Eclipse Resources Corp
Form 10-Q
August 14, 2015
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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, 2015

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. x Yes ¨ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). x Yes ¨ No

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

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, 2015: 222,668,788 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 in Item 1A. Risk Factors of our Annual Report on Form 10-K, filed with the Securities Exchange Commission (the SEC) on March 9, 2015.

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

- our business strategy;
- reserves;
- general economic conditions;
- financial strategy, liquidity and capital required for developing our properties and timing related thereto;
- realized natural gas, NGLs and oil prices;
- timing and amount of future production of natural gas, NGLs and oil;
- our hedging strategy and results;
- future drilling plans;
- competition and government regulations, including those related to hydraulic fracturing;
- the anticipated benefits under our commercial agreements;

- pending legal matters relating to our leases;
- marketing of natural gas, NGLs and oil;
- leasehold and business acquisitions;
- the costs, terms and availability of gathering, processing, fractionation and other midstream services;
- credit markets;
- uncertainty regarding our future operating results, including initial production rates and liquid yields in our type curve areas; and
- plans, objectives, expectations and intentions contained in this 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, risks associated with our level of indebtedness, the timing of development expenditures, and the other risks described in Item 1A. Risk Factors of our Annual Report on Form 10-K, filed with the SEC on March 9, 2015.

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.

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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.

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, LP, Eclipse Resources-Ohio, LLC, and Eclipse Resources Operating, LLC;

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

Eclipse Holdings refers to Eclipse Resources Holdings, LP;

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

EnCap refers to EnCap Investments LP;

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

Glossary of Oil and Natural Gas Terms

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

Bbls/d Bbls per day;

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

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

Boe/d Boes per day;

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

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

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

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

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

Dry Gas Area or Dry Gas Window refers to both the Dry Gas West and the Dry Gas East areas;

Dry Gas East or Dry Gas East Window refers to the area in which we expect Utica Shale wells to produce natural gas having a heat content of less than approximately 1,025 Btu with a negligible initial condensate yield;

Dry Gas West or Dry Gas West Window refers to the area in which we expect Utica Shale wells to produce natural gas having a heat content of less than approximately 1,050 Btu with a negligible initial condensate yield;

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

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

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

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

Formation A layer of rock that has distinct characteristics that differs from nearby rock;

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

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

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

MBbl One thousand barrels;

MBoe One thousand Boe;

Mcf One thousand cubic feet;

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

Mcf/d Mcfs per day;

MMBbls One million barrels;

MMBoe   One million Boe;

MMBtu   One million British thermal units;

MMcf   One million cubic feet;

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

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

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

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

NYMEX   The New York Mercantile Exchange;

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

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

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

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

Proved undeveloped reserves refers to proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion;

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

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

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

PV-10 refers to, when used with respect to natural gas and oil reserves, the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using sales prices used in estimating proved oil and gas reserves and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC;

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

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

Rich Condensate or Rich Condensate Window refers to the area within the Utica Core Area in which we expect the Utica Shale wells to produce natural gas having a heat content of approximately 1,300 Btu, with an initial condensate yield of approximately 175 barrels per MMcf of natural gas produced;

Rich Gas refers to the area within the Utica Core Area in which we expect the Utica Shale wells to produce natural gas having a heat content of approximately 1,200 Btu, with an initial condensate yield of approximately 15 barrels per MMcf of natural gas produced;

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

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

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

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

Unit The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement;

Wellbore refers to the hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called well or borehole;

Working interest The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis;

WTI West Texas Intermediate; and

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

ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(In thousands, except share and per share amounts)

(Unaudited)

	June 30, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 257,622	$ 67,517
Accounts receivable	32,962	46,378
Assets held for sale	3,618	20,673
Other current assets	12,309	19,711
Total current assets	306,511	154,279
PROPERTY AND EQUIPMENT, AT COST		
Oil and natural gas properties, successful efforts method		
Unproved properties	1,003,018	1,044,469
Proved properties, net	827,480	670,255
Other property and equipment, net	8,836	8,103
Total property and equipment, net	1,839,334	1,722,827
OTHER NONCURRENT ASSETS		
Debt issuance costs, net of $3.5 million and $2.5 million of amortization, respectively	6,617	6,058
Other assets	1,436	1,782
TOTAL ASSETS	$ 2,153,898	$ 1,884,946
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 82,282	$ 137,415
Accrued capital expenditures	20,470	51,360
Accrued liabilities	21,525	13,576
Accrued interest payable	26,266	25,187
Deferred income taxes	3,624	5,246
Total current liabilities	154,167	232,784

NONCURRENT LIABILITIES		
Debt, net of unamortized discount of $7.4 million and $8.5 million, respectively	429,995	414,016
Pension obligations	1,449	1,321
Asset retirement obligations	18,488	17,400
Other liabilities	2,560	
Deferred income taxes	34,229	66,714
Total liabilities	640,888	732,235
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock, 50,000,000 shares authorized, no shares issued and outstanding		
Common stock, $0.01 par value, 1,000,000,000 shares authorized, 222,663,611 and 160,031,115 shares issued and outstanding, respectively	2,226	1,600
Additional paid in capital	1,826,768	1,391,004
Accumulated deficit	(315,418)	(239,345)
Accumulated other comprehensive loss	(566)	(548)
Total stockholders equity	1,513,010	1,152,711
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 2,153,898	$ 1,884,946

The accompanying notes are an integral part of these condensed 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, 2015	For the Three Months Ended June 30, 2014	For the Six Months Ended June 30, 2015	For the Six Months Ended June 30, 2014
REVENUES				
Oil and natural gas sales	$ 64,984	$ 26,955	$ 111,598	$ 51,743
Brokered natural gas and marketing	9,469		6,669	
Total revenues	74,453	26,955	118,267	51,743
OPERATING EXPENSES				
Lease operating	3,589	2,643	6,935	4,434
Transportation, gathering and compression	22,634	2,949	35,085	3,853
Production and ad valorem taxes	3,078	702	5,178	1,055
Brokered natural gas and marketing	10,795		10,795	
Depreciation, depletion and amortization	60,641	9,957	103,073	21,984
Exploration	6,243	9,295	19,696	13,840
General and administrative	12,717	8,429	24,660	16,823
Rig termination	366		7,423	
Accretion of asset retirement obligations	399	191	785	377
Gain on sale of assets	(5,553)		(5,473)	
Gain on reduction of pension obligations				(2,208)
Total operating expenses	114,909	34,166	208,157	60,158
OPERATING LOSS	(40,456)	(7,211)	(89,890)	(8,415)
OTHER INCOME (EXPENSE)				
Gain (loss) on derivative instruments	(3,523)	(863)	7,848	(4,474)
Interest expense, net	(14,401)	(11,618)	(28,422)	(25,254)
Other income (expense)	(2)	1,585	400	1,585
Total other expense, net	(17,926)	(10,896)	(20,174)	(28,143)
LOSS BEFORE INCOME TAXES	(58,382)	(18,107)	(110,064)	(36,558)
INCOME TAX BENEFIT (EXPENSE)	16,412	(94,541)	33,991	(94,541)
NET LOSS	$ (41,970)	$ (112,648)	$ (76,073)	$ (131,099)
NET LOSS PER COMMON SHARE				

Basic and diluted	$	(0.19)	$	(0.84)	$	(0.36)	$	(1.02)
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING								
Basic and diluted		222,502		134,309		213,178		128,480

The accompanying notes are an integral part of these condensed 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,	
	2015	2014	2015	2014
NET LOSS	$ (41,970)	$ (112,648)	$ (76,073)	$ (131,099)
Other comprehensive income (loss):				
Pension obligation adjustment, net of tax	192	(371)	(18)	(1,233)
TOTAL COMPREHENSIVE LOSS	$ (41,778)	$ (113,019)	$ (76,091)	$ (132,332)

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

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ECLIPSE RESOURCES CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY

(In thousands, except share amounts)

(Unaudited)

