requirements for discontinued operations. The amendments in this update change the requirements for reporting discontinued operations in Subtopic 205-20. A discontinued operation may include a component of an entity or a group of components of an entity, or a business or nonprofit activity. A disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results. The amendments in this update require an entity to present, for each comparative period, the assets and liabilities of a disposal group that

includes a discontinued operation separately in the asset and liability sections, respectively, of the statement of financial position. The amendments in this update also require additional disclosures about discontinued operations. Public business entities must apply the

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amendments in this update prospectively to both of the following: (1) All disposals (or classifications as held for sale) of components of an entity that occur within annual periods beginning on or after December 15, 2014, and interim periods within those years; (2) All businesses or nonprofit activities that, on acquisition, are classified as held for sale that occur within annual periods beginning on or after December 15, 2014, and interim periods within those years. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

In August 2014, the FASB issued Accounting Standards Update No. 2014-15, *Presentation of Financial Statements Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern*. The new standard provides guidance on determining when and how to disclose going concern uncertainties in the financial statements. Management will be required to perform interim and annual assessments of the Company's ability to continue as a going concern within one year of the date and financial statements are issued. ASU 2014-15 is effective for annual periods ending after December 15, 2016, and interim periods within those years, with early adoption permitted. The adoption of this standard is not expected to have an impact on the Company's financial statement disclosures.

Note 4 Acquisition***Eclipse Resources Operating, LLC Acquisition***

On June 24, 2014, prior to the closing of the IPO, the Company acquired all of the outstanding equity interests of Eclipse Operating for total consideration of \$0.1 million. The fair value of the net assets acquired, consisting primarily of cash, accounts receivable, property and equipment, accounts payable and accrued liabilities exceeded the purchase price paid. As a result, the Company recognized a gain of \$0.4 million related to the purchase, which is included in other income on the consolidated statements of operations.

The Eclipse Resources-Ohio, LLC Acquisition

On June 26, 2013, Eclipse I acquired (the Oxford Acquisition) 100% of the outstanding equity interests of Oxford. Oxford held interests in approximately 181,000 net acres of Utica Shale leaseholds, and related producing properties located primarily in Belmont, Guersney, Monroe, Noble, and Harrison Counties in Ohio along with various other related rights, permits, contracts, equipment and other assets. The aggregate purchase price totaled \$652.5 million in cash. The acquisition provided strategic additions adjacent to the Company's core project area.

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The Purchase and Sales Agreement (PSA) for the Oxford Acquisition contained customary closing conditions and a \$32.5 million escrow which was withheld from the initial purchase price to provide for certain contingencies. The notice period for any claims related to these contingencies expired June 25, 2014 and all amounts were released from escrow to the seller. The acquisition is accounted for using the acquisition method under ASC Topic 805, *Business Combinations* which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of July 26, 2013. The following table summarizes the purchase price allocation and the values of assets acquired and liabilities assumed (in thousands):

Purchase Price	June 26, 2013
Consideration Given	
Cash	\$ 652,500
Allocation of Purchase Price	
Unproved properties	621,039
Proved properties	40,914
Cash	653
Building and land	1,500
Total assets	664,106
Asset retirement obligations	(8,378)
Pension obligation	(2,522)
Other working capital	(706)
Fair value of net assets acquired	\$ 652,500

The purchase price allocation set forth above represented a significant Level 3 measurement in the fair value hierarchy and was derived in accordance with ASC 805 by an outside third party. The inputs used in such determination were forecasted cash flows, market comparisons, actuarial studies and Oxford's historical accounting records.

Immediately prior to the completion of the Oxford Acquisition, Oxford merged into Eclipse Resources Ohio, LLC (Eclipse Ohio). Eclipse Ohio is party to various lawsuits, primarily related to the validity of certain oil and gas leases (see Note 13 *Commitments and Contingencies*).

Table of Contents*Pro Forma Financial Information (unaudited)*

The following unaudited pro forma financial information represents the combined results for the Company and Oxford for the years ended December 31, 2013 and 2012 as if the acquisition had occurred on January 1, 2012. The pro forma information includes the effects of adjustments for depletion, depreciation, amortization and accretion expense of \$3.4 million and \$0.8 million for the years ended December 31, 2013 and 2012, respectively. The pro forma information includes the effects of adjustments for amortization of financing costs of \$0.7 million and \$1.5 million for the years ended December 31, 2013 and 2012, respectively. The pro forma information includes the effects of the amortization of debt discount of \$1.2 million and \$2.4 million for the years ended December 31, 2013 and 2012, respectively. The pro forma information includes the effects of the incremental interest expense on acquisition financing of \$26.9 million and \$53.9 million for the years ended December 31, 2013 and 2012, respectively. The pro forma results do not include any cost savings or other synergies that may result from the acquisition or any estimated costs that have been or will be incurred by the Company to integrate the properties acquired. The pro forma results are not necessarily indicative of what actually would have occurred if the acquisition had been completed as of January 1, 2012, nor are they necessarily indicative of future results (in thousands).

	For the Year Ended December 31,	
	2013	2012
Oil and natural gas sales	\$ 20,638	\$ 13,936
Net loss	\$ (71,131)	\$ (56,065)

Note 5 Sale of Oil and Natural Gas Property Interests

Effective March 16, 2012, the Partnership entered into a Purchase and Exploration Agreement (PEA) to sell 70% of its interests in certain unproved oil and gas properties. During 2012, the Partnership completed the sale of 21,114 net acres under the PEA for net proceeds of \$126.5 million. The cumulative proceeds of the sale did not exceed the Partnership's cost basis in the properties; therefore, no gain was recognized on the sale.

