Eclipse Resources Corp
Form 10-Q
August 14, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 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	**46-4812998**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
2121 Old Gatesburg Rd, Suite 110 State College, PA	**16803**
(Address of principal executive offices)	**(Zip code)**

(814) 308-9754

(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ¨ Yes x 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 x 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.

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x (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 x No

Number of shares of the registrant s common stock outstanding at August 14, 2014: 160,000,000 shares

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ECLIPSE RESOURCES CORPORATION

QUARTERLY REPORT ON FORM 10-Q

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Cautionary Statement Regarding Forward-Looking Statements

This Quarterly Report on Form 10-Q (the Quarterly 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 Quarterly 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 Quarterly Report, the words will, would, could, believe, anticipate intend, estimate, expect, project and similar expressions are intended to identify forward-looking statements, althou 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 under the heading Risk Factors in our final prospectus dated June 19, 2014 and filed with the Securities Exchange Commission pursuant to Rule 424(b) of the Securities Act on June 23, 2014 (the IPO Prospectus), and in Item 1A. Risk Factors of this Quarterly Report.

Forward-looking statements may include statements about:

- 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;
- general economic conditions;
- 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 Quarterly 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 under the heading Item 1A. Risk Factors in our Final Prospectus of Form S-1 and in Item 1A. Risk Factors of this Quarterly Report.

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 Quarterly 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 Quarterly 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

Quarterly Report.

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Commonly Used Defined Terms

As used in this Quarterly 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 Re Corporation and its consolidated subsidiaries, including Eclipse Resources I, L.P., Eclipse Resources-Ohio, LLC, and Eclipse Resources Operating, LLC;

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

Eclipse Holdings refers to Eclipse Resources Holdings, L.P.;

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 L.P.;

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;

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

Bbls/d. Bbls per day.

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. One Boe 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.

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 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.

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 ofrock 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.

MBbl. One thousand barrels.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet.

Mcf/d. One Mcfper 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 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.

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.

SEC. The United States Securities and Exchange Commission

Spot market price. The cash market price without reduction for expected quality, transportation and demand adjustments.

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.

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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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

Introduction to the Condensed Consolidated Financial Statements

The following unaudited condensed consolidated financial statements of Eclipse Resources Corporation for the period from January 1, 2014 through June 24, 2014, as contained within the three and six months ended June 30, 2014; the three and six months ended June 30, 2013; and as of December 31, 2013, pertain to the historical financial statements and results of operations of Eclipse I, our accounting predecessor.

The unaudited condensed consolidated financial statements have been prepared based on the fact that Eclipse Resources Corporation is treated as a corporation for federal income tax purposes. The unaudited condensed consolidated financial statements should be read in conjunction with the notes accompanying such unaudited condensed consolidated financial statements as well as Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations, each included elsewhere in this Quarterly Report.

Please see *Commonly Used Defined Terms* of this Quarterly Report for definitions of some of the terms used in the notes to the Company s condensed consolidated financial statements. The unaudited condensed consolidated financial statements as of and for the three and six months ended June 30, 2014 reflect the following transactions:

Corporate Reorganization

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, which we refer to collectively as the 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 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 GP, LLC, to us by Eclipse Holdings in exchange for 138,500,000 shares of our common stock.

As a result of the Corporate Reorganization, we became a majority controlled direct subsidiary of Eclipse Holdings, and Eclipse I became our direct subsidiary.

Initial Public Offering

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

The gross proceeds of our IPO, based on the public offering price of $27.00 per share, were approximately $818.1 million, which resulted in net proceeds to us of approximately $545.4 million after deducting expenses and underwriting discounts and commissions of approximately $35.1 million. We did not receive any proceeds from the sale of the shares by the certain selling stockholders. The net proceeds we received from our IPO were used to repay all of the then outstanding borrowings under our revolving credit facility, and we expect to use the remaining net proceeds to fund a portion of our capital expenditure plan.

Upon completion of the IPO and the Corporate Reorganization, we had 160,000,000 shares of common stock outstanding.

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ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands, except per share data)

(unaudited)

	June 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 493,420	$ 109,509
Accounts receivable	41,634	8,678
Other current assets	2,080	594
Deferred tax asset	1,543	
Total current assets	538,677	118,781
PROPERTY AND EQUIPMENT, AT COST		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,090,589	926,812
Proved properties	278,152	97,528
Accumulated depreciation, depletion and amortization	(30,422)	(8,596)
Total oil and natural gas properties, net	1,338,319	1,015,744
Other property and equipment, net	6,999	2,340
Total property and equipment, net	1,345,318	1,018,084
OTHER NONCURRENT ASSETS		
Debt issuance costs, net of $1,624 and $759 of amortization, respectively	6,807	6,570
Other assets	75	88
Total other noncurrent assets	6,882	6,658
TOTAL ASSETS	$ 1,890,877	$ 1,143,523
LIABILITIES AND STOCKHOLDERS EQUITY AND PARTNERS CAPITAL		
CURRENT LIABILITIES		
Accounts payable	$ 93,100	$ 29,368
Accrued capital expenditures	31,330	19,200
Accrued liabilities	17,870	4,940
Accrued interest payable	23,243	20,294
Accrued liabilities related party		1,951
Total current liabilities	165,543	75,753

NONCURRENT LIABILITIES		
Debt, net of unamortized discount of $9,638 and $10,822, respectively	412,823	389,247
Pension liability	631	1,497
Asset retirement obligations	9,534	9,055
Other liabilities	179	
Deferred tax liabilities	96,377	
Total noncurrent liabilities	519,544	399,799
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY AND PARTNERS CAPITAL		
Partners capital		666,803
Preferred stock, 50,000 shares authorized, No shares issued and outstanding at June 30, 2014. No shares authorized, issued, or outstanding at December 31, 2013		
Common stock, $0.01 par value per share, 1,000,000 shares authorized, 160,000 shares issued and outstanding at June 30, 2014. No shares authorized, issued, or outstanding at December 31, 2013	1,600	
Additional paid-in capital	1,391,523	
Accumulated deficit	(187,268)	
Accumulated other comprehensive income (loss)	(65)	1,168
Total stockholders equity and partners capital	1,205,790	667,971
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY AND PARTNERS CAPITAL	$ 1,890,877	$ 1,143,523

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

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ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)

(unaudited)

	For the Three Months Ended June 30, 2014	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
REVENUES				
Oil and natural gas sales	$ 26,955	$ 570	$ 51,743	$ 858
Total revenues	26,955	570	51,743	858
OPERATING EXPENSES				
Lease operating	2,643	125	4,434	130
Transportation, gathering and compression	2,949		3,853	
Production and ad valorem taxes	702	2	1,055	6
Depreciation, depletion and amortization	9,957	495	21,984	983
Exploration	9,295	48	13,840	120
General and administrative	8,429	4,979	16,823	6,462
Accretion of asset retirement obligations	191	117	377	117
Gain on reduction of pension liability			(2,208)	
Total operating expenses	34,166	5,766	60,158	7,818
OPERATING LOSS	(7,211)	(5,196)	(8,415)	(6,960)
OTHER INCOME (EXPENSE)				
Loss on derivative instruments	(863)		(4,474)	
Interest expense, net	(11,618)	(544)	(25,254)	(539)
Other income	1,585		1,585	
Total other expense, net	(10,896)	(544)	(28,143)	(539)
LOSS BEFORE INCOME TAXES	(18,107)	(5,740)	(36,558)	(7,499)
INCOME TAX EXPENSE	94,541		94,541	
NET LOSS	$ (112,648)	$ (5,740)	$ (131,099)	$ (7,499)
NET LOSS PER COMMON SHARE				
Basic and diluted	$ (0.84)		$ (1.02)	
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING				
Basic and diluted	134,309		128,480	

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

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ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE LOSS

(in thousands)

(unaudited)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
NET LOSS	$ (112,648)	$ (5,740)	$ (131,099)	$ (7,499)
Other comprehensive loss:				
Pension obligation adjustment	(371)		(1,233)	
TOTAL COMPREHENSIVE LOSS	$ (113,019)	$ (5,740)	$ (132,332)	$ (7,499)

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

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ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENT OF STOCKHOLDERS EQUITY AND PARTNERS CAPITAL

(in thousands)

(unaudited)

	For the Six Months Ended June 30, 2014					
	Partners Capital	Common Stock ($0.01 Par Value per Share)	Additional Paid-in-Capital	Accumulated Deficit	Accumulated Other Comprehensive Income (Loss)	Total
BALANCE AT DECEMBER 31, 2013	$ 666,803	$	$	$	$ 1,168	$ 667,971
Net loss				(131,099)		(131,099)
Capital contributions	124,667					124,667
Incentive unit compensation	56					56
Pension obligation adjustment					(1,233)	(1,233)
IPO proceeds		1,600	548,425			550,025
IPO offering costs			(4,597)			(4,597)
Effect of corporate reorganization	(791,526)		847,695	(56,169)		
BALANCE AT JUNE 30, 2014	$	$ 1,600	$ 1,391,523	$ (187,268)	$ (65)	$ 1,205,790

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

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ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

(unaudited)