	Number of Shares	Common Stock ($0.01 Par Value)	Additional Paid-in-Capital	Accumulated Deficit	Accumulated Other Comprehensive Loss	Total
Balances, December 31, 2014	160,031,115	$ 1,600	$ 1,391,004	$ (239,345)	$ (548)	$ 1,152,711
Shares of common stock issued in private placement, net of offering costs	62,500,000	625	433,608			434,233
Stock-based compensation			2,157			2,157
Issuance of restricted stock	132,496	1	(1)			
Pension obligation adjustment, net of tax					(18)	(18)
Net loss				(76,073)		(76,073)
Balances, June 30, 2015	222,663,611	$ 2,226	$ 1,826,768	$ (315,418)	$ (566)	$ 1,513,010

The accompanying notes are an integral part of these condensed 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, 2015	2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net loss	$ (76,073)	$ (131,099)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation, depletion and amortization	103,073	21,984
Exploration expense	6,073	3,795
Pension benefit costs	101	111
Stock-based compensation	2,157	56
Accretion of asset retirement obligations	785	377
Gain on reduction of pension obligation		(2,208)
Loss (gain) on derivative instruments	(7,848)	4,474
Net cash received (paid) on settled derivatives	14,422	(2,231)
Net cash paid for option premium		(141)
Gain on sale of assets	(5,473)	(1,585)
Deferred income taxes	(34,107)	94,541
Interest not paid in cash	1,232	2,166
Amortization of deferred financing costs	1,018	885
Amortization of debt discount	1,193	1,115
Changes in operating assets and liabilities, net of acquisitions:		
Accounts receivable	13,007	(31,795)
Other assets	225	(883)
Accounts payable and accrued liabilities	29,724	26,294
Accrued liabilities related parties		(1,951)
Net cash provided by (used in) operating activities	49,509	(16,095)
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures on oil and natural gas properties	(327,856)	(268,205)
Additions to other property and equipment	(1,284)	(1,454)
Acquisition of business, net of cash acquired		754
Proceeds from the sale of assets	37,287	
Net cash used in investing activities	(291,853)	(268,905)
CASH FLOWS FROM FINANCING ACTIVITIES		
Debt issuance costs	(1,577)	(1,122)

Repayments of long-term debt		(207)		(62)
Capital contributions				124,667
Proceeds from issuance of common stock, net of underwriting fees		440,000		550,025
Equity issuance costs		(5,767)		(4,597)
Net cash provided by financing activities		432,449		668,911
Net increase in cash and cash equivalents		190,105		383,911
Cash and cash equivalents at beginning of period		67,517		109,509
Cash and cash equivalents at end of period	$	257,622	$	493,420
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:				
Cash paid for interest	$	13,080	$	448
Cash paid for income taxes	$	37	$	
SUPPLEMENTAL DISCLOSURE OF NON-CASH ACTIVITIES:				
Asset retirement obligations incurred, including changes in estimate	$	303	$	102
Additions of other property through debt financing	$	888	$	507
Additions to oil and natural gas properties changes in accounts payable, accrued liabilities, and accrued capital expenditures	$	(88,418)	$	78,890
Interest paid-in-kind	$	14,786	$	22,461

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

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ECLIPSE RESOURCES CORPORATION

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

Note 1 Organization and Nature of Operations

Eclipse Resources Corporation (the Company) is an independent exploration and production company 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.

Note 2 Basis of Presentation

The accompanying condensed consolidated financial statements, which are unaudited except the condensed consolidated balance sheet at December 31, 2014 which is derived from the Company s audited financial statements, and are presented in accordance with the requirements of 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 consolidated financial statements, and notes to those statements, included in the Company s Annual Report on Form 10-K filed with the SEC on March 9, 2015.

Operating results for interim periods may not necessarily be indicative of the results of operations for the full year ending December 31, 2015 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 depreciation, depletion and amortization and impairment of capitalized costs of oil and natural gas properties;

- estimates of asset retirement obligations;

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

- impairment of undeveloped properties and other assets; and depreciation and depletion of property and equipment.

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

Note 3 Summary of Significant Accounting Policies

(a) Cash and Cash Equivalents

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

(b) Accounts Receivable

Accounts receivable are carried at estimated net realizable value. Receivables deemed uncollectible are charged directly to expense. Trade credit is generally extended on a short-term basis, and therefore, accounts receivable do not bear interest, although a finance charge may be applied to such receivables that are past due. A valuation allowance is provided for those accounts for which collection is estimated as doubtful and uncollectible accounts are written off and charged against the allowance. In estimating the allowance, management considers, among other things, how recently and how frequently payments have been received and the financial position of the counterparty. The Company did not deem any of its accounts receivables to be uncollectible as of June 30, 2015 or December 31, 2014.

The Company accrues revenue due to timing differences between the delivery of natural gas, natural gas liquids (NGLs), and crude oil and the receipt of a delivery statement. These revenues are recorded based upon volumetric data from the Company s records and management s estimates of the related commodity sales and transportation and compression fees. The Company had $27.5 million and $24.1 million of accrued revenues, net of certain expenses at June 30, 2015 and December 31, 2014, 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 disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense (see *Depreciation, Depletion and Amortization* below).

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

Upon the sale or retirement of a complete field of a proved property, the cost is eliminated from the property accounts, and the resultant gain or loss is reclassified to the Company s 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.

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

	June 30, 2015	December 31, 2014
Oil and natural gas properties:		
Unproved	$ 1,003,018	$ 1,044,469
Proved	1,060,823	802,112
Gross oil and natural gas properties	2,063,841	1,846,581
Less accumulated depreciation, depletion and amortization	(233,343)	(131,857)

Oil and natural gas properties, net	1,830,498	1,714,724
Other property and equipment	11,991	8,912
Less accumulated depreciation	(3,155)	(809)
Other property and equipment, net	8,836	8,103
Property and equipment, net	$ 1,839,334	$ 1,722,827

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.

Other Property and Equipment

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

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(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 and 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 did not have any material imbalances as of June 30, 2015 or December 31, 2014.

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.

Brokered natural gas and marketing revenues include revenues from brokered gas or revenue we receive as a result of selling and buying natural gas that is not related to our production and revenue from the release of transportation capacity. We realize brokered margins as a result of buying and selling natural gas utilizing separate purchase and sale transactions, typically with separate counterparties, whereby the Company or the counterparty takes title to the natural gas purchased or sold. Revenues and expenses related to brokering natural gas are reported gross as part of revenue and expense in accordance with U.S. GAAP. We consider these activities as ancillary to our natural gas sales and thus report them within one operating segment.

(e) Major Customers

The Company sells production volumes to various purchasers. For the three and six months ended June 30, 2015, there were three and four customers, respectively, that, on an individual basis, accounted for 10% or more of the Company s natural gas, NGLs and oil sales. For the three and six months ended June 30, 2014, there was one customer that accounted for 10% or more of the Company s total natural gas, NGLs and oil sales. 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,	
	2015	2014	2015	2014
Purchaser				
Antero Resources Corporation	19%	73%	20%	63%
ARM Energy Management			13%	
Enlink Midstream	34%		30%	
Sequent Energy Management	22%		13%	
Total	75%	73%	76%	63%

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 because it believes that there are potential alternative purchasers and that it may be necessary to establish relationships with new purchasers. However, there can be no assurance that the Company can establish such relationships or that those relationships will result in an increased number of purchasers.

(f) Concentration of Credit Risk

Although the Company is exposed to a concentration of credit risk due to the fact that several customers account for a significant portion of its total natural gas, NGLs and oil sales, management believes that all of the Company s purchasers are credit worthy. The following table summarizes concentration of receivables, net of allowances, by product or service as of June 30, 2015 and December 31, 2014 (in thousands):

	June 30, 2015	December 31, 2014
Receivables by product or service:		
Sale of oil and natural gas and related products and services	$ 25,645	$ 22,777
Joint interest owners	5,019	20,666
Miscellaneous other	2,298	2,935
Total	$ 32,962	$ 46,378

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Oil and natural gas customers include pipelines, distribution companies, producers, gas marketers and industrial users primarily located in the State of Ohio. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly. By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, the Company exposes itself to the credit risk of counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe the Company, which creates credit risk. To minimize the credit risk in derivative instruments, it is the Company s policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. Additionally, the Company uses master netting agreements to minimize credit-risk exposure. The creditworthiness of the Company s counterparties is subject to periodic review. The fair value of the Company s commodity derivative contracts is a net asset position of $11.5 million at June 30, 2015 and a net asset position $19.0 million as December 31, 2014. Other than as provided by the revolving credit facility, the Company is not required to provide credit support or collateral to any of its counterparties under the Company s contracts, nor are they required to provide credit support to the Company. As of June 30, 2015 and December 31, 2014, the Company did not have past-due receivables from or payables to any of the counterparties.