During the year ended December 31, 2012, the Partnership sold 70% of its interest in a proved oil and gas property for \$5.2 million, before customary purchase price adjustments. The proceeds included \$2.4 million for the sale of 70% of its net acreage in the unit and \$2.8 million for the reimbursement of 70% of the Partnership's net drilling costs incurred. The sales proceeds exceeded the Partnership's cost basis in the unit, resulting in a gain of \$0.4 million during 2012.

During the year ended December 31, 2013, the Partnership sold an additional 1,220 acres for net proceeds of \$8.5 million. The cumulative proceeds of the sale did not exceed the Partnership's cost basis in the properties; therefore, no gain was recognized on the sale.

During the year ended December 31, 2014, the Company sold a central processing facility for proceeds of \$16.8 million, of which \$15.5 million had been received by December 31, 2014. The proceeds exceeded the Company's cost basis in the facility, resulting in a gain of approximately \$1.0 million during 2014.

As of December 31, 2014, the Company was actively negotiating the sale of a second central processing facility, which is expected to close during 2015. As a result, costs related to this facility of approximately \$20.7 million are classified as assets held for sale in the consolidated balances sheets as of December 31, 2014.

Table of Contents**Note 6 Derivative Instruments***Commodity derivatives*

The Company is exposed to market risk from changes in energy commodity prices within its operations. The Company utilizes derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas. The Company currently uses a mix of over-the-counter (OTC) natural gas fixed price swaps, basis swaps and put options spreads and collars to manage its exposure to natural gas price fluctuations. All of the Company's derivative instruments are used for risk management purposes and none are held for trading or speculative purposes.

The Company is exposed to credit risk in the event of non-performance by counterparties. The creditworthiness of counterparties is subject to continuing review. The Company has not experienced any issues of non-performance by derivative counterparties.

Below is summary of the Company's derivative instrument positions, as of December 31, 2014, for future production periods:

Description	Volume (MMBtu/d)	Production Period		Weighted Average Price (\$/MMBtu)	
Natural Gas Swaps:					
	66,219	January 2015	December 2015	\$	3.797
	25,000	January 2016	December 2016	\$	3.660
Natural Gas Three-way Collar:					
Floor purchase price (put)	15,000	January 2015	December 2015	\$	3.60
Ceiling sold price (call)	15,000	January 2015	December 2015	\$	3.80
Floor sold price (put)	15,000	January 2015	December 2015	\$	3.00
Natural Gas Put Sale:					
Put sold	16,800	January 2015	December 2015	\$	3.350
Natural Gas Collar:					
Purchased put	5,000	January 2015	March 2015	\$	4.000
Call sold	5,000	January 2015	March 2015	\$	4.750
Basis Swaps:					
	25,000	January 2015	March 2015	\$	(1.067)
	25,000	April 2015	October 2015	\$	(1.208)

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The following table summarizes the fair value of the Company's derivative instruments on a gross basis and on a net basis as presented in the consolidated balance sheets (in thousands). None of the derivative instruments are designated as hedges for accounting purposes.

Derivatives not designated as hedging instruments under ASC 815	Gross Amount	Netting Adjustments(a)	Net Amount Presented in the Balance Sheets	Balance Sheet Location
As of December 31, 2014				
Assets				
Commodity derivatives current	\$ 22,349	\$ (5,012)	\$ 17,337	Other current assets
Commodity derivatives noncurrent	1,741	(44)	1,697	Other assets
Total assets	\$ 24,090	\$ (5,056)	\$ 19,034	
Liabilities				
Commodity derivatives current	\$ (5,012)	\$ 5,012	\$	
Commodity derivatives noncurrent	(44)	44	\$	
Total liabilities	\$ (5,056)	\$ 5,056	\$	

(a) The Company has agreements in place that allow for the financial right to offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

At December 31, 2013, the Company did not have any derivative instruments in place.

The following table presents the Company's reported gains and losses on derivative instruments and where such values are recorded in the consolidated statements of operations for the periods presented (in thousands):

	Location of Gain (Loss)	Years Ended December 31,		
		2014	2013	2012
Commodity derivatives	Gain on derivative instruments	\$ 20,791	\$	\$

Note 7 Fair Value Measurements*Fair Value Measurement on a Recurring Basis*

The following table presents, by level within the fair value hierarchy, the Company's assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the consolidated balance sheets for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

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The fair value of the Company's derivatives is based on third-party pricing models which utilize inputs that are readily available in the public market, such as natural gas forward curves. These values are compared to the values given by counterparties for reasonableness. Since natural gas swaps do not include optionality and therefore generally have no unobservable inputs, they are classified as Level 2.

	Level 1	Level 2	Level 3	Total Fair Value
As of December 31, 2014: (in thousands)				
Commodity derivative instruments	\$	\$ 19,034	\$	\$ 19,034
Total	\$	\$ 19,034	\$	\$ 19,034

The Company did not have any assets or liabilities that were measured at fair value on a recurring basis as of December 31, 2013, except for pension assets as described in Note 9.

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Table of Contents***Nonfinancial Assets and Liabilities***

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company's estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine the inception value of the Company's AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company's ARO represent a nonrecurring Level 3 measurement. (See Note 3(m)).

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. (See Note 3(i)).

The estimated fair values of the Company's financial instruments closely approximate the carrying amounts due, except for long-term debt. (see Note 8 *Debt*)

Note 8 Debt***12% Senior Unsecured PIK Notes Due 2018***

On June 26, 2013, Eclipse I completed a private placement offering of an initial aggregate principal amount of \$300 million, with an additional \$100 million notes option, at the discretion of Eclipse I, of 12% Senior Unsecured PIK Notes due in 2018 (the Senior Unsecured Notes). The Senior Unsecured Notes were issued at 96% of par and Eclipse I received \$280.7 million of net cash proceeds, after deducting the discount to initial purchasers of \$12 million and offering expenses of \$7.3 million. In December 2013, Eclipse I exercised its option and issued an additional \$100 million of Senior Unsecured Notes with the same terms, at par. Eclipse I received \$100 million net cash proceeds, as no discounts and \$0.2 million of offering expenses were incurred in connection with the exercise of the option. During the year ended December 31, 2014, the Company amortized \$4.1 of deferred financing costs and debt discount to interest expense using the effective interest method.