	For the Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (131,099)	$ (7,499)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation, depletion and amortization	21,984	983
Exploration expense	13,840	120
Pension benefit costs	111	
Incentive unit compensation	56	
Accretion of asset retirement obligations	377	117
Gain on reduction of pension liability	(2,208)	
Loss on derivative instruments	4,474	
Net cash payments on settled derivatives	(2,231)	
Net cash paid for option premium	(141)	
Gain on acquisition of business	(1,585)	
Deferred income taxes	94,541	
Interest not paid in cash	2,166	500
Amortization of deferred financing costs	885	
Amortization of debt discount	1,115	33
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	(31,795)	(2,923)
Other assets	(883)	(848)
Accounts payable and accrued liabilities	26,294	87
Accrued liabilities related parties	(1,951)	
Net cash used in operating activities	(6,050)	(9,430)
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures on oil and natural gas properties	(278,250)	(113,232)
Additions to other property and equipment	(1,454)	
Acquisition of business, net of cash acquired	754	(651,847)
Proceeds from the sale of assets		8,497
Net cash used in investing activities	(278,950)	(756,582)
CASH FLOWS FROM FINANCING ACTIVITIES		
Debt issuance costs	(1,122)	(6,810)

Capital contributions		124,667		583,046
Proceeds from issuance of common stock, net of underwriting fees		550,025		
Initial public offering costs		(4,597)		
Proceeds from issuance of long-term debt				288,000
Repayments of long-term debt		(62)		
(Payments on) proceeds from revolving credit facility, net				
Net cash provided by financing activities		668,911		864,236
Net increase in cash and cash equivalents		383,911		98,224
Cash and cash equivalents at beginning of period		109,509		27,057
Cash and cash equivalents at end of period	$	493,420	$	125,281
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid for interest	$	448	$	
Cash paid for income taxes	$		$	
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:				
Asset retirement obligations incurred, including changes in estimate	$	102	$	
Additions of other property through debt financing	$	507	$	
Additions to oil and natural gas properties change in accounts payable, accrued liabilities and accrued capital expenditure	$	79,890	$	5,199
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 CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

FOR THE SIX MONTHS ENDED JUNE 30, 2014 and 2013

(Unaudited)

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 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 membership 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 of the IPO, based on the public offering price of $27.00 per share, were approximately $818.1 million, which resulted in net proceeds of approximately $545.4 million after deducting expenses and underwriting discounts and commissions of approximately $35.1 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 unaudited condensed consolidated financial statements of Eclipse Resources Corporation for the period from January 1, 2014 through June 23, 2014, as contained within the three and six months ended June 30, 2014; the three and six months ended June 30, 2013; and as of December 31, 2013, pertain to the historical financial statements and results of operations of Eclipse Resources I, LP., our accounting predecessor.

The accompanying condensed consolidated financial statements, which are unaudited except the balance sheet at December 31, 2013 which is derived from audited financial statements, are presented in accordance with the requirements of and accounting principles generally accepted in the United States (U.S. GAAP) for interim reporting. They do not include all disclosures normally made and contained in annual financial statements. In management s opinion, all adjustments necessary for a fair presentation of the Company s financial position, results of operations and cash flows for the periods disclosed have been made. These interim condensed consolidated financial statements should be read in conjunction with the audited financial statements and notes thereto presented in the Company s financial statements for the year ended December 31, 2013.

Operating results for interim periods may not necessarily be indicative of the results of operations for the full year ending December 31, 2014 or any other future periods.

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 condensed consolidated financial statements are the following:

- estimates of proved reserves of oil and natural gas, which affect the calculations of depletion, depreciation 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 June 30, 2014 or December 31, 2013.

The Company accrues unbilled 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 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 $23.6 million and $4.1 million of unbilled revenues at June 30, 2014 and December 31, 2013, respectively, which were included in accounts receivable within the Company s condensed 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 facilities 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. These costs are reviewed regularly and a final determination for unproved leasehold costs is made within one year of the costs being incurred. 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 condensed consolidated statements of operations. Upon the sale of an individual well, the proceeds are credited to accumulated depreciation and depletion within the Company s condensed 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 condensed 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.

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

	June 30, 2014	December 31, 2013
Oil and natural gas properties:		
Unproved	$ 1,090,589	$ 926,812
Proved	278,152	97,528
Gross oil and natural gas properties	1,368,741	1,024,340
Less accumulated depreciation, depletion and amortization	(30,422)	(8,596)
Oil and natural gas properties, net	1,338,319	1,015,744
Other property and equipment	7,877	2,392
Less accumulated depreciation	(878)	(52)
Other property and equipment, net	6,999	2,340
Property and equipment, net	$ 1,345,318	$ 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. Exploratory drilling costs are evaluated and a determination of classification is made within one year from the completion of drilling. As of June 30, 2014 and December 31, 2013, there were no costs capitalized in connection with exploratory wells in progress.

Other Property and Equipment

Other property and equipment include land, buildings, 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 June 30, 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. There was one customer that accounted for 10% or more of the total natural gas, NGLs and oil sales for the three and six months ended June 30, 2014. There were two customers that accounted for 10% or more of the total natural gas, NGLs and oil sales for the three and six months ended June 30, 2013. 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 three months ended June 30,		For the six months ended June 30,	
	2014	2013	2014	2013
Purchaser				
Antero Resources Corporation	73%	51%	63%	67%
Devco Oil Company	5%	15%	6%	10%
Total	78%	66%	69%	77%

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

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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.

(f) Concentration of Credit Risk

The following table summarizes concentration of receivables, net of allowances, by product or service as of June 30, 2014 and December 31, 2013 (in thousands):

	June 30, 2014	December 31, 2013
Receivables by product or service:		
Sale of oil and natural gas and related products and services	$ 23,241	$ 4,092
Joint interest owners	18,383	4,586
Miscellaneous other	10	
Total	$ 41,634	$ 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 liability position of $1.2 million at June 30, 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 June 30, 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 $0.6 and $1.5 million at June 30, 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 $0.0 and $2.2 million for the three and six months ended June 30, 2014, respectively. No such gain was recorded for the three and six months ended June 30, 2013, as the Company did not have a pension benefit plan prior to the acquisition of The Oxford Oil Company (Oxford) (see Note 4 - *Acquisitions*).

(h) Depreciation, Depletion and Amortization (DD&A)

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 unit 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 for the three months ended June 30, 2014 and 2013 totaled approximately $10.0 million and $0.5 million, respectively, and for the six months ended June 30, 2014 and 2013 totaled approximately $22.0 million and $1.0 million, respectively.

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 three months ended June 30, 2014 and 2013 totaled approximately $0.13 million and $0.0, respectively; and for the six months ended June 30, 2014 and 2013 totaled approximately $0.2 million and $0.0, respectively. This amount is included in DD&A expense in the condensed 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.

The review of the Company s oil and gas properties is done on a unit level basis 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. 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 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 $3.7 million to impairment of unproved oil and gas properties related to lease expirations for the three and six months ended June 30, 2014, which is included in exploration expense in the condensed consolidated statements of operations. No such impairments were recorded for the three and six months ended June 30, 2013.

Proved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. There were no impairments of proved oil and gas properties recorded by the Company for the three or six months ended June 30, 2014 or 2013.

(j) Income Taxes

Upon the closing of the Corporate Reorganization, the Company owned 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 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 $95 million was recorded as income tax expense at the date of the completion of the Corporate Reorganization.

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.

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 date 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.

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(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 condensed 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 condensed 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 condensed 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.

(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 8.96% for the six months ended June 30, 2014.

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.

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

	Six Months Ended June 30, 2014	
Asset retirement obligations, beginning of period	$	9,055
Additional liabilities incurred		102
Accretion		377
Asset retirement obligations, end of period	$	9,534

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 - 2018. 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.

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(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 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 2014-06, *Technical Corrections and Improvements Related to Glossary Terms* . These amendments relate to glossary terms and cover a wide range of Topics in the Codification. These amendments are presented in four sections: (1) Deletion of Master Glossary Terms arising because of terms that were carried forward from source literature to the Codification but were not utilized in the Codification; (2) Addition of Master Glossary Term Links arising from Master Glossary terms whose links did not carry forward to the Codification; (3) Duplicate Master Glossary Terms arising from Master Glossary terms that appear multiple times in the Master Glossary with similar, but not identical, definitions; and (4) Other Technical Corrections Related to Glossary Terms arising from miscellaneous changes to update Master Glossary terms. These requirements were effective upon issuance. The adoption of this ASU did not impact the Company s financial position, results of operations or liquidity.

The FASB issued ASU 2014-11, *Transfers and Servicing (Topic 860) - Repurchase-to-Maturity Transactions, Repurchase Financings, and Disclosures* . These amendments align the accounting for repurchase-to-maturity transactions and repurchase agreements executed as a repurchase financing with the accounting for other typical repurchase agreements. Going forward, these transactions would all be accounted for as secured borrowings. The guidance eliminates sale accounting for repurchase-to-maturity transactions and supersedes the guidance under which a transfer of a financial asset and a contemporaneous repurchase financing could be accounted for on a combined basis as a forward agreement, which has resulted in outcomes referred to as off-balance-sheet accounting. ASU 2014-11 also brings U.S. GAAP into greater alignment with IFRS for repurchase-to-maturity transactions. The amendments in the ASU require a new disclosure for transactions economically similar to repurchase agreements in which the transferor retains substantially all of the exposure to the economic return on the transferred financial assets throughout the term of the transaction. The amendments in the ASU also require expanded disclosures about the nature of collateral pledged in repurchase agreements and similar transactions accounted for as secured borrowings. These requirements are effective for annual reporting periods beginning after December 15, 2014, 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.