(g) Accumulated Other Comprehensive Income (Loss)

Comprehensive loss includes net loss and all other changes in the equity of a business during a period from transactions and other events and circumstances from non-owner sources that, under U.S. GAAP, have not been recognized in the calculation of net loss. These changes, other than net loss, are referred to as other comprehensive loss and for the Company they include a pension benefit plan that requires the Company to (i) recognize the overfunded or underfunded status of a defined benefit retirement plan as an asset or liability in its consolidated balance sheet and (ii) recognize changes in that funded status in the year in which the changes occur through other comprehensive loss. The Company s pension plan was underfunded by $1.4 million and $1.3 million at June 30, 2015 and December 31, 2014, respectively. Effective March 31, 2014, benefit accruals in the plan were frozen resulting in a gain on reduction of pension obligations of $2.2 million for the six months ended June 30, 2014.

(h) Depreciation, Depletion and Amortization

Oil and Natural Gas Properties

Depreciation, depletion, and amortization (DD&A) of capitalized costs of proved oil and natural gas properties is computed using the unit-of-production method on a field level basis using total estimated proved reserves. The reserve base used to calculate DD&A for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate DD&A for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves. DD&A expense relating to proved oil and natural gas properties for the three months ended June 30, 2015 and 2014 totaled approximately $60.1 million and $9.9 million, respectively; and for the six months ended June 30, 2015 and 2014 totaled approximately $102.2 million and $21.8 million, respectively.

Through September 30, 2014, the Company calculated depletion of proved properties at the individual unit level. Effective October 1, 2014, the Company changed its estimate for calculating depletion expense of proved properties to be performed at the field level consistent with the assessment for impairment of proved property costs.

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, 2015 and 2014 totaled approximately $0.5 million and less than $0.1 million, respectively; and for the six months ended June 30, 2015 and 2014 totaled approximately $0.8 million and $0.2 million, 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.

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

The review for impairment of the Company s oil and gas properties is done by determining if the historical cost of proved properties less the applicable accumulated DD&A and abandonment is less than the estimated expected undiscounted future cash flows. The expected future cash flows are estimated based on the Company s plans to continue to produce and develop proved reserves and a risk-adjusted portion of probable reserves. Expected future cash flow from the sale of production of reserves is calculated based on estimated future prices. The Company estimates prices based upon current contracts in place, adjusted for basis differentials and market-related information, including published futures prices. The estimated future level of production is based on assumptions surrounding future prices and costs, field decline rates, market demand and supply and the economic and regulatory climates. If the carrying value exceeds the expected future cash flows, an impairment loss is recognized for the difference between the estimated fair market value (as determined by discounted future cash flows) and the carrying value of the assets. There were no impairments of proved properties for the three or six months ended June 30, 2015 and 2014.

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

Unproved properties are reviewed annually for impairment or whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. An impairment charge is recorded if conditions indicate the Company will not explore the acreage prior to expiration of the applicable leases. The Company recorded impairment charges of unproved oil and gas properties related to lease expirations of $4.4 million and $6.0 million for the three and six months ended June 30, 2015, respectively. The Company recorded $3.7 million to impairment of unproved oil and gas properties related to lease expirations for each of the three and six months ended June 30, 2014. These costs are included in exploration expense in the condensed consolidated statements of operations.

(j) Income Taxes

The Company accounts for income taxes under the liability method as set out in the FASB s Accounting Standards Codification (ASC) Topic 740 Income Taxes. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases, operating losses and other tax attribute carry-forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. The Company recognizes fines and penalties as income tax expense.

Upon the closing of the Corporate Reorganization, the Company acquired 100% of Eclipse I, Eclipse Resources-Ohio, LLC and Eclipse Operating. Eclipse I was a limited partnership not subject to federal income taxes before the

Corporate Reorganization. However, in connection with the closing of the Corporate Reorganization, the Company became a corporation subject to federal and state income tax and, as such, the Company s future income taxes will be dependent upon its future taxable income. The change in tax status requires the recognition of a deferred tax asset or liability for the initial temporary differences at the time of the change in status. The resulting net deferred tax liability of approximately $97.6 million was recorded as income tax expense in the consolidated statements of operations for the year ended December 31, 2014.

ASC Topic 740 further 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 has not recorded a reserve for any uncertain tax positions to date.

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(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.

(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.

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

(m) Asset Retirement Obligation

The Company recognizes a legal liability for its asset retirement obligations (ARO) in accordance with Topic ASC 410, *Asset Retirement and Environmental Obligations*, associated with the retirement of a tangible long-lived asset, in the period in which it is incurred or becomes determinable, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. The Company measures the fair value of its ARO using expected future cash outflows for abandonment discounted back to the date that the abandonment obligation was measured using an estimated credit adjusted rate, which was 10.45% and 8.96% for the six months ended June 30, 2015 and 2014, respectively.

Estimating the future ARO requires management to make estimates and judgments based on historical estimates regarding timing and existence of a liability, as well as what constitutes adequate restoration, inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

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The following table sets forth the changes in the Company s ARO liability for the six months ended June 30, 2015 (in thousands):

	Six Months Ended June 30, 2015
Asset retirement obligations, beginning of period	$ 17,400
Additional liabilities incurred	303
Accretion	785
Asset retirement obligations, end of period	$ 18,488

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

(n) Lease Obligations

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

(o) Off-Balance Sheet Arrangements

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

(p) Segment Reporting

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

(q) Debt Issuance Costs

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

(r) Recent Accounting Pronouncements

The FASB issued ASU 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, 2017, including interim periods within that reporting period. The Company is evaluating the impact of the adoption on its financial position, results of operations and related disclosures.

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In April 2014, the FASB issued ASU 2014-08, *Presentation of Financial Statements (Topic 205) and Property, Plant, and Equipment (Topic 360) : Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity* . The objective of the amendments in this update is to change the criteria for reporting discontinued operations and enhance convergence of the FASB s and the International Accounting Standard Board s (IASB) reporting requirements for discontinued operations. The amendments in this update change the requirements for reporting discontinued operations in Subtopic 205-20. A discontinued operation may include a component of an entity or a group of components of an entity, or a business or nonprofit activity. A disposal of a component of an entity or a group of components of an entity is required to be reported in discontinued operations if the disposal represents a strategic shift that has (or will have) a major effect on an entity s operations and financial results. The amendments in this update require an entity to present, for each comparative period, the assets and liabilities of a disposal group that includes a discontinued operation separately in the asset and liability sections, respectively, of the statement of financial position. The amendments in this update also require additional disclosures about discontinued operations. Public business entities must apply the amendments in this update prospectively to both of the following: (1) All disposals (or classifications as held for sale) of components of an entity that occur within annual periods beginning on or after December 15, 2014, and interim periods within those years; (2) All businesses or nonprofit activities that, on acquisition, are classified as held for sale that occur within annual periods beginning on or after December 15, 2014, and interim periods within those years. Early adoption is permitted, but only for disposals (or classifications as held for sale) that have not been reported in financial statements previously issued or available for issuance. The adoption of this update did not have a significant impact on the Company s financial position, results of operations and related disclosures.

In April 2015, the FASB issued ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs, which expands upon the guidance on the presentation of debt issuance costs. The ASU requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with debt discounts. This guidance requires retrospective application and is effective for fiscal years beginning after December 15, 2015 and for interim periods within those fiscal years, with early adoption permitted.