The Company has the right to redeem all or a portion of the Senior Unsecured Notes prior to the 2-year anniversary of the final funding date, which the Company refers to as the Non-Call Period, by paying a redemption price equal to 100.0% times a make whole premium equal to the greater of 106.0% or an amount computed under the Indenture governing the Senior Unsecured Notes (the Indenture) plus accrued and unpaid interest. After the Non-Call Period, the Company may redeem all or a part of the Senior Unsecured Notes at the redemption prices (expressed as percentages of principal amount) set forth below, plus accrued and unpaid interest:

Year following expiration of the Non-Call Period	Redemption Price
Year 1	106.00%
Year 2	103.00%
Year 3 and thereafter	100.00%

At the Company's option, for the first 2 semi-annual interest payments following the issue date, interest may be payable by increasing the principal amount of the Senior Unsecured Notes or by issuing payment in kind (PIK) securities. Interest paid by issuing PIK securities accrues at 13%, interest paid by cash accrues at 12%. At the Company's option, for the subsequent four semi-annual interest payments thereafter, interest may be

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payable in the form of 6.0% per annum in cash and 7.0% per annum in PIK securities. Thereafter, interest can only be paid as cash interest. Interest is payable on July 15 and January 15 each year, beginning in January 2014. The Company elected to settle its accrued interest payable on January 15, 2014 by issuing PIK securities of \$22.5 million and settle its accrued interest payable on July 15, 2014 with a cash payment of \$25.3 million. The Company elected to settle its accrued interest payable on January 15, 2015 by issuing PIK securities of \$14.8 million and a cash payment of \$12.7 million.

The Company's obligations under the Senior Unsecured Notes are guaranteed by its 100% owned subsidiaries. The Company may not among other things, directly or indirectly: (1) consolidate or merge with or into another Person (whether or not the Company is the survivor), or (2) sell, assign, transfer, convey, lease or otherwise dispose of all or more than 50% of its properties or assets, in one or more related transactions, to another Person, unless in each case certain restrictive conditions contained in the Indenture are met.

The Indenture requires the Company to be in compliance with certain other covenants, including the prompt payment of interest, including PIK interest, and any and all material taxes, assessments and government levies imposed; timely submission of quarterly and audited annual financial statements, reserve reports, budgets and other notices, and other recurring obligations. The Indenture places restrictions on the Company and its subsidiaries with respect to additional indebtedness, liens, dividends and other payments, investments, acquisitions, mergers, asset dispositions, transactions with affiliates, change of control and other matters. The Company was in compliance with all applicable covenants in the Indenture at December 31, 2014.

The Senior Unsecured Notes are subject to certain events of default. If an event of default occurs and is continuing, the outstanding Senior Notes may, and under certain circumstances, will be accelerated. The purchasers of the Senior Notes are entitled to the benefits of a registration rights agreement pursuant to which the Company agreed to file a registration statement with the Securities and Exchange Commission to allow for the resale of the Notes under the Securities Act.

As of December 31, 2014, the principal amount outstanding related to the Senior Unsecured Notes was \$422.5 million. The fair value of the Senior Unsecured Notes as of December 31, 2014 was \$482.8 million. This fair value estimate is classified as Level 2 in the fair value hierarchy. The valuation techniques used are industry-standard models that consider various assumptions, including quoted forward rates, time value, volatility factors and current market and contractual rates, as well as other relevant economic measures. Substantially all of the assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data, or are supported by observable levels at which transactions are executed in the marketplace.

Revolving Credit Facility

During the first quarter of 2014, the Company entered into a \$500 million senior secured revolving bank credit facility (the Revolving Credit Facility) that matures in 2018. Borrowings under the Revolving Credit Facility are subject to borrowing base limitations based on the collateral value of the Company's proved properties and commodity hedge positions and are subject to quarterly redeterminations through April 1, 2015 and semiannual redeterminations thereafter. At December 31, 2014, the borrowing base was \$100 million and the Company had no outstanding borrowings. After considering outstanding letters of credit issued by the Company, totaling \$26.9 million, the Company had available capacity on the Revolving Credit Facility of \$73.1 million at December 31, 2014. In March 2015, the borrowing base of the Revolving Credit Facility was redetermined, resulting in an increase in the borrowing base to \$125 million.

The Revolving Credit Facility was amended and restated on January 12, 2015. The primary change effected by the Amendment was to add Eclipse Resources Corporation as a party to the Revolving Credit Facility and thereby subject the Company to the representations, warranties, covenants and events of default provisions thereof. Relative to the Eclipse I s previous credit agreement, the Credit Agreement also (i) requires financial reporting regarding, and tests financial covenants with respect to, Eclipse Resources Corporation rather than

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Eclipse I, (ii) increases the basket sizes under certain of the negative covenants, and (iii) includes certain other changes favorable to Eclipse I. Other terms of the Credit Agreement remain generally consistent with Eclipse I's previous credit agreement.

The Revolving Credit Facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's operating subsidiaries. The Revolving Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company was in compliance with all applicable covenants under the Revolving Credit Facility as of December 31, 2014. Commitment fees on the unused portion of the Revolving Credit Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused facility based on utilization.