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.

Note 4 Acquisitions

Eclipse Resources Operating, LLC Acquisition

On June 24, 2014, prior to the closing of the IPO, the Company acquired all of the outstanding membership interests of Eclipse Operating for total consideration of $127,500. 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 $1.6 million related to the purchase, which is included in other income on the condensed consolidated statements of operations.

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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.

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 party to various lawsuits, primarily related to the validity of certain oil and gas leases (see Note 12 *Commitments and Contingencies*).

Pro Forma Financial Information (unaudited)

The following unaudited pro forma financial information represents the combined results for the Company and Oxford for the three and six months ended June 30, 2013 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 $3.7

million and $7.0 million for the three month and six months ended June 30, 2013. The pro forma information includes the effects of adjustments for amortization of financing costs of $0.2 million and $0.4 million for three month and six months ended June 30, 2013, respectively. The pro forma information includes the effects of the amortization of debt discount of $0.3 million and $0.6 million for three month and six months ended June 30, 2013, respectively. The pro forma information includes the effects of the incremental interest expense on acquisition financing of $5.2 million and $10.3 million for three month and six months ended June 30, 2013, 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 Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2013
Oil and natural gas sales	$ 4,710	$ 8,849
Net loss	$ (14,731)	$ (22,333)

Note 5 Derivative Financial 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 and put options spreads to manage its exposure to natural gas price fluctuations. 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, the Company

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receives 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, the Company pays 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 the Company 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. The prices contained in these derivative contracts are based on NYMEX Henry Hub prices. Below is summary of the Company s derivative instrument positions, as of June 30, 2014, for future production periods:

Description	**Volume (MMBtu/d)**	**Production Period**		**Weighted Average Swap Price ($/MMBtu)**	
Natural Gas Swaps:					
	20,000	July 2014	December 2014	$	4.175
	20,000	January 2015	December 2015		4.090

Description:	**Volume (MMBtu/d)**	**Production Period**		**Weighted Average Strike Price ($/MMBtu)**	
Natural Gas Put Spread:					
Purchased put	20,000	July 2014	December 2014	$	4.50
Sold put	20,000	July 2014	December 2014	$	4.00

All of the Company s derivative instruments are used for risk management purposes and none are held for trading or speculative purposes.

Fair values and gains(losses)

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 condensed consolidated balance sheets (in thousands):

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 June 30, 2014							
Assets							
Commodity derivatives - current	$	637	$	(637)	$		
Commodity derivatives - noncurrent		4		(4)			
Total assets	$	641	$	(641)	$		
Liabilities							

Commodity derivatives - current	$	(1,695)	$	637	$	(1,058)	Accrued liabilities
Commodity derivatives - noncurrent		(183)		4		(179)	Other liabilities
Total liabilities	$	(1,878)	$	641	$	(1,237)	

(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 for the periods presented (in thousands):

		Amount of Gain (Loss) Recognized in Income			
		Three months ended June 30,		**Six months ended June 30,**	
Derivatives not designated as hedging instruments under ASC 815	**Location of Gain(Loss) Recognized in Income**	**2014**	**2013**	**2014**	**2013**
Commodity derivatives	Loss on derivative Instruments	$ (863)	$	$ (4,474)	$

Note 6 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 condensed 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 June 30, 2014: (in thousands)				
Commodity derivative instruments	$	$ (1,237)	$	$ (1,237)
Total	$	$ (1,237)	$	$ (1,237)

The Company did not have any assets or liabilities that were measured at fair value on a recurring basis as of December 31, 2013.

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.

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.

The estimated fair values of the Company s financial instruments closely approximate the carrying amounts due, except for long-term debt. (see Note 7 *Debt*)

Note 7 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 1, 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 three and six months ended June 30, 2014, the Company amortized $0.8 million and $1.1 million, respectively, 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. At the Company s option, for the subsequent four semi-annual interest payments thereafter, interest may be 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. Interest paid by issuing PIK securities accrues at 13%, interest paid by cash accrues at 12%. The Company elected to settle its accrued interest payable of $22.5 million with PIK securities on January 15, 2014. As of June 30, 2014, the Company had accrued additional interest in the amount of $23.2 million, which was paid in cash on July 15, 2014. The Company capitalized interest expense totaling $1.8 million and $2.6 million for the three and six months ended June 30, 2014, respectively.

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 June 30, 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 June 30, 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 June 30, 2014 was $510.8 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 June 30, 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 $25 million, the Company had available capacity on the Revolving Credit Facility of $75 million at June 30, 2014.

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 June 30, 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 8 Benefit Plans

The Company maintains a defined benefit pension plan covering 34 of its employees who were formerly employees of Oxford, 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 Company s plans are funded in conformity with the funding requirements of ASC 715 as of June 30, 2014. Effective March 31, 2014, benefit accruals in the plan were frozen resulting in a gain on reduction of pension liability of $0.0 and $2.2 million for the three and six months ended June 30, 2014, respectively.

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. A summary of the pension benefit as of the six months ended June 30, 2014 is set forth in the below table (in thousands):

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Change in benefit obligation	
Benefit obligation at beginning of year	$ 9,018
Service cost	70
Interest cost	192
Gain on reduction of pension liability	(2,137)
Actuarial loss	1,010
Benefits paid	(1,029)
Benefit obligation at end of period	$ 7,124
Change in plan assets	
Fair value of plan assets at beginning of year	$ 7,521
Actual return on plan assets	1
Benefit paid	(1,029)
Fair value of plan assets at June 30, 2014	$ 6,493

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.

Assets in excess of (less than) benefit obligation at June 30, 2014	
Vested amount	$ (7,124)
Additional benefits required	
Projected benefit obligation	(7,124)
Funded amount	6,493
Unfunded amount	$ (631)
Other amounts recognized in other comprehensive loss during the six months ended June 30, 2014	
Assets in excess of (less than) benefit obligation at end of period	$ (631)
Amounts recorded in the condensed consolidated balance sheet consist of:	
Accrued benefit liability	(631)
Total recorded	$ (631)
Beginning amount recorded in accumulated other comprehensive income (loss)	$ 1,168
Amounts recorded in accumulated other comprehensive income (loss) consist of:	

Pension obligation adjustment		(1,233)
Total recorded in accumulated other comprehensive income (loss)	$	(65)

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.

Weighted average assumptions to determine benefit obligation at June 30, 2014	
Discount rate	4.00%
Expected rate of return	6.00%
Rate of compensation increase	
Inflation	3.00%

Components of net periodic benefit cost (benefit) for the three and six months ended June 30, 2014		**Three Months Ended June 30, 2014**		**Six Months Ended June 30, 2014**
Service cost	$		$	70
Interest cost		85		192
Expected return on plan assets		(112)		(224)
Amortization of transition obligation				70
Amortization of net (gain) loss		11		3
Net periodic benefit cost(benefit)	$	(16)	$	111

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The following benefit payments are expected to be paid over the next ten years (in thousands):

2014	$ 1,031
2015	2
2016	39
2017	91
2018	133
2019 2023	$ 1,756

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 June 30, 2014 (in thousands):

Plan assets by category	
Equity securities	
Debt securities	6,425
Cash	68
Total assets	$ 6,493

Plan assets by category	
Equity securities	
Debt securities	99%
Cash	1%
Total assets	100%

The following tables set forth by level, within the fair value hierarchy, the fair value of pension assets as of June 30, 2014 (in thousands):

	June 30, 2014			
	Level 1	**Level 2**	**Level 3**	**Total**
Pension assets	$ 6,171	322		$ 6,493

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 9 Equity

Corporate Reorganization

On June 25, 2014, the Company completed the 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 resulting in net proceeds to the Company of approximately $545.4 million (See Note 1 *Organization and Nature of Operations*).

Prior to the Corporate Reorganization, Eclipse I issued Series A-1, A-2, B-1, C-1 and C-2 limited partnership units. The Series C-1 and C-2 units were non-voting and were issued to certain key employees of Eclipse I and Eclipse Operating. As a result of the Corporate Reorganization, the limited partners of Eclipse I immediately prior to the Corporate Reorganization became the limited partners of Eclipse Holdings and received Series A-1, A-2, B-1, C-1 and C-2 units of Eclipse Holdings. The Company s business continues to be conducted through Eclipse I and Eclipse Operating as our wholly owned subsidiaries.

Holders of Series A-1, A-2, B-1, C-1 and C-2 units of Eclipse Holdings are entitled to distributions from the assets of Eclipse Holdings (through either an in-kind distribution of shares of the common stock of Eclipse Resources Corporation or in cash generated by the sale of such common stock) in accordance with the terms of the limited partnership agreement of Eclipse Holdings, but are not entitled to distributions or other payments from the Company. The Series A-1, A-2, B-1, C-1 and C-2 units of Eclipse Holdings are not convertible into indebtedness or securities of the Company, and the Company is not obligated to purchase the Series A-1, A-2, B-1, C-1 and C-2 units of Eclipse Holdings.