(s) Cash Flow Revision

The Company revised the presentation of delay rentals and geological and geophysical costs within the condensed consolidated statement of cash flows for the six months ended June 30, 2014, to conform to the current period presentation. Previously, such costs had been presented as cash outflows from investing activities; however, U.S. GAAP requires such costs to be presented as cash outflows from operating activities. This revision resulted in a reduction to cash flows provided by operating activities and a corresponding reduction to cash flows used in investing activities of approximately $10 million compared to the previously reported amounts. The Company evaluated the materiality of this error on both a quantitative and qualitative basis under the guidance of ASC 250 - Accounting Changes and Error Corrections and determined that it did not have a material impact to previously issued financial statements.

Note 4 Sale of Oil and Natural Gas Property Interests

During the three months ended June 30, 2015, the Company completed the sale of a central processing facility and certain pipelines. The transaction resulted in proceeds of $37.3 million and a gain on sale of assets of $5.6 million, which was recorded during the three months ended June 30, 2015. Approximately $3.6 million of costs related to other pipelines were classified as assets held for sale in the condensed consolidated balance sheets as of June 30, 2015.

Note 5 Derivative Instruments

Commodity Derivatives

The Company is exposed to market risk from changes in energy commodity prices within its operations. The Company utilizes derivatives to manage exposure to the variability in expected future cash flows from forecasted sales of natural gas and oil. The Company currently uses a mix of over-the-counter (OTC) fixed price swaps, basis swaps and put options spreads and collars to manage its exposure to commodity price fluctuations. All of the Company s derivative instruments are used for risk management purposes and none are held for trading or speculative purposes.

The Company is exposed to credit risk in the event of non-performance by counterparties. To mitigate this risk, the Company enters into derivative contracts only with counterparties that are rated A or higher by S&P or Moody s. The creditworthiness of

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counterparties is subject to periodic review. As of June 30, 2015, the Company s derivative instruments were with Bank of Montreal and Key Bank, N.A. The Company has not experienced any issues of non-performance by derivative counterparties. Below is a summary of the Company s derivative instrument positions, as of June 30, 2015, for future production periods:

Natural Gas Derivatives

Description	Volume (MMBtu/d)	Production Period		Weighted Average Price ($/MMBtu)	
Natural Gas Swaps:					
	62,500	July 2015	December 2015	$	3.78
	25,000	January 2016	December 2016	$	3.66
	7,000	July 2015	October 2015	$	2.84
Natural Gas Three-way Collar:					
Floor purchase price (put)	15,000	July 2015	December 2015	$	3.60
Ceiling sold price (call)	15,000	July 2015	December 2015	$	3.80
Floor sold price (put)	15,000	July 2015	December 2015	$	3.00
Natural Gas Put Options:					
Put sold	16,800	July 2015	December 2015	$	3.35
Put sold	16,800	July 2015	October 2015	$	2.87
Put purchased	16,800	July 2015	October 2015	$	3.35
Put sold	16,800	January 2016	December 2016	$	2.75
Basis Swaps:					
	25,000	July 2015	October 2015	$	(1.21)

Oil Derivatives

Description	Volume (Bbls/d)	Production Period		Weighted Average Price ($/Bbl)	
Oil Collar:					
Floor purchase price (put)	3,000	July 2015	February 2016	$	55.00
Ceiling sold price (call)	3,000	July 2015	February 2016	$	61.40
Oil Three-way Collar:					
Floor purchase price (put)	1,000	March 2016	December 2016	$	60.00
Ceiling sold price (call)	1,000	March 2016	December 2016	$	70.10
Floor sold price (put)	1,000	March 2016	December 2016	$	45.00

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). None of the derivative instruments are designated as hedges for accounting purposes.

Derivatives not designated as hedging instruments under ASC 815	Gross Amount	Netting Adjustments(a)	Net Amount Presented in the Balance Sheets	Balance Sheet Location
As of June 30, 2015				
Assets				
Commodity derivatives current	$ 16,742	$ (6,549)	$ 10,193	Other current assets
Commodity derivatives noncurrent	2,859	(1,541)	1,318	Other assets
Total assets	$ 19,601	$ (8,090)	$ 11,511	
Liabilities				
Commodity derivatives current	$ (6,549)	$ 6,549	$	
Commodity derivatives noncurrent	(1,541)	1,541		
Total liabilities	$ (8,090)	$ 8,090	$	

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Derivatives not designated as hedging instruments under ASC 815	Gross Amount	Netting Adjustments(a)	Net Amount Presented in the Balance Sheets	Balance Sheet Location
As of December 31, 2014				
Assets				
Commodity derivatives current	$ 22,349	$ (5,012)	$ 17,337	Other current assets
Commodity derivatives noncurrent	1,741	(44)	1,697	Other assets
Total assets	$ 24,090	$ (5,056)	$ 19,034	
Liabilities				
Commodity derivatives current	$ (5,012)	$ 5,012	$	
Commodity derivatives noncurrent	(44)	44		
Total liabilities	$ (5,056)	$ 5,056	$	

(a) The Company has agreements in place that allow for the financial right to offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

The following table presents the Company s reported gains and losses on derivative instruments and where such values are recorded in the condensed consolidated statements of operations for the periods presented (in thousands):

		Amount of Gain (Loss) Recognized in In			
		Three months ended June 30,		Six months ende June 30,	
erivatives not designated as hedging instruments under ASC 815	Location of Gain (Loss) Recognized in Income	2015	2014	2015	2014
ommodity derivatives	Gain (loss) on derivative instruments	$ (3,523)	$ (863)	$ 7,848	$ (4,47

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.

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 the Company s derivative instruments 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, 2015: (in thousands)				
Commodity derivative instruments	$	$ 11,511	$	$ 11,511
Total	$	$ 11,511	$	$ 11,511

	Level 1	Level 2	Level 3	Total Fair Value
As of December 31, 2014: (in thousands)				
Commodity derivative instruments	$	$ 19,034	$	$ 19,034
Total	$	$ 19,034	$	$ 19,034

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Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and natural gas property acquired include the Company s estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine the inception value of the Company s AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company s ARO represent a nonrecurring Level 3 measurement. (See Note 3 *Summary of Significant Accounting Policies*).

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. (See Note 3 *Summary of Significant Accounting Policies*).

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

As of June 30, 2015, the Company had a principal amount of $437.3 million, compared to $422.5 million as of December 31, 2014, related to the Senior Unsecured PIK Notes due in 2018 (the Senior PIK Notes). The Company elected to settle its accrued interest payable on January 15, 2015 by issuing PIK securities of $14.8 million and a cash payment of $12.7 million. During the three months ended June 30, 2015 and 2014, the Company amortized $0.5 million and $0.6 million of deferred financing costs and debt discount to interest expense, respectively, using the effective interest method. During the six months ended June 30, 2015 and 2014, the Company amortized $2.2 million and $2.0 million of deferred financing costs and debt discount to interest expense, respectively, using the effective interest method. The Company redeemed all of the outstanding balance of the 12% Senior PIK Notes on July 13, 2015 for approximately $510.7 million, including outstanding principal balance, a make-whole premium, and accrued interest.

The Indenture governing the Senior PIK Notes required 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 placed 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, 2015 and December 31, 2014.

8.875% Senior Unsecured Notes Due 2023

On July 6, 2015, the Company issued $550 million in aggregate principal amount of 8.875% senior notes due 2023 (the Notes) at an issue price of 97.903% of the principal amount of the Notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the Notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S under the Securities Act. Upon closing, the Company received proceeds of approximately $525.5 million, after deducting original issue discount, the initial purchasers discounts and estimated offering expenses, of which the Company used approximately $510.7 million to finance the redemption of all of its outstanding Senior PIK Notes. The Company intends to use the remaining net proceeds to fund its capital expenditure plan and for general corporate purposes.

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 semiannual redeterminations. At June 30, 2015, the borrowing base was $125 million and the Company had no outstanding borrowings. After giving effect to outstanding letters of credit issued by the Company totaling $27.8 million, the Company had available borrowing capacity under the Revolving Credit Facility of $97.2 million at June 30, 2015.