Note 9 Benefit Plans

Defined Contribution Plan

The Company currently maintains a retirement plan intended to provide benefits under section 401(K) of the Internal Revenue Code, under which employees are allowed to contribute portions of their compensation to a tax-qualified retirement account. Under the 401(K) plan, the Company provides matching contributions equal to 100% of the first 6% of employees' eligible compensation contributed to the plan. The Company contributed \$0.4 million, \$0.2 million and \$0.1 million in matching contributions for the years ended December 31, 2014, 2013 and 2012, respectively.

Defined Benefit Plan

The Company maintains a defined benefit pension plan covering 28 of its employees, of which two are retired, four have deferred vested termination, and one is a survivor. Benefits are based on the employee's years of service and compensation. The Partnership's plans are funded in conformity with the funding requirements of ASC 715 as of December 31, 2014. As a result of the Oxford acquisition (refer to Note 4 above) on June 26, 2013, the Partnership assumed the defined benefit pension plan, and therefore, no pension benefit plan was in effect prior to such date. Effective March 31, 2014, benefit accruals in the plan were frozen resulting in a gain on reduction of pension liability of \$2.2 million for the year ended December 31, 2014.

The authoritative guidance for defined benefit pension plans requires an employer to recognize the overfunded or underfunded status as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through other comprehensive income.

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A summary of the pension benefit as of the years ended December 31, 2014 and 2013 is set forth in the below tables (in thousands):

	2014	2013
Change in benefit obligation		
Benefit obligation at beginning of year	\$ 9,018	\$
Oxford assumed benefit obligations		9,045
Service cost	70	144
Interest cost	335	203
Gain on reduction of pension liability	(2,208)	
Actuarial loss	1,616	(350)
Benefits paid	(2,031)	(24)
Benefit obligation at end of period	\$ 6,800	\$ 9,018
 Change in plan assets		
Fair value of plan assets at beginning of year	\$ 7,521	\$
Oxford assumed plan assets		6,523
Actual return on plan assets	(11)	1,012
Employer contributions		10
Benefit paid	(2,031)	(24)
Fair value of plan assets at December 31, 2014	\$ 5,479	\$ 7,521

The funding level of the qualified pension plan is in compliance with standards set by applicable law or regulation. As shown in the table below, the current pension plan is underfunded. All defined benefit pension obligations, regardless of the funding status of the plan, are fully supported by the financial strength of the Company.

	2014	2013
	(in thousands)	
Assets in excess of (less than) benefit obligation at December 31,		
Vested amount	\$ (6,800)	\$ (7,039)
Additional benefits required		(1,979)
Projected benefit obligation	(6,800)	(9,018)
Funded amount	5,479	7,521
Unfunded amount	\$ (1,321)	\$ (1,497)
 Other amounts recognized in other comprehensive loss during the year ended December 31,		
Assets in excess of (less than) benefit obligation at end of period	\$ (1,321)	\$ (1,497)
Amounts recorded in the consolidated balance sheet consist of:		
Accrued benefit liability	(1,321)	(1,497)

Total recorded	\$ (1,321)	\$ (1,497)
Beginning amount recorded in other accumulated comprehensive income	\$ 1,168	\$
Amounts recorded in accumulated other comprehensive loss consist of:		
Pension obligation adjustment, net of tax	(1,716)	1,168
Total recorded in accumulated other comprehensive income	\$ (548)	\$ 1,168

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The long-term expected rate of return on funded assets shown below is established for each benefit plan by developing a forward-looking, long-term return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. A single, long-term rate of return is then calculated as the weighted average of the target asset allocation percentages and the long-term return assumption for each asset class. The discount rate is determined by constructing a portfolio of high-quality, noncallable bonds with cash flows that match estimated outflows for benefit payments.

	For the Year Ended December 31,	
	2014	2013
Weighted average assumptions to determine benefit obligation		
Discount rate	3.75%	4.75%
Expected rate of return	6.00%	6.00%
Rate of compensation increase	4.00%	4.00%
Inflation	3.00%	3.00%
Components of net periodic benefit cost (in thousands)		
Service cost	\$ 70	\$ 144
Interest cost	335	203
Expected return on plan assets	(448)	(195)
Amortization of transition obligation	70	140
Amortization of net (gain) loss	29	
Net period benefit cost	\$ 56	\$ 292

The following benefit payments are expected to be paid over the next ten years (in thousands):

2015	\$ 8
2016	9
2017	25
2018	68
2019	106
2020-2024	1,798

The Company's investment strategy for benefit plan assets reflects a long-term view, a careful assessment of the risks inherent in various asset classes and broad diversification to reduce the risk of the portfolio. The Company, along with its investment manager, determines the investment policies and strategies for the plan assets to determine the allocations to the various asset classes based on the results of the studies targeted percentages. The following tables below set forth the breakout of asset categories as of December 31, 2014 and 2013 (in thousands):

	December 31,	
	2014	2013
Plan assets by category		
Equity securities	\$	\$ 7,398

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Debt securities	5,392	117
Cash	87	6
Total Assets	\$ 5,479	\$ 7,521
Plan assets by category		
Equity securities	N/A	98.3%
Debt securities	98.4%	1.6%
Cash	1.6%	0.1%
Total Assets	100%	100%

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The following tables set forth by level, within the fair value hierarchy, the fair value of pension assets as of December 31, 2014 and 2013 (in thousands):

	December 31, 2014			Total
	Level 1	Level 2	Level 3	
Pension assets	\$ 5,206	273		\$ 5,479

	December 31, 2013			Total
	Level 1	Level 2	Level 3	
Pension assets	\$ 7,404	117		\$ 7,521

The fair value measurement levels are accounting terms that refer to different methods of valuing assets. The terms do not represent the relative risk or credit quality of an investment.