The following tables set forth the Series A-1, A-2 and B-1 units issued and outstanding as of June 30, 2014 and 2013 (in thousands):

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	June 30, 2014	
	Units Authorized	**Units Issued**
Units		
A-1	3,896	3,896
A-2	6,171	6,171
B-1	110	110
Total Units	10,177	10,177

	June 30, 2013	
	Units Authorized	**Units Issued**
Units		
A-1	3,896	3,896
A-2	4,930	4,930
B-1	104	104
Total Units	8,930	8,930

During the six months ended June 30, 2014, the Company issued 1.24 million A-2 units and 0.006 million B units for $125 million.

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.

The Incentive Units were issued with one of two vesting scenarios, either (i) in one-third increments or (ii) at the earlier of (a) an Exit Event or (b) seven years. An Exit Event is generally defined in the limited partnership agreement of Eclipse Holdings as the sale of Eclipse Resources Corporation, to one or more persons, none of whom is a partner of Eclipse Holdings or an affiliate of a partner, in one transaction or a series of related transactions, whether structured as (i) a sale or transfer of all or substantially all of the equity interests of Eclipse Resources Corporation (including by way of merger, consolidation, share exchange, or similar transaction), (ii) the sale or other transfer of all or substantially all of the assets of Eclipse Resources Corporation promptly or (iii) a combination of any of the foregoing. The Corporate Reorganization and the IPO did not constitute an Exit Event and did not result in accelerated vesting of any of the Incentive Units. In the event an employee terminates his or her employment with the Company prior to vesting, the non-vested Incentive Units will be forfeited by the holder. Compensation expense for these awards is calculated based on the fair value at the date of grant and is recognized over the requisite service period.

A summary of the Incentive Unit awards as of June 30, 2014 and 2013, along with the changes during the periods then ended, is as follows:

	2014			2013		
		Weighted Average Grant Date Fair Value			Weighted Average Grant Date Fair Value	
	C-1 Units	per unit		C-1 Units	per unit	
Nonvested at December 31,	560	$	131	794	$	48
Granted				40		1,033
Vested	(338)		58	(111)		36
Forfeited	(25)		851			
Nonvested at June 30,	197	$	305	723	$	83

	2014			2013		
		Weighted Average Grant Date			Weighted Average Grant Date	
	C-2 Units	Fair Value		C-2 Units	Fair Value	
Nonvested at December 31,	182	$	2,501		$	
Granted	32		11,958	150		197
Vested	(25)		3,553			
Forfeited	(13)		1,174			
Nonvested at June 30,	176	$	4,525	150	$	164

Total compensation expense related to the Incentive Units was $0.06 million as of June 30, 2014. As of June 30, 2014, there was $1.0 million of total unrecognized compensation cost related to Incentive Units, which is expected to be recognized over a weighted-average period of 6.45 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.

Note 10 Earnings (Loss) Per Share and Pro Forma Earnings (Loss) Per Share

Earnings 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 six months ended June 30, 2014.

(in thousands, except per share data)	Three Months Ended June 30, 2014		Six Months Ended June 30, 2014	
Loss (numerator):				
Net loss	$	(112,648)	$	(131,099)
Weighted-average shares (denominator):				
Weighted-average number of shares of common stock basic and diluted		134,309		128,480
Loss per share:				
Basic and diluted	$	(0.84)	$	(1.02)

Pro Forma EPS

The Company s pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued in the IPO were outstanding for the entire period. A reconciliation of the components of pro forma basic and diluted earnings per common share is presented in the table below:

	Three Months Ended June 30, 2014		Six Months Ended June 30, 2014	
Numerator:				
Loss before taxes, as reported	$	(18,107)	$	(36,558)
Pro forma provision for income tax benefit		6,337		12,795

Pro forma net income	$	(11,770)	$	(23,763)
Denominator:				
Weighted-average number of common shares outstanding basic and diluted		160,000		160,000
Net income per share:				
Basic and diluted	$	(0.07)	$	(0.15)

Note 11 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 provides 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 $127,500, 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.

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.

The Company considered the requirements of ASC Topic 810 Consolidation and determined Eclipse Operating to be a variable interest entity. The variable interest primarily relates to the Administrative Services Agreement between the two entities and the management fee charged for the services provided by Eclipse Operating to Eclipse I equal to the actual expenditures incurred for such operations. Eclipse I concluded it was not the primary beneficiary of the variable interest entity. During the period from January 1, 2014 to June 23, 2014 and the six months ended June 30, 2013, the Company s management fee to Eclipse Operating was $15.6 million and $4.5 million, respectively, classified within *Operating expenses General and administrative* in the condensed consolidated statements of operations.

Note 12 Commitments and Contingencies

(a) Legal Matters

West Matter

Prior to the Oxford Acquisition, Oxford commenced a lawsuit on October 24, 2011 in the Common Pleas Court of Belmont County, Ohio against a lessor to enforce its rights to access and drill a well on the lease during the initial 5-year primary term of the lease. 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

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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 Belmont County trial court s decision 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. Following the ruling of the Belmont County trial court, three other lessors filed lawsuits, or amended existing complaints in pending lawsuits, that remain outstanding against the Company to make allegations similar to those made by the lessor in the Belmont County case discussed above. These three lawsuits, together with the Belmont County case discussed above, affect approximately 419 gross (419 net) leasehold acres and were capitalized on our balance sheet as of June 30, 2014 at $4.0 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 Belmont County trial court s ruling. These efforts have resulted in modifications to leases covering approximately 28,192 net acres out of the approximately 46,549 net acres. The Company 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 18,357 net acres to effectively resolve issues related to the Belmont County 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, 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 were invalid. Other than this potential impairment, the Company is not able to estimate the range of other potential losses related to this matter.

The Company believes that there are strong grounds for appeal, 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 appeal, the Company believes that it is not probable that trial court s decision 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 - 2018. Rent expense related to the lease agreements for the three months ended June 30, 2014 and 2013 was $0.06 million and $0.00 million, respectively; and for the six months ended June 30, 2014 and 2013 was $0.08 million and $0.00 million, respectively.

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Note 13 Income Tax

For 2014, the Company s annual estimated effective tax rate is expected to be 35%, exclusive of the Change in Tax Status charge (see Note 3 *Summary of Significant Accounting Policies*) and a discrete item related to the gain on acquisition of Eclipse Operating (see Note 4 *Acquisitions*). The Company expects to incur a tax loss in fiscal year 2014 (due principally to the ability to expense certain intangible drilling and development costs under current law) and thus, no current income taxes are anticipated to be paid. This tax loss is expected to result in a Net Operating Loss carryforward at year-end; however, no valuation allowance has been (or is expected to be) 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.

As of June 30, 2014, the Company has not recorded a reserve for any uncertain tax positions.

Note 14 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.

Item 2: Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with Management s Discussion and Analysis of Financial Condition and Results of Operations contained in our IPO Prospectus, and our consolidated financial statements and related notes appearing elsewhere in this Quarterly 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. See Cautionary Statement Regarding Forward-Looking Statements. Also, see the risk factors and other cautionary statements described under the heading Risk Factors included in the IPO Prospectus and in Item IA of this Quarterly 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 Item 1. Financial Statements - Introduction to the Condensed Consolidated Financial Statements (the IPO Transactions). 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 24, 2014, as contained within the three and six months ended June 30, 2014, and for the three and six months ended June 30, 2013, 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 99,333 of our net acres are located in the Utica Shale fairway, which we refer to as the Utica Core Area, and approximately 26,962 of these net acres are in 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 an 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 Corporation (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 June 30, 2014, we, or our operating partners, had commenced drilling 115 gross (44 net) wells within the Utica Core Area and Our Marcellus Project Area, of which 27 gross (18 net) were drilling, 17 gross (5 net) were awaiting completion, 16 gross (4 net) were in the process of being completed, 16 gross (5 net) were awaiting midstream and 39 gross (12 net) had been turned to sales.

As of June 30, 2014, we were operating 4 horizontal rigs and 1 top-hole rig in the Utica Core Area. We frequently utilize top-hole rigs ahead of our horizontal rigs to drill the vertical portion of our wells in order to maximize the drilling efficiency of our larger horizontal drilling rigs and reduce overall costs. As of June 30, 2014, after deducting wells that have been drilled or are in progress, we had identified 3,674 gross (956 net) remaining horizontal drilling locations across our acreage, comprised of 2,717 gross (711 net) locations within the Utica Core Area and 957 gross (245 net) locations within Our Marcellus Project Area.

As of June 30, 2014, we were producing approximately 185.5 gross (50.4 net) MMcfe per day comprised of approximately 69% natural gas, 16% NGLs and 15% oil.

Total proved reserves as of June 30, 2014 were 186.4 Bcfe, or 31.1 MMBoe, and our proved developed reserves totaled 93.1 Bcfe, or 15.5 MMBoe. Our pretax PV 10 as of June 30, 2014 totaled $337.9 million using SEC pricing assumption of $3.88 per Mcf of natural gas, $95.27 per Bbl of oil and condensate and $40.11 per Bbl of NGLs. Additionally, our estimated proved reserves were approximately 76% natural gas, 14% NGLs and 10% oil, as of June 30, 2014. Our reserve estimates at June 30, 2014 were prepared by Eclipse internal reserve engineers and have not been reviewed or audited by our independent reserve engineers.