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The Revolving Credit Facility was amended and restated on January 12, 2015. The primary change effected by the Amendment was to add Eclipse Resources Corporation as a party to the Revolving Credit Facility and thereby subject the Company to the representations, warranties, covenants and events of default provisions thereof. Relative to the Eclipse I s previous credit agreement, the Credit Agreement also (i) requires financial reporting regarding, and tests financial covenants with respect to, Eclipse Resources Corporation rather than Eclipse I, (ii) increases the basket sizes under certain of the negative covenants, and (iii) includes certain other changes favorable to Eclipse I. Other terms of the Credit Agreement remain generally consistent with Eclipse I s previous credit agreement.

The Revolving Credit Facility was further amended and restated on June 11, 2015 and became effective upon the issuance of the Notes. Among other things, pursuant to the Amended Credit Agreement, the Company assumed all of the rights and obligations of Eclipse I as the borrower under the Existing Credit Agreement. Furthermore, the Amended Credit Agreement allowed for the issuance of the Notes and provided that the Company would not incur an immediate reduction in borrowing base under its Revolving Credit Facility as a result of the issuance of the Notes. Accordingly, the borrowing base under the Company s revolving credit facility immediately following the issuance of the Notes remained at $125.0 million until the next redetermination date (which is scheduled to occur by October 2015).

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. 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. The Company was in compliance with all applicable covenants under the Revolving Credit Facility as of June 30, 2015 and December 31, 2014.

Note 8 Benefit Plans

Defined Contribution Plan

The Company currently maintains a retirement plan intended to provide benefits under section 401(K) of the Internal Revenue Code, under which employees are allowed to contribute portions of their compensation to a tax-qualified retirement account. Under the 401(K) plan, the Company provides matching contributions equal to 100% of the first 6% of employees eligible compensation contributed to the plan. The Company recognized expense of $0.3 million and $0.5 million for the three and six months ended June 30, 2015, respectively. The Company recognized expense of $0.1 million and $0.2 million for the three and six months ended June 30, 2014, respectively.

Defined Benefit Plan

The Company maintains a defined benefit plan covering certain employees of a previously acquired company. Benefits are based on the employees years of service and compensation. The following table details the components of pension benefit cost (in thousands):

	For the three months ended June 30,		For the six months ended June 30,	
	2015	**2014**	**2015**	**2014**
Service cost	$	$	$	$ 70

Interest cost	62	85	126	192
Expected return on plan assets	(82)	(112)	(164)	(224)
Amortization of transition obligation				70
Amortization of net (gain) loss	25	11	43	3
Settlement costs	96		96	
Net periodic benefit cost (benefit)	$ 101	$ (16)	$ 101	$ 111

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There were no employer contributions made during the three and six months ended June 30, 2015. As of March 31, 2014, benefit accruals in the plan were frozen resulting in a gain on reduction of pension obligations of $2.2 million for the six months ended June 30, 2014.

Note 9 Stock-Based Compensation

The Company is authorized to grant up to 16,000,000 shares of common stock under its 2014 Long-Term Incentive Plan (the Plan). The Plan allows stock-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent rights, qualified performance-based awards and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of the Company s Board of Directors. A total of 14,169,746 shares are available for future grant under the Plan as of June 30, 2015.

Our stock based compensation expense is as follows for the three and six months ended June 30, 2015 (in thousands):

	For the three months ended June 30,		For the six months ended June 30,	
	2015	2014	2015	2014
Restricted stock units	$ 748	$	$ 1,171	$
Performance units	376		528	
Restricted stock issued to directors	255		400	
Incentive units	31	27	58	56
Total expense	$ 1,410	$ 27	$ 2,157	$ 56

Restricted Stock Units

Restricted stock and restricted stock unit awards vest subject to the satisfaction of service requirements. The Company recognizes expense related to restricted stock and restricted stock unit awards on a straight-line basis over the requisite service period, which is three years. The grant date fair values of these awards are determined based on the closing price of the Company s common stock on the date of the grant. As of June 30, 2015, there was $6.5 million of total unrecognized compensation cost related to restricted stock units. A summary of restricted stock unit awards activity during the six months ended June 30, 2015 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total awarded and unvested, December 31, 2014		$	$
Granted	1,247,197	7.01	
Vested			
Forfeited	(39,210)	7.13	

Total awarded and unvested, June 30, 2015	1,207,987	$	6.78	$	6,354

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Performance Units

Performance unit awards vest subject to the satisfaction of a three-year service requirement and based on Total Shareholder Return (TSR), as compared to an industry peer group over that same period. The performance unit awards are measured at the grant date at fair value using a Monte Carlo valuation method. As of June 30, 2015, there was $3.8 million of total unrecognized compensation cost related to performance units. A summary of performance stock unit awards activity during the six months ended June 30, 2015 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands
Total awarded and unvested, December 31, 2014		$	$
Granted	469,368	8.77	
Vested			
Forfeited	(10,712)	8.77	
Total awarded and unvested, June 30, 2015	458,656	$ 8.77	$

The determination of the fair value of the performance unit awards noted above uses significant Level 3 assumptions in the fair value hierarchy including an estimate of the timing of forfeitures, the risk free rate and a volatility estimate tied to the Company s public peer group.

Restricted Stock Issued to Directors

On October 7, 2014, the Company issued an aggregate of 31,115 restricted shares of common stock to its seven non-employee members of its Board of Directors. For the six months ended June 30, 2015, the Company recognized expense of approximately $0.2 million related to these awards. These awards became fully vested on June 25, 2015.

On May 11, 2015, the Company issued an aggregate of 132,496 restricted shares of common stock to its seven non-employee members of its Board of Directors. For the six months ended June 30, 2015, the Company recognized expense of approximately $0.1 million related to these awards. As of June 30, 2015, there was $0.7 million of total unrecognized compensation cost related to restricted stock issued to Directors. These awards are scheduled to become fully vested on May 11, 2016.

Incentive Units

Eclipse Holdings has a total of 1,000 Class C-1 units and 1,000 Class C-2 units authorized to be issued to employees (Incentive Units). The Series C-1 and C-2 Incentive Units are non-voting with respect to partnership matters, and the holder thereof will begin to participate in distributions from Eclipse Holdings after distributions have been made to the holders of the Series A-1 and A-2 units that satisfy a specified hurdle rate and return on investment factor, with the level of participation in distributions adjusting upwards as distributions to the holders of the Series A-1 and A-2 units satisfy additional specified hurdle rates and return on investment factors.

Total compensation cost related to the Incentive Units was less than $0.1 million for each of the three months ended June 30, 2015 and 2014; and $0.1 million for each of the six months ended June 30, 2015 and 2014. As of June 30, 2015, there was $0.6 million of total unrecognized compensation cost related to Incentive Units, which is expected to be recognized over a weighted-average period of approximately 6 years.

The determination of the fair value of the incentive unit 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 Equity

Private Placement of Common Stock

On December 27, 2014, the Company entered into a Securities Purchase Agreement with private equity funds managed by EnCap Investments L.P., entities controlled by certain shareholders of the Company management team and certain other institutional investors pursuant to which the Company issued and sold to such purchasers an aggregate of 62,500,000 shares of common stock at a price of $7.04 per share pursuant to the exemptions from registration provided in Rule 506 of Regulation D promulgated under Section 4(2) of the Securities Act, such transaction referred to herein as the private placement.

On January 28, 2015, the Company closed the private placement and received net proceeds from the issuance of the shares to the purchasers of approximately $434 million (after deducting placement agent commissions and estimated expenses), which the Company intends to use to fund its capital expenditure plan and for general corporate purposes. Upon the closing of the private placement, the Company amended and restated the existing registration rights agreement that was entered into upon the closing of its initial public offering in order to provide the purchasers with certain registration rights with respect to the stock they purchased in the private placement.

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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 $0.1 million, which is the amount of the aggregate capital contributions made to Eclipse Operating by its members. As a result, Eclipse Operating became a wholly owned subsidiary of Eclipse I.