Note 10 Equity*Initial Public Offering*

On June 25, 2014, the Company completed its initial public offering (IPO) of 30,300,000 shares of our common stock, which included 21,500,000 shares sold by the Company and 8,800,000 shares sold by certain stockholders. The net proceeds from the IPO were approximately \$544.7 million, after deducting underwriting discounts and commissions and the offering expenses payable by the Company of approximately \$35.8 million. The Company used a portion of the net proceeds received from the IPO to repay the then-outstanding borrowings under Eclipse I s revolving credit facility and to fund the Company s capital expenditure plan.

Incentive Units

Eclipse Holdings has a total of 1,000 Class C-1 units and 1,000 Class C-2 units authorized to be issued to employees (Incentive Units). The Series C-1 and C-2 Incentive Units are non-voting with respect to partnership matters, and the holder thereof will begin to participate in distributions from Eclipse Holdings after distributions have been made to the holders of the Series A-1 and A-2 units that satisfy a specified hurdle rate and return on investment factor, with the level of participation in distributions adjusting upwards as distributions to the holders of the Series A-1 and A-2 units satisfy additional specified hurdle rates and return on investment factors.

Total compensation cost related to the Incentive Units was less than \$0.1 million for each of the years ended December 31, 2014, 2013 and 2012. As of December 31, 2014, there was \$0.7 million of total unrecognized compensation cost related to Incentive Units, which is expected to be recognized over a weighted-average period of 6.34 years.

The determination of the fair value of the awards noted above uses significant Level 3 assumptions in the fair value hierarchy including an estimate of the timing of an Exit Event, forfeitures, the risk free rate and a volatility estimate tied to the Company s public peer group.

Restricted Stock Issued to Directors

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The Company has 16,000,000 shares of common stock authorized to be issued in accordance with its 2014 Long-Term Incentive Plan. On October 7, 2014, the Company issued 31,115 restricted shares of common stock, par value \$0.01, to seven non-employee members of its Board of Directors. As of December 31, 2014 the Company recognized expense of approximately \$0.1 million and expects to recognize \$0.3 million during 2015 until the restricted shares become fully vested on June 25, 2015.

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Table of Contents*Private Placement of Common Stock*

On December 27, 2014, the Company entered into a Securities Purchase Agreement with the EnCap Funds, the Management Funds and the other stockholders pursuant to which was agreed to issue and sell to such purchasers an aggregate of 62,500,000 shares of common stock at a price of \$7.04 per share pursuant to the exemptions from registration provided in Rule 506 of Regulation D promulgated under Section 4(2) of the Securities Act, such transaction referred to herein as the private placement.

On January 28, 2015, the Company closed the private placement and received net proceeds from the issuance of the shares to the purchasers of approximately \$434 million (after deducting placement agent commissions and estimated expenses), which the Company intends to use to fund its capital expenditure plan and for general corporate purposes. Upon the closing of the private placement, the Company amended and restated the existing registration rights agreement that was entered into upon the closing of the IPO to give the stockholders certain registration rights with respect to the stock purchased in the private placement.

Note 11 Earnings (Loss) Per Share*Earnings (loss) Per Share*

Basic earnings (loss) per share (EPS) is computed by dividing net income (loss) by the weighted-average number of shares of common stock outstanding during the period. Diluted EPS takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with any stock awards that have been granted to directors and employees. In accordance with FASB ASC Topic 260, awards of non-vested shares shall be considered to be outstanding as of the grant date for purposes of computing diluted EPS even though their exercise is contingent upon vesting. The following is a calculation of the basic and diluted weighted-average number of shares of common stock outstanding and EPS for the years ended:

(in thousands, except per share data)	Year Ended December 31,		
	2014	2013	2012
Loss (numerator):			
Net loss	(183,176)	(43,541)	(8,759)
Weighted-average shares (denominator):			
Weighted-average number of shares of common stock basic and diluted	144,369	75,261	13,880
Loss per share:			
Basic and diluted	\$ (1.27)	\$ (0.58)	\$ (0.63)

Note 12 Related Party Transactions

In December 2010, Eclipse Operating was formed by members of the Company's management team for purposes of operating Eclipse I. The Company's Chairman, President and Chief Executive Officer, Executive Vice President, Secretary and General Counsel and Executive Vice President and Chief Operating Officer each owned 33% of the membership units of Eclipse Operating. Eclipse Operating provide administrative and management services to Eclipse I under the terms of an Administrative Services Agreement. In connection with the Corporate Reorganization, Eclipse I acquired of all the outstanding equity interests of Eclipse Operating for \$0.1 million, which is the amount of the aggregate capital contributions made to Eclipse Operating by its members. As a result, Eclipse Operating became a wholly owned subsidiary of Eclipse I.

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Under the terms of the Administrative Services Agreement, Eclipse I paid Eclipse Operating a monthly management fee equal to the sum of all general and administrative expenditures incurred in the management and administration of Eclipse I s operations. These costs included salaries, wages and benefits, rent, insurance, and other expenses and costs required to operate Eclipse I. These expenses were billed in arrears at the actual cost to Eclipse Operating. During the period from January 1, 2014 to June 23, 2014 the Company s management fee to

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Eclipse Operating was \$15.6 million. The Company's management fee to Eclipse Operating was \$14.7 million, and \$4.2 million for the years ending December 31, 2013 and 2012, respectively. These expenses are classified within *Operating expenses - General and administrative* in the consolidated statements of operations.

As of December 31, 2014, the Company has recorded an accrued liability of \$972,000 related to a final distribution of the assets of Eclipse Operating. This amount will be distributed equally among the three former shareholders during 2015 and is reflected as a reduction of initial gain recorded on the acquisition of Eclipse Operating, which is classified within *Other income* in the Consolidated Statements of Operations.