Pre-tax PV10 value is a non-GAAP financial measure as defined by the SEC. The Company believes that the presentation of pre-tax PV10 value is relevant and useful to the Company s investors because it presents the discounted future net cash flows attributable to the Company s reserves prior to taking into account future corporate income taxes and the Company s current tax structure. We further believe investors and creditors use pre-tax PV10 value as a basis for comparison of the relative size and value of the Company s reserves as compared with other companies. With respect to PV10 calculated as of an interim date, it is not practical to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

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, which are extracted from our natural gas during processing, and oil. During the six months ended June 30, 2014, our revenues were comprised of approximately 46.4%, 13.4% and 40.2% 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 and put option spreads. 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. 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. Historically, we have not hedged basis differentials associated with our natural gas production, although we may elect to do so in the future. 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 3. *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.

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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 will 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. We estimate these direct incremental G&A expenses will be approximately $3 million per year. This estimate does not include non-cash compensation expenses, which we expect to incur in the future. These direct incremental G&A expenses are not included in our historical results of operations.

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 three and six months ended June 30, 2014, and for the three and six months ended June 30, 2013, 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 the 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. Eclipse I, our predecessor, 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. Accordingly, our historical financial data may not present an accurate indication of what our actuals 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.

Income Taxes. Income tax expense was approximately $95 million during the three and six months ended June 30, 2014. We were not a tax paying entity during the corresponding periods of fiscal year 2013 and therefore, no income tax expense was recorded by us during such periods. Income tax expense for the three and six months ended June 30, 2014 is made up of two elements: (i) the Change in Tax Status charge, and (ii) income tax expense (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 bases as of the closing date of the Corporate Reorganization. As a result, during the three and six months ended June 30, 2014, we recorded a tax charge of approximately $94.5 million.

During the three and six months ended June 30, 2014, we also recorded $0.1 million of income tax expense related to continuing operations. This represents an application of our estimated annual effective tax rate (including state income taxes) for 2014 to our income subject to corporate tax earned from the Corporate Reorganization date through June 30, 2014. Please see Note 13. *Income Taxes* located in the Notes to the Condensed Consolidated Financial Statements included in Item 1 of Part I of this Quarterly Report on Form 10-Q.

Increased Horizontal Drilling Activity. We began horizontal, unconventional drilling operations in 2012, and through June 30, 2014, we, or our operating partners, had commenced drilling 115 gross (44 net) wells. We expect to drill or participate in 185 gross (76 net) horizontal wells in 2014. 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 June 30, 2014, we had outstanding indebtedness 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.

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 we refer to as our Revolving Credit Facility. Our Revolving Credit Facility matures on January 15, 2018 and includes customary affirmative and negative covenants. The initial borrowing base under our Revolving Credit Facility was $50.0 million, and as of May 1, 2014, our borrowing base was increased to $100.0 million. The Company had no outstanding borrowings under the Revolving Credit Facility as of June 30, 2014.

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 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.

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 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 expect to 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 will 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; 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; and exploration expenses. Adjusted EBITDAX is not a measure of net income as determined by generally accepted accounting principles in the United States (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.

Overview of the Three Months Ended June 30, 2014 Results

Operationally, our performance during the three months ended June 30, 2014 reflects continued development of our Utica Core Area and Our Marcellus Project Area acreage, continuing the delineation process across these two acreage positions. During the three months ended June 30, 2014, we achieved the following financial and operating results:

- completed our IPO of 30,300,000 shares of $0.01 par value common stock, with gross proceeds of our IPO of approximately $818.1 million, which resulted in net proceeds to us of approximately $545.4 million;

- increased our net production by 10% from the period ended March 31, 2014 to 41.9 MMcfe per day;

- increased total net proved reserves by 70%, or 76.8 Bcfe, to 186.4 Bcfe;

- commenced drilling 24 gross (16 net) operated Utica Shale wells and completed 6 gross (4.0 net) operated Utica Shale wells of which 3 gross (2.5 net) wells were placed into sales during the quarter;

- participated in 16 gross (2.5 net) non-operated Utica Shale wells and completed 8 gross (0.8 net) non-operated Utica Shale wells of which 12 gross (2.6 net) wells were placed into sales during the quarter;

increased our acreage in the Utica Core Area to 99,333 net acres and increased Our Marcellus Project Area acreage to 26,962 net acres;

net loss was $(112.7) million for the three months ended June 30, 2014 compared to $(5.7) million for the three months ended June 30, 2013; and

Adjusted EBITDAX was $11.3 million for the three months ended June 30, 2014 compared to $(4.5) million for the three months ended June 30, 2013.

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Overview of the Six Months Ended June 30, 2014 Results

Operationally, our performance during the six months ended June 30, 2014 reflects continued development of our Utica Core Area and Our Marcellus Project Area acreage continuing the delineation process across these two acreage positions. During the six months ended June 30, 2014, we achieved the following financial and operating results:

- completed our IPO of 30,300,000 shares of common stock, resulting in gross proceeds of approximately $818.1 million, and net proceeds to us of approximately $545.4 million;

- increased total net proved reserves by 139%, or 107.9 Bcfe, compared to December 31, 2013;

- commenced drilling 32 gross (21.7 net) operated Utica Shale wells and completed 6 gross (4.2 net) operated Utica Shale wells of which 3 gross (2.5 net) wells were placed into sales during the year;

- participated in 26 gross (3.7 net) non-operated Utica Shale wells and completed 8 gross (0.8 net) non-operated Utica Shale wells of which 28 gross (6.0 net) wells were placed into sales during the year;

- contracted for firm gathering, cryogenic processing and fractionation capacity for our operated Utica Shale liquids rich natural gas production;

- during 2014 the Company entered into long-term firm transportation contracts with pipelines to sell a portion of its expected natural gas production beginning in 2015. The contracts range in term and extend through 2025 to 2031. The Company s annual commitment is approximately $46 million and is payable per MMbtu of natural gas transported on the pipelines;

- net loss was $(131.1) million for the six months ended June 30, 2014 compared to $(7.5) million for the six months ended June 30, 2013; and

- Adjusted EBITDAX was $23.3 million for the six months ended June 30, 2014 compared to $(5.7) million for the six months ended June 30, 2013.

Acquisitions

During the six months ended June 30, 2014, we continue selective acreage leasing to add to our acreage positions primarily in the Utica Core Area and Our Marcellus Project Area.

Divestitures

During the six months ended June 30, 2014, there were no divestitures by us.

Fiscal 2014 Outlook

For fiscal 2014, our board approved a $696.3 million capital budget comprised of $577.3 million for drilling and completion, $115.8 million for land related expenditures and leasehold acquisitions and $3.2 million for other purposes. Our capital budget excludes acquisitions, other than routine leasehold acquisitions. We expect to continue to fund our capital expenditures in fiscal 2014 with cash generated by operations, borrowings under our Revolving Credit Facility, net proceeds received from the issuance of our Senior Unsecured Notes, capital contributions received prior to the date of the IPO and a portion of the net proceeds from the IPO. 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 cause us to reduce our drilling activity resulting 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.

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 three months ended June 30, 2014 and 2013 and the six months ended June 30, 2014 and 2013.

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	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
NYMEX Henry Hub High ($/MMBtu)	$ 4.83	$ 4.41	$ 6.15	$ 4.41
NYMEX Henry Hub Low ($/MMBtu)	4.28	3.57	4.01	3.12
Average NYMEX Henry Hub ($/MMBtu)	4.58	4.02	4.65	3.76
NYMEX WTI High ($/Bbl)	$ 107.26	$ 98.44	$ 107.26	$ 98.44
NYMEX WTI Low ($/Bbl)	99.42	86.68	91.66	86.68
Average NYMEX WTI ($/Bbl)	102.99	94.17	100.84	94.26

Results of Operations

Three Months Ended June 30, 2014 Compared to Three Months Ended June 30, 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 three months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		
	2014	2013	Change
Revenues (in thousands):			
Natural gas sales	$ 10,066	$ 124	$ 9,942
NGLs sales	6,329		6,329
Oil sales	10,560	446	10,114
Total revenues	$ 26,955	$ 570	$ 26,385

Our production grew approximately 3,755 MMcfe for the three months ended June 30, 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 three months ended June 30, 2014 and 2013 is set forth in the following table:

	Three Months Ended June 30,		
	2014	2013	Change
Production:			
Natural gas (MMcf)	2,458.8	31.0	2,427.8
NGLs (Mbbls)	113.1		113.1
Oil (Mbbls)	113.2	5.1	108.1
Total (MMcfe)	3,816.6	61.8	3,754.8
Average daily production volume:			

Natural gas (Mcf/d)	27,020	340	26,680
NGLs (Bbls/d)	1,243		1,243
Oil (Bbls/d)	1,244	56	1,188
Total (Mcfe/d)	41,941	679	41,262

Our average realized price received during the three months ended June 30, 2014 was $7.06 per Mcfe compared to $9.23 per Mcfe in the three months ended June 30, 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 three months ended June 30, 2014, as compared to the three months ended June 30, 2013. Average realized prices (wellhead) do not include any third party transportation costs, which are reported in transportation, gathering and compression expense on our condensed consolidated statements of operations. Average realized price calculations, excluding the effects of hedges, for the three months ended June 30, 2014 and 2013 are shown in the following table.