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 expenses are classified within *Operating expenses General and administrative* in the condensed consolidated statements of operations. The Company incurred expenses relating to the management fee of $15.6 million for the six months ended June 30, 2014.

During the three months ended June 30, 2015, the Company paid $0.6 million related to a final distribution of the assets of Eclipse Operating. This amount was distributed equally among the three former members of Eclipse Operating.

During the three and six months ended June 30, 2015, the Company incurred approximately $0.1 million and $0.2 million, respectively, related to flight charter services provided by BWH Air, LLC and BWH Air II, LLC, which are owned by the Company s Chairman, President and Chief Executive Officer. The fees are paid in accordance with a standard service contract that does not obligate the Company to any minimum terms.

Note 12 Commitments and Contingencies

(a) Legal Matters

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

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

In addition, many of the Company s other oil and gas leases in Ohio contain provisions identical or similar to those found in the challenged Oxford lease. As of August 14, 2015, we are a party to one other lawsuit that makes allegations similar to those made by the lessor in the *West* lawsuit. This lawsuit, together with the *West* case, affect approximately 157 gross (157 net) leasehold acres and were capitalized on our condensed consolidated balance sheet as of June 30, 2015 at $0.6 million.

The Company has undertaken efforts to amend the other leases acquired within the Utica Core Area in the Oxford Acquisition to address the issues raised by the trial court s ruling in the *West* case. These efforts have resulted in modifications to leases covering approximately 29,041 net acres out of the approximately 38,555 net acres. The Company s efforts 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 9,514 net acres to effectively resolve issues related to the West trial court s ruling or the amount of time and expense that will be required to amend these leases.

In light of the foregoing, if the appeals court affirms the trial court ruling in the West case, and if other courts in Ohio adopt a similar interpretation of the provisions in other oil and gas leases the Company acquired in the Oxford Acquisition, other lessors may challenge the validity of such leases and those challenged leases may be declared void. Consequently, this could result in a loss of the mineral rights and an impairment of the related assets which could have a material adverse impact on the Company s financial statements. These costs could potentially be impaired if it was determined that the West lawsuit leases are invalid. Other than this potential impairment, the Company is not able to estimate the range of other potential losses related to this matter.

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On September 26, 2014, the Ohio Court of Appeals for the Seventh Appellate District, the same appellate court that will decide the Company s appeal in the *West* case, issued its decision in the case of Clyde Hupp et al. v. Beck Energy Corporation, an appeal of a Monroe County trial court decision upon which the trial court in *West* based its decision. The appellate court held that while Ohio law disfavors perpetual leases, courts in Ohio have not found them to be per se illegal or void from their inception. The appellate court further held that the trial court misinterpreted both the pertinent lease provisions and Ohio law on the subject and erred in concluding that the Beck Energy lease is a no-term, perpetual lease that is void ab initio as against public policy. On November 7, 2014, the plaintiff landowners filed an appeal of the appellate court s decision with the Supreme Court of Ohio, which was accepted by the Supreme Court of Ohio on January 28, 2015. On March 2, 2015, the Ohio Court of Appeals for the Seventh Appellate District stayed all proceedings in the Company s appeal in the *West* case pending a decision by the Supreme Court of Ohio in the *Hupp v. Beck Energy* appeal.

The Company believes that there are strong grounds for appeal of the *West* decision, and therefore, the Company intends to pursue all available appellate rights, and to vigorously defend against the claims in this lawsuit. Based on the merits of the Company s appeal and the favorable holdings in the *Hupp v. Beck Energy* appellate decision described above, the Company believes that it is not probable that the trial court s decision in West will be upheld in the appeal or that the Company will incur a material loss in the lawsuit. The Company has not recorded an accrual for the potential losses attributable to this lawsuit.

Other Matters

From time to time, the Company may be a party to legal proceedings arising in the ordinary course of business. Management does not believe that a material loss is probable as a result of such proceedings.

(b) Environmental Matters

The Company is subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs to the oil and natural gas industry in general, the business and prospects of the Company could be adversely affected.

(c) Leases

The development of the Company s oil and natural gas properties under their related leases will require a significant amount of capital. The timing of those expenditures will be determined by the lease provisions, the term of the lease and other factors associated with unproved leasehold acreage. To the extent that the Company is not the operator of oil and natural gas properties that it owns an interest in, the timing, and to some degree the amount, of capital expenditures will be controlled by the operator of such properties.

The Company leases office space under operating leases that expire between the years 2015 to 2025. The Company recognized rent expense of $0.2 million and $0.1 million for the three months ended June 30, 2015 and 2014, respectively, and rent expense of $0.4 million and $0.1 million for the six months ended June 30, 2015 and 2014, respectively.

Note 13 Income Tax

For 2015, the Company s annual estimated effective tax rate is forecasted to be a benefit of 30.83%, exclusive of discrete items. The Company expects to incur both a book and tax loss in fiscal year 2015, and thus, no current federal income taxes are anticipated to be paid. We compute our quarterly taxes under the effective tax rate method based on applying an anticipated annual effective tax rate to our year-to-date income, except for discrete items. Income taxes for discrete items are computed and recorded in the period that the specific transaction occurs. For the quarter ended June 30, 2015, our overall effective tax rate on operations was different than the federal statutory rate of 35% due primarily to state income taxes, valuation allowances and other permanent differences. In forecasting the 2015 annual estimated effective tax rate, management believes that it should limit any tax benefit suggested by the tax effect of the forecasted book loss such that no net deferred tax asset is recorded in 2015. Management reached this conclusion considering several factors such as: (i) the Company s short tax history, (ii) the lack of carryback potential resulting in a tax refund, and (iii) in light of current commodity pricing uncertainty, there is insufficient external evidence to suggest that net tax attribute carryforwards are collectible beyond offsetting existing deferred tax liabilities inherent in our balance sheet (which are primarily related to the excess of book carrying value of properties over their respective tax bases). At this time, the estimated valuation allowance to be recorded in 2015 (there was no valuation allowance recorded during 2014) would be $9.7 million.

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Note 14 Subsequent Events

The Company redeemed all of the outstanding Senior PIK Notes on July 13, 2015 for approximately $510.7 million, including outstanding principal balance, a make-whole premium and accrued interest. (See Note 7 *Debt*). Management has evaluated subsequent events and believes there are no other events that would have a material impact on the aforementioned financial statements and related disclosures.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our Annual Report on Form 10-K for the year ended December 31, 2014 and our condensed 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. We do not undertake any obligation to publicly update any forward-looking statements except as otherwise required by applicable law.

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 101,000 of our net acres are located in the Utica Shale fairway, which we refer to as the Utica Core Area, and approximately 27,000 of these net acres are also prospective for the highly liquids rich area of the Marcellus Shale in Eastern Ohio within what we refer to as Our Marcellus Project Area. We are the operator of approximately 87% of our net acreage within the Utica Core Area and Our Marcellus Project Area.

As of June 30, 2015, we, or our operating partners, had commenced drilling 201 gross wells within the Utica Core Area and Our Marcellus Project Area, of which 13 gross were drilling, 31 gross were awaiting completion or were in the process of being completed, 23 gross were awaiting midstream, and 134 gross had been turned to sales.

As of June 30, 2015, we were operating 1 horizontal rig in the Utica Core Area. We had average daily production for the three months ended June 30, 2015 of approximately 198.6 MMcfe comprised of approximately 57% natural gas, 23% NGLs and 20% oil.

How We Evaluate Our Operations

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

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

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

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Overview of the Three Months Ended June 30, 2015 Results

Operationally, our performance during the three months ended June 30, 2015 reflects continued development of our acreage. During the three months ended June 30, 2015, we achieved the following financial and operating results:

- increased our average daily net production for the three months ended June 30, 2015 by 374% over the comparable period of the prior year, to 198.6 MMcfe per day;
- commenced drilling 4 gross operated Utica Shale wells, completed 7 gross operated Utica Shale wells and turned-to-sales 3 gross operated wells during the three months ended June 30, 2015;
- participated in 4 gross non-operated Utica Shale wells, completed 8 gross non-operated Utica Shale wells and turned-to-sales 16 gross non-operated Utica Shale wells during the three months ended June 30, 2015;
- recognized a net loss of $42.0 million for the three months ended June 30, 2015 compared to $112.6 million for the three months ended June 30, 2014; and
- realized Adjusted EBITDAX of $31.5 million for the three months ended June 30, 2015 compared to $11.3 million for the three months ended June 30, 2014. Adjusted EBITDAX is a non-GAAP financial measure. See *Non-GAAP Financial Measure* for more information.