During the year ended December 31, 2014 the Company incurred approximately \$0.2 million related to flight charter services provided by BWH Air, LLC and BWH Air II, LLC, which are owned by the Company's Chairman, President and Chief Executive Officer. The fees are paid in accordance with a standard service contract that does not obligate the Company to any minimum terms.

Note 13 Commitments and Contingencies

(a) Legal Matters

Prior to the Oxford Acquisition, Oxford commenced a lawsuit on October 24, 2011 in the Common Pleas Court of Belmont County, Ohio against Mr. Barry West, a lessor under an Oxford oil and gas lease, to enforce its rights to access and drill a well pursuant to the lease during its initial 5-year primary term. The lessor counterclaimed, alleging, among other things, that the challenged Oxford lease constituted a lease in perpetuity and, accordingly, should be deemed void and contrary to public policy in the State of Ohio. On October 4, 2013, the Belmont County trial court granted a motion for summary judgment in favor of the lessor and ruled that the lease is a *no term* perpetual lease and, as such, is void as a matter of Ohio law.

The Company has appealed the trial court's decision in the *West* case to the Ohio Court of Appeals for the Seventh Appellate District, arguing, among other things, that the Belmont County trial court erred in finding that the lease is a *no term* perpetual lease, by ruling that perpetual leases are void as a matter of Ohio law and by invalidating such leases. The Company cannot predict the outcome of this lawsuit or the amount of time and expense that will be required to resolve the lawsuit.

In addition, many of the Company's other oil and gas leases in Ohio contain provisions identical or similar to those found in the challenged Oxford lease. As of March 6, 2015, we are a party to one other lawsuit that makes allegations similar to those made by the lessor in the *West* lawsuit. This lawsuit, together with the *West* case, affect approximately 157 gross (157 net) leasehold acres and were capitalized on our balance sheet as of December 31, 2014 at \$0.6 million.

The Company has undertaken efforts to amend the other leases acquired within the Utica Core Area in the Oxford Acquisition to address the issues raised by the trial court's ruling in the *West* case. These efforts have resulted in modifications to leases covering approximately 34,256 net acres out of the approximately 46,549 net acres. The Company's offer may require modification to address the issues raised by the trial court while the Company's appeal is pending; however, the Company cannot predict whether the Company will be able to obtain modifications of the leases covering the remaining 12,293 net acres to effectively resolve issues related to the West trial court's ruling or the amount of time and expense that will be required to amend these leases.

In light of the foregoing, if the appeals court affirms the trial court ruling in the *West* case, and if other courts in Ohio adopt a similar interpretation of the provisions in other oil and gas leases the Company acquired in the Oxford

Acquisition, other lessors may challenge the validity of such leases and those challenged leases may be declared void. Consequently, this could result in a loss of the mineral rights and an impairment of the related assets which could have a material adverse impact on the Company's financial statements. These costs could potentially be impaired if it was determined that the West lawsuit leases are invalid. Other than this potential impairment, the Company is not able to estimate the range of other potential losses related to this matter.

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On September 26, 2014, the Ohio Court of Appeals for the Seventh Appellate District, the same appellate court that will decide the Company's appeal in the *West* case, issued its decision in the case of Clyde Hupp et al. v. Beck Energy Corporation, an appeal of a Monroe County trial court decision upon which the trial court in *West* based its decision. The appellate court held that while Ohio law disfavors perpetual leases, courts in Ohio have not found them to be per se illegal or void from their inception. The appellate court further held that the trial court misinterpreted both the pertinent lease provisions and Ohio law on the subject and erred in concluding that the Beck Energy lease is a no-term, perpetual lease that is void ab initio as against public policy. On November 7, 2014, the plaintiff landowners filed an appeal of the appellate court's decision with the Supreme Court of Ohio, which was accepted by the Supreme Court of Ohio on January 28, 2015. On March 2, 2015, the Ohio Court of Appeals for the Seventh Appellate District stayed all proceedings in the Company's appeal in the *West* case pending a decision by the Supreme Court of Ohio in the *Hupp v. Beck Energy* appeal.

The Company believes that there are strong grounds for appeal of the *West* decision, and therefore, the Company intends to pursue all available appellate rights, and to vigorously defend against the claims in this lawsuit. Based on the merits of the Company's appeal and the favorable holdings in the *Hupp v. Beck Energy* appellate decision described above, the Company believes that it is not probable that trial court's decision in *West* will be upheld in the appeal or that the Company will incur a material loss in the lawsuit. The Company has not recorded an accrual for the potential losses attributable to this lawsuit.

Other Matters

From time to time, the Company may be a party to legal proceedings arising in the ordinary course of business. Management does not believe that a material loss is probable as a result of such proceedings.

(b) Environmental Matters

The Company is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

(c) Leases

The development of the Company's oil and natural gas properties under their related leases will require a significant amount of capital. The timing of those expenditures will be determined by the lease provisions, the term of the lease and other factors associated with unproved leasehold acreage. To the extent that the Company is not the operator of oil and natural gas properties that it owns an interest in, the timing, and to some degree the amount, of capital expenditures will be controlled by the operator of such properties.

The Company leases office space under operating leases that expire between the years 2015 to 2025. Rent expense related to the lease agreements for the years-ended December 31, 2014 and 2013 was \$0.3 million and \$0.1 million. No rent expense was incurred for the year ended December 31, 2012.

The following is a schedule by year, of the future minimum lease payments required under the lease agreements as of December 31, 2014 (in thousands).