	Three Months Ended June 30,		
	2014	**2013**	**Change**
Volume weighted average realized prices:			
Natural gas ($/Mcf)(1)	$ 4.09	$ 4.02	$ 0.07
NGLs ($/Bbl)	55.95		55.95
Oil ($/Bbl)	93.30	86.77	6.53

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	Three Months Ended June 30, 2014	2013	Change
Average price ($/Mcfe)	7.06	9.23	(2.17)
Differential to Average NYMEX Henry Hub(2)	(0.46)	0.03	(0.49)
Differential to Average NYMEX WTI(2)	(10.04)	(5.79)	(4.25)

(1) Including the effects of commodity hedging, the average effective price for the three months ended June 30, 2014 would have been $3.74 per Mcf of gas. The total volume of gas associated with these hedges for the three months ended June 30, 2014 represented approximately 74% of our total sales volumes. There were no commodity derivatives in place for the three months ended June 30, 2013.
(2) Differential compares actual NYMEX Henry Hub and WTI prices to our actual volume-weighted average realized prices for gas and oil, respectively.

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 three months ended June 30, 2014 and 2013.

	Three Months Ended June 30, 2014	2013	Change
Operating expenses (in thousands):			
Lease operating	$ 2,643	$ 125	$ 2,518
Transportation, gathering and compression	2,949		2,949
Production and ad valorem taxes	702	2	700
Depreciation, depletion and amortization	9,957	495	9,462
General and administrative	8,429	4,979	3,450
Operating expenses per Mcfe:			
Lease operating	$ 0.69	$ 2.02	$ (1.33)
Transportation, gathering and compression	0.77		0.77
Production and ad valorem taxes	0.18	0.03	0.15
Depletion, depreciation and amortization	2.61	8.01	(5.40)
General and administrative	2.21	80.60	(78.39)

Lease operating expense was $2.6 million in the three months ended June 30, 2014 compared to $0.1 million in the three months ended June 30, 2013. The increase of $2.5 million is attributable to higher production during the three months ended June 30, 2014, as compared to the three months ended June 30, 2013. Lease operating expenses include normally recurring expenses to operate and produce our wells and non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties. We incurred $0.5 million in workover costs, associated primarily with legacy conventional wells, in the three months ended June 30, 2014 compared to $0 in three months ended June 30, 2013

Transportation, gathering and compression expense was $2.9 million during the three months ended June 30, 2014 compared to $0 in the three months ended June 30, 2013. These third party costs were higher in the three months ended June 30, 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 $0.7 million in the three months ended June 30, 2014 compared to less than $0.002 million in the three months ended June 30, 2013. Production and ad valorem taxes increased from the three months ended June 30, 2013 to the three months ended June 30, 2014 due to an increase in production volumes subject to production or ad valorem taxes.

Depreciation, depletion and amortization was approximately $10.0 million in the three months ended June 30, 2014 compared to $0.5 million in the three months ended June 30, 2013. The increase in the three months ended June 30, 2014 when compared to the three months ended June 30, 2013 is due to the increase in production during 2014. On a per Mcfe basis, DD&A decreased to $2.61 in the three months ended June 30, 2014 from $8.01 in the three months ended June 30, 2013, which was predominantly driven by a lower depletion rate. The decrease in depletion rate during the three months ended June 30, 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 $8.4 million for the three months ended June 30, 2014 compared to $5.0 million for the three months ended June 30, 2013. The increase of $3.4 million during the three months ended June 30, 2014 when compared to three months ended June 30, 2013 is primarily due to higher salaries and benefits related to the hiring of a significant number of new employees during the three months ended June 30, 2014. We recorded $0.03 million and $0 of non-cash incentive unit compensation charges for the three months ended June 30, 2014 and 2013, respectively. We expect that our personnel costs will continue to increase

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as we invest in our technical teams and other staffing to support the expansion of our drilling program in the Utica Core Area and Our Marcellus Project Area.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include exploration expense and accretion of asset retirement obligation expense. The following table details our other operating expenses for three months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		
	2014	2013	Change
Other Operating Expenses (in thousands):			
Exploration	$ 9,295	$ 48	$ 9,247
Accretion of asset retirement obligations	191	117	74

Exploration expenses increased to $9.3 million in the three months ended June 30, 2014 compared to $0.05 million in the three months ended June 30, 2013 due to higher impairment of unproved properties related to lease expirations, seismic costs, and delay rentals due to acreage increases and lease modifications. The following table details our exploration-related expenses for the three months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		
	2014	2013	Change
Exploration Expenses (in thousands):			
Seismic	$ 290	$ 6	$ 284
Delay rentals	5,237	40	5,197
Dry hole	102	2	100
Impairment of unproved properties	3,666		3,666
	$ 9,295	$ 48	$ 9,247

Impairment of unproved properties was $3.7 million for the three months ended June 30, 2014 compared to $0.0 million for the three months ended June 30, 2013. 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 of asset retirement obligations was $0.2 million in the three months ended June 30, 2014, compared to $0.1 million in the three months ended June 30, 2013. Accretion expense relates to the increase in the asset retirement obligations associated with new wells drilled during the three months ended June 30, 2014 and existing wells acquired in the Oxford Acquisition in June 2013.

Other Income (Expense)

Loss on derivative instruments was $0.9 million for the three months ended June 30, 2014. There was no gain or loss on derivatives in the three months ended June 30, 2013 as the Company did not have derivative instruments in place during this period. The $0.9 million loss on derivative instruments includes approximately $1 million of net cash payments on settled derivatives.

Interest expense, net was $11.6 million for the three months ended June 30, 2014. We incurred $0.5 million in interest expense in the three months ended June 30, 2013. The increase in interest expense during the three months ended June 30, 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 related offering expenses as well as the $60 million drawn on our Revolving Credit Facility during 2014.

Other income was $1.6 million for the three months ended June 30, 2014 representing the gain on acquisition of Eclipse Operating.

Income tax expense was $94.5 million for the three months ended June 30, 2014 primarily related to a charge to record the initial impact of the change in our tax status as a result of the Corporate Reorganization.

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Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 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 six months ended June 30, 2014 and 2013.

	Six Months Ended June 30,		
	2014	**2013**	**Change**
Revenues (in thousands):			
Natural gas sales	$ 24,025	$ 177	$ 23,848
NGLs sales	6,904		6,904
Oil sales	20,814	681	20,133
Total revenues	$ 51,743	$ 858	$ 50,885

Our production for the six months ended June 30, 2014 grew by approximately 7,172 MMcfe compared to the six months ended June 30, 2013 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 each of the six months ended June 30, 2014 and 2013 is set forth in the following table:

	Six Months Ended June 30,		
	2014	**2013**	**Change**
Production:			
Natural gas (MMcf)	5,205.5	45.2	5,160.3
NGLs (Mbbls)	122.4		122.4
Oil (Mbbls)	221.0	8.1	212.9
Total (MMcfe)	7,265.9	93.9	7,172.0
Average daily production volume:			
Natural gas (Mcf/d)	28,760	250	28,510
NGLs (Bbls/d)	676		676
Oil (Bbls/d)	1,221	45	1,176
Total (Mcfe/d)	40,143	519	39,624

Our average realized price received during the six months ended June 30, 2014 was $7.12 per Mcfe compared to $9.13 per Mcfe in the six months ended June 30, 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 six months ended June 30, 2014, as compared to the six months ended June 30, 2013. Average realized prices (wellhead) do not include any third party transportation costs, which are reported in transportation, gathering and compression expense on our condensed consolidated statements of operations. Average realized price calculations for the six months ended June 30, 2014 and 2013 are shown in the following table.

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013	Change
Volume weighted average realized prices:			
Natural gas ($/Mcf) [1]	$ 4.62	$ 3.91	$ 0.71
NGLs ($/Bbl)	56.41		56.41
Oil ($/Bbl)	94.19	83.86	10.33
Average price ($/Mcfe)	7.12	9.13	(2.01)
Differential to Average NYMEX Henry Hub[2]	(0.46)	0.15	(0.61)
Differential to Average NYMEX WTI[1]	(5.27)	(44.39)	39.12

(1) Including the effects of commodity hedging, the average effective price for the three months ended June 30, 2014 would have been $3.76 per Mcf of gas. The total volume of gas associated with these hedges for the three months ended June 30, 2014 represented approximately 58% of our total sales volumes for the three months ended June 30, 2014. There were no commodity derivatives in place for the three months ended June 30, 2013.

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

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 six months ended June 30, 2014 and 2013.

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	Six Months Ended June 30, 2014	2013	Change
Operating expenses (in thousands):			
Lease operating	$ 4,434	$ 130	$ 4,304
Transportation, gathering and compression	3,853		3,853
Production and ad valorem taxes	1,055	6	1,049
Depletion, depreciation and amortization	21,984	983	21,001
General and administrative	16,823	6,462	10,361
Operating expenses per Mcfe:			
Lease operating	$ 0.61	$ 1.38	$ (0.77)
Transportation, gathering and compression	0.53		0.53
Production and ad valorem taxes	0.15	0.06	0.09
Depletion, depreciation and amortization	3.03	10.47	(7.44)
General and administrative	2.32	68.82	(66.50)

Lease operating expense was $4.4 million in the six months ended June 30, 2014 compared to $0.1 million in the six months ended June 30, 2013. The increase of $4.3 million is attributable to higher production during the six months ended June 30, 2014, as compared to the six months ended June 30, 2013. Lease operating expenses include normally recurring expenses to operate and produce our wells and non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties. We incurred $0.7 million in workover costs, associated primarily with legacy conventional wells, in the six months ended June 30, 2014 compared to $0 in the six months ended June 30, 2013.