Overview of the Six Months Ended June 30, 2015 Results

Operationally, our performance during the six months ended June 30, 2015 reflects continued development of our acreage. During the six months ended June 30, 2015, we achieved the following financial and operating results:

- increased our average daily net production for the six months ended June 30, 2015 by 346% over the comparable period of the prior year, to 179.2 MMcfe per day;
- commenced drilling 8 gross operated Utica Shale wells, completed 9 gross operated Utica Shale wells and turned-to-sales 14 gross operated wells during the six months ended June 30, 2015;
- participated in 10 gross non-operated Utica Shale wells, completed 25 gross non-operated Utica Shale wells and turned-to-sales 25 gross non-operated wells during the six months ended June 30, 2015;
- recognized a net loss of $76.1 million for the six months ended June 30, 2015 compared to $131.1 million for the six months ended June 30, 2014; and

realized Adjusted EBITDAX of $52.2 million for the six months ended June 30, 2015 compared to $23.3 million for the six months ended June 30, 2014. Adjusted EBITDAX is a non-GAAP financial measure. See *Non-GAAP Financial Measure* for more information.

Market Conditions

The following table lists average, high and low NYMEX Henry Hub prices for natural gas and NYMEX WTI prices for oil for the three and six months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
NYMEX Henry Hub High ($/MMBtu)	$ 3.04	$ 4.83	$ 3.32	$ 6.15
NYMEX Henry Hub Low ($/MMBtu)	2.50	4.28	2.50	4.01
Average NYMEX Henry Hub ($/MMBtu)	2.74	4.58	2.81	4.65
NYMEX WTI High ($/Bbl)	$ 61.36	$ 107.26	$ 61.36	$ 107.26
NYMEX WTI Low ($/Bbl)	49.13	99.42	43.39	91.66
Average NYMEX WTI ($/Bbl)	57.67	102.99	53.19	100.84

Historically, commodity prices have been extremely volatile, and we expect this volatility to continue for the foreseeable future. A further or extended decline in commodity prices could materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. We make price assumptions that are used for planning purposes, and a significant portion of our cash outlays, including rent, salaries and noncancelable capital commitments, are largely fixed in nature. Accordingly, if commodity prices are below the expectations on which these commitments were based, our financial results are likely to be adversely and disproportionately affected because these cash outlays are not variable in the short term and cannot be quickly reduced to respond to unanticipated decreases in commodity prices.

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Significant or extended price declines could also adversely affect the amount of oil, NGLs and natural gas that we can produce economically, which may result in our having to make significant downward adjustments to our estimated proved undeveloped reserves. A reduction in production could also result in a shortfall in expected cash flows and require us to reduce capital spending or raise funds to cover any such shortfall. Any of these factors could negatively affect our ability to replace production and our future rate of growth or dilute existing shareholders.

Commodity price revisions, based on 12-month average SEC prices for 2014, did not have a significant impact on our 2014 reserve revisions, but could potentially have a significant impact on future reserve estimates if the currently depressed pricing environment for oil, NGLs and natural gas persists or worsens. From December 31, 2014 to June 30, 2015, the 12-month average SEC price for WTI oil declined from $94.99 per Bbl to $71.68 per Bbl, while the 12-month average SEC price for Henry Hub natural gas declined from $4.35 per MMBtu to $3.39 per MMBtu. Service costs have also declined significantly during the same time period, which should mitigate a portion of the negative impact of declining commodity prices on our future reserve estimates. In addition, we expect to continue to increase our proved reserves through further extensions and discoveries as we continue to develop our acreage position.

Based on the current market conditions, we have revised our capital budget for 2015 downward to $352 million, which is a 45% reduction from our initial capital budget for the year, and a 57% decrease from 2014. We have reduced the number of our operated horizontal drilling rigs down to one, compared to three horizontal rigs as of December 31, 2014. As a result of the reduction in drilling activity, we recorded a charge related to the early termination of drilling rig contracts of $0.4 and $7.4 million during the three months and six months ended June 30, 2015, respectively. In addition, this reduction in planned capital expenditures will likely result in a slower rate of growth of our proved reserves through extensions and discoveries than previously forecasted as development of our acreage position is deferred to subsequent years. See additional details related to our capital expenditures in *Capital Requirements* .

Based on the reassessment of our capital expenditure plan and the current commodity pricing environment, we have shifted our drilling activity to the dry gas area of our Utica Shale acreage due to greater potential returns of this area. The dry gas area of our Utica Shale acreage has more readily available access to transportation infrastructure and a larger number of our units in the area are ready for drilling as compared to our other operating areas. We currently expect to resume our development activity in the wet gas areas of our Utica Shale acreage and in our Marcellus acreage during 2017.

We consider future commodity prices when determining our development plan but many other factors are also considered. Although the magnitude of change in these collective factors within a sustained low commodity price environment is difficult to estimate, we currently expect to execute our development plan based on current conditions. To the extent there is a significant increase or decrease in commodity prices in the future, we will assess the impact on our development plan at that time, and we may respond to such changes by altering our capital budget or our development plan. We plan to fund our development budget with a portion of the proceeds from the issuance of our 8.875% Senior Notes due 2023, the proceeds remaining from the private placement of our common stock that we completed during January 2015, cash flows from operations, borrowings under our revolving credit facility, proceeds from asset sales, and proceeds from additional debt and/or equity offerings.

Results of Operations

Three Months Ended June 30, 2015 Compared to Three Months Ended June 30, 2014

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, 2015 and 2014:

	Three Months Ended June 30, 2015	2014	Change
Revenues (in thousands):			
Natural gas sales	$ 28,175	$ 10,066	$ 18,109
NGLs sales	9,563	6,329	3,234
Oil sales	27,246	10,560	16,686
Total revenues	$ 64,984	$ 26,955	$ 38,029

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Our production grew by approximately 14.3 Bcfe for the three months ended June 30, 2015 over the same period in 2014, as we placed new wells into production, partially offset by natural decline. Our production for the three months ended June 30, 2015 and 2014 is set forth in the following table:

	Three Months Ended June 30,		
	2015	2014	Change
Production:			
Natural gas (MMcf)	10,385.9	2,458.8	7,927.1
NGLs (Mbbls)	682.7	113.1	569.6
Oil (Mbbls)	599.1	113.2	485.9
Total (MMcfe)	18,076.5	3,816.6	14,259.9
Average daily production volume:			
Natural gas (Mcf/d)	114,131	27,020	87,111
NGLs (Bbls/d)	7,502	1,243	6,259
Oil (Bbls/d)	6,584	1,244	5,340
Total (Mcfe/d)	198,643	41,941	156,702

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Our average realized price (including cash derivative settlements and firm third-party transportation costs) received during the second quarter 2015 was $3.82 per Mcfe compared to $6.82 per Mcfe in the second quarter 2014. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales prices (excluding cash settled derivatives) does not include derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying condensed consolidated statements of operations. Average sales prices (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the three months ended June 30, 2015 and 2014 are shown below:

	For the Three Months Ended June 30,		
	2015	**2014**	**Change**
Average Sales Price (excluding cash settled derivatives)			
Natural gas ($/Mcf)	$ 2.71	$ 4.09	$ (1.38)
NGLs ($/Bbl)	14.01	55.95	(41.94)
Oil ($/Bbl)	45.48	93.30	(47.82)
Total average prices ($/Mcfe)	3.59	7.06	(3.47)
Average Sales Price (including cash settled derivatives)			
Natural gas ($/Mcf)	$ 3.46	$ 3.71	$ (0.25)
NGLs ($/Bbl)	14.01	55.95	(41.94)
Oil ($/Bbl)	46.64	93.30	(46.66)
Total average prices ($/Mcfe)	4.06	6.82	(2.76)
Average Sales Price (including firm transportation)			
Natural gas ($/Mcf)	$ 2.30	$ 4.09	$ (1.79)
NGLs ($/Bbl)	14.01	55.95	(41.94)
Oil ($/Bbl)	45.48	93.30	(47.82)
Total average prices ($/Mcfe)	3.35	7.06	(3.71)
Average Sales Price (including cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$ 3.05	$ 3.71	$ (0.66)
NGLs ($/Bbl)	14.01	55.95	(41.94)
Oil ($/Bbl)	46.64	93.30	(46.66)
Total average prices ($/Mcfe)	3.82	6.82	(3.00)

Brokered natural gas and marketing revenue was $9.5 million for the three months ended June 30, 2015. The Company did not have any brokered natural gas and marketing revenue for the three months ended June 30, 2014. Brokered natural gas and marketing revenue includes revenue received from selling natural gas not related to production and from the release of firm transportation capacity.