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2015	\$ 773
2016	749
2017	753
2018	756
2019	756
Thereafter	3,494
Total minimum lease payments	\$ 7,281

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Table of Contents**Note 14 Income Tax**

For 2014, the Company's annual effective tax rate is an expense of approximately 64.47%, inclusive of the Change in Tax Status charge (see Note 3 *Summary of Significant Accounting Policies*) and the gain on acquisition of Eclipse Operating (see Note 4 *Acquisitions*). The Company incurred a tax loss in the current year (due principally to the ability to expense certain intangible drilling and development costs under current law) and thus, no current federal income taxes will be due. This tax loss results in a net operating loss carryforward at year-end; however, no valuation allowance has been recorded as management believes that there is sufficient future taxable income to fully utilize all tax attributes. This future taxable income arises from reversing temporary differences due to the excess of the book carrying value of oil and gas properties over their corresponding tax bases. Management is not relying on other sources of taxable income in concluding that no valuation allowance is needed.

	Year Ended December 31, 2014(1)	
	(in thousands)	
Current		
Federal	\$	
State		132
Total current		132
Deferred		
Federal		71,838
State		(171)
Total deferred		71,667
Total income tax expense	\$	71,799

(1) For the 2013 and 2012 comparable periods, the calculation is not applicable as the Company was not a taxable entity until June 25, 2014.

The Company's income tax expense differs from the amount derived by applying the statutory federal rate to pretax loss principally due the effect of the following items (in thousands):

	Year Ended December 31, 2014(1)	
Loss before income taxes	\$	(111,377)
Statutory rate		35%
Income tax benefit computed at statutory rate		(38,982)

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Reconciling items:		
Non-deductible pre-IPO loss		13,264
State income taxes		(39)
Other, net		71
Change in tax status		97,609
Gain on acquisition of Eclipse Operating		(124)
Income tax expense	\$	71,799

- (1) For the 2013 and 2012 comparable periods, the calculation is not applicable as the Company was not a taxable entity until June 25, 2014.

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Deferred income taxes primarily represent the net tax effect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. The components of our deferred taxes are detailed in the table below (in thousands):

	Year Ended	
	December 31, 2014(1)	
Current deferred tax asset:		
State effect of current deferreds	\$	104
Other, net		2,140
Net current deferred tax asset	\$	2,244
Non-current deferred tax asset:		
Federal tax loss carryforwards	\$	127,497
State effect of non-current deferreds		21
Other, net		668
Net non-current deferred tax asset	\$	128,186
Current deferred tax liability:		
Derivative instruments and other	\$	6,966
Other, net		524
Net current deferred tax liability	\$	7,490
Non-current deferred tax liability:		
Oil and gas properties and equipment	\$	194,900
Other, net		
Net non-current deferred tax liability	\$	194,900
Reflected in the accompanying balance sheet as:		
Net deferred tax liability current	\$	5,246
Net deferred tax liability noncurrent	\$	66,714

(1) For the 2013 and 2012 comparable periods, the calculation is not applicable as the Company was not a taxable entity until June 25, 2014.

The Company has a U.S. federal tax loss carryforward (NOL) of approximately \$364 million as of December 31, 2014. This NOL was generated in tax year 2014 and will generally be available for use through tax year 2034. The Company expects to file initial corporate tax returns for federal and various state jurisdictions for the tax year ended December 31, 2014 prior to the extended due dates. Upon filing, the tax year ended December 31, 2014 will remain open to examination under the applicable statute of limitations in the U.S. and other jurisdictions in which the Company and its subsidiaries file income tax returns. However, the statute of limitations for examination of NOLs and other similar attribute carryforwards does not commence until the year the attribute is utilized. In some instances, state

statutes of limitations are longer than those under U.S. federal tax law. Tax returns for predecessor entities prior to 2011 are generally not subject to examination.

As of December 31, 2014, the Company has not recorded a reserve for any uncertain tax positions. No federal income tax payments are expected in the upcoming four quarterly reporting periods.

On September 13, 2013, the US Treasury and IRS issued final Tangible Property Regulations (TPR) under IRC Section 162 and IRC Section 263(a) for tax years beginning on or after January 1, 2014. The Company analyzed the TPR and concluded there is minimal impact for the tax year ended December 31,2014. The Company will continue to monitor the impact of any future changes to the TPR on the Company prospectively.

Table of Contents**Note 15 Subsequent Events**

Management has evaluated subsequent events and believes that there are no events that would have a material impact on the aforementioned financial statements and related disclosures, except for the amendment to the Revolving Credit Facility in January 2015 and redetermination of the borrowing base in March 2015 (refer Note 8 *Debt*) and the Private Placement of Common Stock that closed in January 2015 (refer Note 10 *Equity*).

Note 16 Quarterly Financial Information (unaudited)

Summarized quarterly financial data for the years ended December 31, 2014 and 2013 are presented in the following table. In the following table, the sum of basic and diluted Earnings (Loss) per common share for the four quarters may differ from the annual amounts due to the required method of computing weighted average number of shares in the respective periods. Additionally, due to the effect of rounding, the sum of the individual quarterly earnings (loss) per share amounts may not equal the calculated year earnings (loss) per share amount (in thousands, except per share data).