Transportation, gathering and compression expense was $3.9 million during the six months ended June 30, 2014 compared to $0 in the six months ended June 30, 2013. These third party costs were higher in the six months ended June 30, 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 $1.1 million in the six months ended June 30, 2014 compared to less than $0.01 million in the six months ended June 30, 2013. Production and ad valorem taxes increased from the six months ended June 30, 2013 to the six months ended June 30, 2014 due to an increase in production volumes subject to production or ad valorem taxes.

Depreciation, depletion and amortization was approximately $22.0 million in the six months ended June 30, 2014 compared to $1.0 million in the six months ended June 30, 2013. The increase in the six months ended June 30, 2014 when compared to the six months ended June 30, 2013 is due to the increase in production during 2014. On a per Mcfe basis, DD&A decreased to $3.03 in the six months ended June 30, 2014 from $10.47 in the six months ended June 30, 2013, which was predominantly driven by a lower depletion rate. The decrease in depletion rate in the six months ended June 30, 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 $16.8 million for the six months ended June 30, 2014 compared to $6.5 million for the six months ended June 30, 2013. The increase of $10.3 million during the six months ended June 30, 2014 when compared to the six months ended June 30, 2013 is primarily due to higher salaries and benefits related to the hiring of a significant number of new employees during the six months ended June 30, 2014. We recorded $0.06 million and $0 of non-cash incentive unit compensation charges for the six months ended June 30, 2014 and 2013, respectively. Our personnel costs will continue to increase as we invest in our technical teams and other staffing to support the expansion of our drilling program in the Utica Core Area and Our Marcellus Project Area.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include exploration expense, accretion expense, and gain on reduction of pension liability. The following table details our other operating expenses for the six months ended June 30, 2014 and 2013.

	Six Months Ended June 30,		
	2014	**2013**	**Change**
Other Operating Expenses (in thousands):			
Exploration	$ 13,840	$ 120	$ 13,720
Accretion of asset retirement obligations	377	117	260
Gain on reduction of pension liability	(2,208)		(2,208)

Exploration expense increased to $13.8 million in the six months ended June 30, 2014 compared to $0.1 million in the six months ended June 30, 2013 due to higher impairment of unproved properties relating to lease expirations, seismic costs, and delay

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rentals due to acreage increases and lease modifications. The following table details our exploration-related expenses for the six months ended June 30, 2014 and 2013.

	Six Months Ended June 30, 2014	2013	Change
Exploration Expenses (in thousands):			
Seismic	$ 359	$ 20	$ 339
Delay rentals	9,686	71	9,615
Dry hole	129	29	100
Impairment of unproved properties	3,666		3,666
	$ 13,840	$ 120	$ 13,720

Impairment of unproved properties was $3.7 million in the six months ended June 30, 2014 compared to $0.0 million in the six months ended June 30, 2013. 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 of asset retirement obligations was $0.4 million in the six months ended June 30, 2014, compared to $0.1 million in the six months ended June 30, 2013. Accretion expense relates to the increase in the asset retirement obligations associated with new wells drilled during the six months ended June 30, 2014 and existing wells acquired in the Oxford Acquisition in June 2013.

Gain on reduction of pension liability was $2.2 million for the six months ended June 30, 2014, compared to $0.0 in the six months ended June 30, 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 fiscal 2013.

Other Income (Expense)

Loss on derivative instruments was $4.5 million for the six months ended June 30, 2014. There was no gain or loss on derivatives in the six months ended June 30, 2013 as the Company did not have derivative instruments in place during this period. Approximately $2.4 million of the $4.5 million loss on derivative instruments related to net cash payments on settled derivatives.

Interest expense, net was $25.3 million for the six months ended June 30, 2014. We incurred $0.5 million in interest expense in six months ended June 30, 2013. The increase in interest expense during the three months ended June 30, 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 $60 million drawn on our Revolving Credit Facility during 2014.

Other income was $1.6 million for the six months ended June 30, 2014 representing the gain on acquisition of Eclipse Operating.

Income tax expense was $94.5 million for the six months ended June 30, 2014 primarily related to a charge to record the initial impact of the change in our tax status as a result of the Corporate Reorganization.

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, the remaining proceeds from our fiscal 2013 issuances of Senior Unsecured Notes, equity units and our IPO. We sell a large portion of our production at the wellhead under floating market contracts.

Six Months Ended June 30, 2014 Compared to the Six Months Ended June 30, 2013

Net cash used in operations in the six months ended June 30, 2014 was $6.1 million compared to $9.4 million in the six months ended June 30, 2013. The decrease in cash used in operating activities from the six months ended June 30, 2014 to the six months ended June 30, 2013 reflects an increase in production, partially offset by higher operating costs. Net cash used in operations is also affected by working capital changes or the timing of cash receipts and disbursements. Changes in working capital (as reflected in our condensed consolidated statements of cash flows) for the six months ended June 30, 2014 was $(8.3) million compared to a $(3.7) million for the six months ended June 30, 2013. The decrease in working capital is primarily due to requirements associated with drilling and exploration.

Net cash used in investing activities in the six months ended June 30, 2014 was $279.0 million compared to $756.6 million in the six months ended June 30, 2013.

During the six months ended June 30, 2014, we:

- spent $279.7 million on related capital expenditures; and
- received net proceeds of $0.8 million related to the acquisition of Eclipse Operating.

During the six months ended June 30, 2013, we:

- spent $651.8 million, net of cash acquired, on the Oxford Acquisition;
- spent $113.2 million on related capital expenditures and unproved properties; and
- received proceeds of $8.5 million from the sale of 1,220 net acres within our area of mutual interest with Antero Resources in Noble County, Ohio.

Net cash provided by financing activities in the six months ended June 30, 2014 decreased to $668.9 million compared to $864.2 million in the six months ended June 30, 2013.

During the six months ended June 30, 2014, we:

- issued shares of common stock in our IPO for proceeds to us totaling approximately $545.4 million, net of $4.6 million of IPO costs; and
- 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.

During the six months ended June 30, 2013, we:

- issued $300.0 million in aggregate principal amount of our Senior Unsecured Notes and incurred $12 million related to discounts; and issued Series A, A-1 and B units for a total of $583.1 million.

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 require substantial capital expenditures.

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 currently believe that net cash generated from the IPO, borrowings activities, capital contributions, remaining proceeds from previous issuances of our Senior Unsecured Notes and equity units and proceeds under our Revolving Credit Facility will be adequate to satisfy near-term financial obligations and liquidity needs. To the extent our capital requirements exceed our internally generated cash flow and proceeds from asset sales, additional debt or equity may be issued to fund these requirements. Long-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 totaled $422.5 million and $400.0 million at June 30, 2014 and December 31, 2013 respectively, and in each case, consisted of our Senior Unsecured Notes.

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 applicable covenants in the Indenture at June 30, 2014.

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 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%

At our option, for the first 2 semi-annual interest payments following the date the notes were first issued, interest may be payable by increasing the principal amount of the Senior Unsecured Notes or by PIK interest. At our option, for the subsequent four semi-annual interest payments thereafter, interest may be payable in the form of 6.0% per annum in cash and 7.0% per annum in PIK interest. Thereafter, interest can only be paid as cash interest. Interest on the Senior Unsecured Notes paid by paying PIK interest accrues at 13.0%, while interest paid by cash accrues at 12.0%. The Company elected to settle its accrued interest payable of $22.5 million with PIK securities on January 15, 2014. As of June 30, 2014, the Company had accrued additional interest in the amount of $23.2 million, which was paid in cash on July 15, 2014.

In February 2014, we entered into our $500 million Revolving Credit Facility. As of May 1, 2014, our borrowing base was increased from $50 million to $100 million. Amounts outstanding under the revolver were repaid on June 25, 2014 with proceeds obtained from our IPO. To ensure our borrowing base more closely conforms to our growth in reserves, the borrowing base under our Revolving Credit Facility is scheduled to be redetermined quarterly on July 1, October 1 of 2014 and January 1 of 2015 and semi-annually thereafter beginning on April 1, 2015 (April and October).

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 production when management believes that favorable future prices can be secured. We currently use a mix of over-the-counter (OTC) natural gas fixed price swaps and put option spreads to manage our exposure to natural gas price fluctuations. 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. The prices contained in these derivative contracts are based on NYMEX Henry Hub prices. Below is summary of our derivative instrument positions as of June 30, 2014 for future production periods:

Description	Volume (MMBtu/d)	Production Period		Weighted Average Swap Price ($/MMBtu)	
Natural Gas Swaps:					
	20,000	July 2014	December 2014	$	4.175
	20,000	January 2015	December 2015	$	4.090

Description:	Volume (MMBtu/d)	Production Period		Weighted Average Strike Price ($/MMBtu)	
Natural Gas Put Spread:					
Purchased put	20,000	June 2014	December 2014	$	4.50
Sold put	20,000	June 2014	December 2014	$	4.00

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Subsequent to June 30, 2014, we entered into the following natural gas basis swaps to lock in the basis differential between our NYMEX Henry Hub swap prices above and Dominion South Point.