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 13, 2014				
Total operating revenues	24,788	26,955	35,702	50,371
Total operating expenses	25,992	34,166	60,806	101,026
Operating loss	(1,204)	(7,211)	(25,104)	(50,655)
Net loss	(18,451)	(112,648)	(19,054)	(33,023)
Loss per common share:				
Basic and diluted	\$ (0.15)	\$ (0.84)	\$ (0.12)	\$ (0.21)

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Year ended December 13, 2013				
Total operating revenues	288	570	4,510	7,567
Total operating expenses	2,052	5,766	10,055	17,753
Operating loss	(1,764)	(5,196)	(5,545)	(10,186)
Net loss	(1,759)	(5,740)	(16,484)	(19,558)
Loss per common share:				
Basic and diluted.	\$ (0.10)	\$ (0.10)	\$ (0.14)	\$ (0.16)

Note 17 Supplemental Oil and Natural Gas Information (unaudited)**(a) Capitalized Costs**

A summary of the Company's capitalized costs are contained in the table below (in thousands):

December 31,
2014 2013

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Oil and natural gas properties:		
Proved properties	\$ 1,044,469	\$ 926,812
Unproved properties	802,112	97,528
Total oil and natural gas properties	1,846,581	1,024,340
Less accumulated depreciation, depletion and amortization	(131,857)	(8,596)
Net oil and natural gas properties	\$ 1,714,724	\$ 1,015,744

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Table of Contents***(b) Costs Incurred in Oil and Natural Gas Property Acquisition and Development Activities***

A summary of the Company's cost incurred in oil and natural gas property acquisition and development activities is set forth below (in thousands):

	2014	December 31, 2013	2012
Acquisition costs:			
Proved properties	\$	\$ 40,914	\$ 2,498
Unproved properties	134,156	621,039	158,131
Development cost	714,796	258,825	16,344
Exploration cost	21,186	3,022	3,899
Total acquisition, development and exploration costs	\$ 870,138	\$ 923,800	\$ 180,872

(c) Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2014 and December 31, 2013, which have been prepared and presented under SEC rules. These rules require companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12-month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2014 and December 31, 2013 was based on an unweighted average 12-month average West Texas Intermediate posted price per Bbl for oil and NGLs and a Henry Hub spot natural gas price per MMBtu for natural gas.

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. This requirement may limit the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Appalachian Basin of Ohio. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves within the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are all located in the United States, within the State of Ohio. All of the estimates of the proved reserves at December 31, 2014 and December 31, 2013, were prepared by Netherland, Sewell & Associates, Inc. (NSAI), independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are

expected to change as additional information becomes available in the future.

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The following table provides a roll-forward of the total proved reserves for the year ended December 31, 2014, 2013, and 2012 as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Natural Gas (MMCF)	Natural Gas Liquids (MBbl)	Oil (MBbl)	TOTAL (MMcfe)
End of year, December 31, 2011				
Extensions and discoveries	2,963.8	177.0	390.5	6,368.9
Production	(7.7)		(4.5)	(34.7)
End of year, December 31, 2012	2,956.1	177.0	386.0	6,334.2
Revisions	2,645.0	52.1	(163.2)	1,978.4
Extensions and discoveries	41,215.5	1,710.6	1,323.3	59,419.0
Acquisition of reserves	6,646.6		958.5	12,397.6
Production	(1,118.8)	(1.3)	(87.2)	(1,650.2)
End of year, December 31, 2013	52,344.4	1,938.4	2,417.4	78,478.6
Revisions	(12,091.2)	(739.7)	(462.6)	(19,305.3)
Extensions and discoveries	235,816.9	10,216.3	4,337.5	323,140.1
Production	(19,760.2)	(536.0)	(594.9)	(26,545.5)
End of year, December 31, 2014	256,309.9	10,879.0	5,697.4	355,767.9
Proved developed reserves:				
December 31, 2012	1,289.6	64.6	174.5	2,724.0
December 31, 2013	27,880.3	1,056.2	1,708.1	44,466.6
December 31, 2014	132,959.5	6,758.6	3,880.9	196,796.4
Proved undeveloped reserves:				
December 31, 2012	1,666.6	112.4	211.5	3,610.1
December 31, 2013	24,464.1	882.2	709.2	34,012.0
December 31, 2014	123,350.4	4,120.4	1,816.4	158,971.5

Extensions and discoveries of 323,140.1 MMCFE and 59,419 MMCFE during the years ended December 31, 2014 and December 31, 2013, respectively, resulted primarily from the drilling of new wells during each year and from new proved undeveloped locations added during each year.

Table of Contents**(d) Standardized Measure of Discounted Future Net Cash Flows**

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties, and consideration of expected future economic and operating conditions. The estimates of future cash flows and future production and development costs as of December 31, 2014 and 2013 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%. The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows at December 31, 2014 and 2013 (in thousands):

	December 31,		
	2014	2013	2012
Future cash inflows (total revenues)	\$ 1,870,319	\$ 479,527	\$ 50,614
Future production costs (severance and ad valorem taxes plus LOE)	(728,041)	(116,161)	(6,448)
Future development costs (capital costs)	(350,187)	(76,511)	(8,015)
Future income tax expense	(277,500)		
Future net cash flows	514,591	286,855	36,151
10% annual discount for estimated timing of cash flows	(183,934)	(131,560)	(14,257)
Standardized measure of Discounted Future Net Cash Flow	\$ 330,657	\$ 155,295	\$ 21,894

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of the Company's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

(e) Changes in the Standardized Measure of Discounted Future Net Cash Flows

A summary of the changes in the standardized measure of discounted future net cash flows are contained in the table below (in thousands):

	December 31,		
	2014	2013	2012
Standardized Measure, beginning of the year	\$ 155,295	\$ 21,894	\$
Net change in prices and production costs	(52,642)	(5,354)	354
Net change in future development costs	(2,122)	(1,148)	
Sales, Less production costs	(104,099)	(10,281)	(354)
Extensions	491,067	106,720	21,894

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Acquisitions		28,984	
Revisions of previous quantity estimates	(38,201)	8,354	
Previously estimated development costs incurred	16,807		
Accretion of discount	15,529	2,189	
Net change in taxes	(178,732)		
Changes in timing and other	27,755	3,937	
Period Balance	\$ 330,657	\$ 155,295	\$ 21,894

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