Description	Volume (MMBtu/d)	Production Period		Weighted Average Swap Price ($/MMBtu)	
Natural Gas Basis Swaps:					
	25,000	November 14	December 14	$	(1.067)
	25,000	January 15	October 15		(1.166)

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. As of June 30, 2014, our derivative instruments were in a net liability position.

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 six months ended June 30, 2014, costs incurred for drilling projects were $259.8 million compared to $38.0 million for the six months ended June 30, 2013. In the six months ended June 30, 2013, costs incurred for acquisitions of unproved property totaled $683.1 million, primarily in the Utica Core Area. Our capital program for the six months ended June 30, 2013, excluding acquisitions, was funded by net cash flow from operations, proceeds from asset sales and proceeds from the issuances of Senior Unsecured Notes and equity units. Our capital expenditure budget for fiscal 2014 excludes acquisitions, other than leasehold acquisitions, and is currently set at $696.3 million. We expect to fund our capital expenditures in fiscal 2014 with cash generated by operations, borrowings under our Revolving Credit Facility, net proceeds received from our previous issuance of Senior Unsecured Notes, and a portion of our net proceeds from the IPO. 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 June 30, 2014 and December 31, 2013 our total debt and capitalization were as follows (in millions):

	June 30, 2014		December 31, 2013
Senior Unsecured Notes	412.8	$	389.2
Stockholders equity	1,205.8		667.9

Total capitalization	1,618.6	$	1,057.1
Debt to capitalization ratio	25.5%		36.8%

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, derivative obligations and asset retirement obligations. As of June 30, 2014 and December 31, 2013, we do not have any capital leases. As of June 30, 2014 and December 31, 2013, we do not have any significant off-balance sheet debt or other such unrecorded obligations and we have not guaranteed any debt of any unrelated party. The Company s condensed consolidated balance sheet at June 30, 2014 reflects accrued interest payable on our Senior Unsecured Notes of $23.2 million, compared to $20.3 million as of December 31, 2013. We settled $22.4 million of our accrued interest in January 2014 through the issuance of additional Senior Unsecured Notes. The $23.2 million of accrued interest as of June 30, 2014 was paid in cash on July 15, 2014

During 2014 the Company entered into various long-term firm transportation contracts with pipelines in order to sell a portion of its expected natural gas production beginning in 2015. The contracts range in term and extend through 2025 to 2031. The Company s annual commitment is approximately $46 million and is payable per MMbtu of natural gas transported on the pipelines.

We expect to fund these contractual obligations with cash generated from operating activities, borrowings under our Revolving Credit Facility, additional debt issuances and proceeds from asset sales.

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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 72% 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 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 June 30, 2014, we had $412.8 million, as compared to $389.2 million as of December 31, 2013, of Senior Unsecured Notes outstanding 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. The Company elected to settle its accrued interest payable of $22.5 million with PIK securities on January 15, 2014. As of June 30, 2014, the Company had accrued additional interest in the amount of $23.2 million, which was paid in cash on July 15, 2014.

In February 2014, we entered into our $500 million Revolving Credit Facility. As of May 1, 2014, our borrowing base was increased from $50 million to $100 million. Amounts outstanding under the Revolving Credit Facility were repaid on June 25, 2014 with proceeds obtained from our IPO. 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.

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 our costs in fiscal 2014 to continue to be a function of supply and demand.

Non-GAAP Financial Measure

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; and exploration expenses. 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

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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 the 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:

	Three Months ended June 30, 2014		Six Months ended June 30, 2014	
	2014	**2013**	**2014**	**2013**
Net loss	$ (112,648)	$ (5,740)	$ (131,099)	$ (7,499)
Depreciation, depletion & amortization	9,957	495	21,984	983
Exploration Expense	9,295	48	13,840	120
Incentive unit compensation	27		56	
Accretion of asset retirement obligations	191	117	377	117
Gain on reduction of pension liability			(2,208)	
Loss on derivative instruments	863		4,474	
Net cash payment on derivative instruments	(790)		(2,231)	
Net cash paid for option premium	(141)		(141)	
Interest expense	11,618	544	25,254	539
Other income	(1,585)		(1,585)	
Income tax expense	94,541		94,541	
Adjusted EBITDAX	**$ 11,328**	**$ (4,536)**	**$ 23,262**	**$ (5,740)**

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 U.S. 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.

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.

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. For additional discussion, see *Business - Proved Reserves* in our IPO Prospectus.

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 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 to our annual 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 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.

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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 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, 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 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.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market 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 U.S. 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 76% of our June 30, 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 June 30, 2014. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $4.5 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $4.5 million.

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Interest Rate Risk

At June 30, 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 May 1, 2014, our borrowing base was increased from $50.0 million to $100.0 million. All outstanding amounts under the Revolving Credit Facility were repaid on June 25, 2014 with a portion of our proceeds from our IPO.

ITEM 4. 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 Quarterly Report on Form 10-Q. 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 Quarterly Report on Form 10-Q, 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.

In addition, the Company s management carried out an evaluation, as required by Rule 13a-15(d) of the Exchange Act, with the participation of the President and Chief Executive Officer and Executive Vice President and Chief Financial Officer, of changes in the Company s internal control over financial reporting. Based on this evaluation, the President and Chief Executive Officer and Executive Vice President and Chief Financial Officer concluded that there were no changes in the Company s internal control over financial reporting that occurred during the quarter ended June 30, 2014 that have materially affected, or that are reasonably likely to materially affect, the Company s internal control over financial reporting.

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PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Information regarding the Company s legal proceedings is set forth in Note 12 *Commitments and Contingencies* located in the Notes to the Condensed Consolidated Financial Statements included in Item 1 of Part I of this Quarterly Report on Form 10-Q and is incorporated herein by reference.

Item 1A. Risk Factors

In addition to the other information set forth in this Quarterly Report on Form 10-Q, you should carefully consider the factors discussed in Risk Factors in our final prospectus dated June 19, 2014 and filed with the SEC pursuant to Rule 424(b)(4) of the Securities Act on June 23, 2014, which could materially affect our business, financial condition, and/or future results. The risks described in our final prospectus are not the only risks we face. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or results of operations.

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

Unregistered Sales of Equity Securities

There were no sales of unregistered equity securities during the period covered by this report other than as previously included in a Current Report on Form 8-K.

Use of Proceeds

On June 25, 2014, we completed our IPO of common stock pursuant to our Registration Statement on Form S-1, as amended (File No. 333-195679), which was declared effective by the SEC on June 19, 2014. Citigroup Global Markets Inc., Goldman, Sachs & Co., Morgan Stanley & Co. LLC, Barclays Capital Inc., BMO Capital Markets Corp., Deutsche Bank Securities Inc., KeyBanc Capital Markets Inc. and RBC Capital Markets, LLC acted as the joint book-running managers in the IPO. Pursuant to the Registration Statement, we registered the offer and sale 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 selling stockholders. The sale of the shares in our IPO closed on June 25, 2014, and our IPO terminated upon completion of the closing.

The gross proceeds of our IPO, based on the public offering price of $27.00 per share, were approximately $818.1 million, which resulted in net proceeds to us of approximately $545.4 million after deducting expenses and underwriting discounts and commissions of approximately $35.1 million. We did not receive any proceeds from the sale of the shares by the certain selling stockholders. The net proceeds we received from our IPO were used to repay all of the then outstanding borrowings under our revolving credit facility, and we expect to use the remaining net proceeds to fund a portion of our capital expenditure plan.

ITEM 6. EXHIBITS

See the list of exhibits in the index to exhibits to this Quarterly Report on Form 10-Q, which is incorporated herein by reference.

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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.

August 14, 2014	ECLIPSE RESOURCES CORPORATION. (Registrant)
	/s/ Benjamin W. Hulburt Benjamin W. Hulburt, Chairman, President and Chief Executive Officer
	/s/ Matthew R. DeNezza Matthew R. DeNezza, Executive Vice President and Chief Financial Officer

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ECLIPSE RESOURCES CORPORATION

INDEX TO EXHIBITS

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	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	Registration Rights 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 10.2 to the Company s Current Report on Form 8-K filed with the SEC on June 30, 2014).
10.1	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).
10.2	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).
10.3	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).
10.4	First Amendment to Credit Agreement, dated as of April 10, 2014, by and among Eclipse Resources I, LP, Bank of Montreal, as administrative agent, KeyBank National Association, as syndication agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.5 to the Company s Registration Statement on Form S-1 filed with the SEC on May 5, 2014).
10.5	Second Amendment to Credit Agreement, dated as of April 24, 2014, among Eclipse Resources I, LP, Bank of Montreal, as administrative agent, KeyBank National Association, as syndication agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.6 to the Company s Registration Statement on Form S-1 filed with the SEC on May 5, 2014).

10.6	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).
10.7	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).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) of the Exchange Act, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1**	Certifications of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

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32.2**	Certifications of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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.

** These exhibits are furnished herewith and shall not be deemed filed for purposes of Section 18 of the Exchange Act, or otherwise subject to the liability of that section, and shall not be deemed to be incorporated by reference into any filing under the Securities Act or the Exchange Act.

§ These exhibits are furnished herewith. In accordance with Rule 406T of Regulation S-T, these exhibits are not deemed to be filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act, are not deemed to be filed for purposes of Section 18 of the Exchange Act, and otherwise are not subject to liability under these sections.