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Costs and Expenses

We believe some of our expense fluctuations are most accurately 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, 2015 and 2014:

	Three Months Ended June 30,		
	2015	2014	Change
Operating expenses (in thousands):			
Lease operating	$ 3,589	$ 2,643	$ 946
Transportation, gathering and compression	22,634	2,949	19,685
Production and ad valorem taxes	3,078	702	2,376
Depreciation, depletion and amortization	60,641	9,957	50,684
General and administrative	12,717	8,429	4,288
Rig termination	366		366
Operating expenses per Mcfe:			
Lease operating	$ 0.20	$ 0.69	$ (0.49)
Transportation, gathering and compression	1.25	0.77	0.48
Production, severance and ad valorem taxes	0.17	0.18	(0.01)
Depreciation, depletion and amortization	3.35	2.61	0.74
General and administrative	0.70	2.21	(1.51)
Rig termination	0.02		0.02

Lease operating expense was $3.6 million in the three months ended June 30, 2015 compared to $2.6 million in the three months ended June 30, 2014. The increase of $1.0 million is attributable to an increase in the number of producing wells during the three months ended June 30, 2015, as compared to the three months ended June 30, 2014. Lease operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties.

Transportation, gathering and compression expense was $22.6 million during the three months ended June 30, 2015 compared to $2.9 million in the three months ended June 30, 2014. These third party costs were higher in the three months ended June 30, 2015 due to our production growth where we have third party gathering and compression agreements and increased processing costs associated with our higher liquids production. The following table details our transportation, gathering and compression expenses for the three months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		
	2015	2014	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	$ 7,630	$ 1,708	$ 5,922
Processing and fractionation	7,373	1,152	6,221
Liquids transportation and stabilization	2,681	7	2,674
Marketing	569	73	496
Firm transportation	4,381	9	4,372

	$ 22,634	$ 2,949	$ 19,685

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $3.1 million in the three months ended June 30, 2015 compared to $0.7 million in the three months ended June 30, 2014. Production and ad valorem taxes increased from the three months ended June 30, 2014 to the three months ended June 30, 2015 due to an increase in production volumes subject to production taxes.

Depreciation, depletion and amortization was approximately $60.6 million in the three months ended June 30, 2015 compared to $10.0 million in the three months ended June 30, 2014. The increase in the three months ended June 30, 2015 when compared to the three months ended June 30, 2014 is due to the increase in production during the three months ended June 30, 2015. On a per Mcfe basis, DD&A increased to $3.35 in the three months ended June 30, 2015 from $2.61 in the three months ended June 30, 2014, which was predominantly driven by a higher depletion rate. The increase in depletion rate during the three months ended June 30, 2015 was due to total proved reserves (the denominator) increasing at a lower rate than production (the numerator) over the period.

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General and administrative expense was $12.7 million for the three months ended June 30, 2015 compared to $8.4 million for the three months ended June 30, 2014. The increase of $4.3 million during the three months ended June 30, 2015 when compared to three months ended June 30, 2014 was primarily due to higher salaries and benefits associated with increased headcount as of June 30, 2015 as compared to June 30, 2014.

Rig termination expense was $0.4 million for the three months ended June 30, 2015 resulting from the early termination of drilling contracts during the three months ended June 30, 2015. There were no rig termination costs for the three months ended June 30, 2014.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include exploration expense including impairment charges, accretion of asset retirement obligation expense, gain on sale of assets and brokered natural gas and marketing expense. The following table details our other operating expenses for the three months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		
	2015	2014	Change
Other Operating Expenses (in thousands):			
Brokered natural gas and marketing expense	$ 10,795	$	$ 10,795
Exploration	6,243	9,295	(3,052)
Accretion of asset retirement obligations	399	191	208
Gain on sale of assets	(5,553)		(5,553)

Brokered natural gas and marketing expense was $10.8 million for the three months ended June 30, 2015. The Company did not have any brokered natural gas and marketing expense for the three months ended June 30, 2014. Brokered natural gas and marketing expenses relate to gas purchases that we buy and sell not relating to production and firm transportation capacity that is marketed to third parties.

Exploration expense decreased to $6.2 million in the three months ended June 30, 2015 compared to $9.3 million in the three months ended June 30, 2014. The decrease was primarily due to lower delay rental payments. The following table details our exploration-related expenses for the three months ended June 30, 2015 and 2014:

	Three Months Ended June 30,		
	2015	2014	Change
Exploration Expenses (in thousands):			
Geological and geophysical	$ 15	$ 290	$ (275)
Delay rentals	1,784	5,237	(3,453)
Impairment of unproved properties	4,420	3,666	754
Dry hole	24	102	(78)
	$ 6,243	$ 9,295	$ (3,052)

Impairment of unproved properties was $4.4 million for the three months ended June 30, 2015 compared to $3.7 million for the three months ended June 30, 2014. We assess individually significant unproved properties for impairment and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors, including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

Accretion of asset retirement obligations was $0.4 million in the three months ended June 30, 2015, compared to $0.2 million in three months ended June 30, 2014. The increase in accretion expense primarily relates to the increase in the asset retirement obligations associated with the increase in the number of producing wells in the three months ending June 30, 2015.

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Gain on sale of assets was $5.6 million in the three months ended June 30, 2015, compared to $0 in the three months ended June 30, 2014. The increase in the gain on sale of assets is related to the sale of a central processing facility and certain pipelines during the three months ended June 30, 2015.

Other Income (Expense)

Gain (loss) on derivative instruments was ($3.5) million for the three months ended June 30, 2015 compared to ($0.9) million for the three months ended June 30, 2014. Cash receipts (payments) were approximately $8.5 million and ($0.8) million for derivative instruments that settled during the three months ended June 30, 2015 and June 30, 2014, respectively.

Interest expense, net was $14.4 million for the three months ended June 30, 2015 compared to $11.6 million for three months ended June 30, 2014. The increase in interest expense was due to the increase in the principal balance of our Senior PIK Notes.

Income tax benefit (expense) was $16.4 million for the three months ended June 30, 2015 compared to income tax expense of ($94.5) million for the three months ended June 30, 2014. The income tax benefit for the three months ended June 30, 2015 was due to pre-tax loss incurred during the three months ended June 30, 2015. The income tax expense for the three months ended June 30, 2014 was primarily related to a charge to record the initial impact of the change in our tax status as a result of the corporate reorganization.

Six months Ended June 30, 2015 Compared to Six months Ended June 30, 2014

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, 2015 and 2014:

	Six Months Ended June 30,		
	2015	**2014**	**Change**
Revenues (in thousands):			
Natural gas sales	$ 54,584	$ 24,025	$ 30,559
NGLs sales	17,127	6,904	10,223
Oil sales	39,887	20,814	19,073
Total revenues	$ 111,598	$ 51,743	$ 59,855

Our production grew by approximately 25.2 Bcfe for the six months ended June 30, 2015 over the same period in 2014, as we placed new wells into production, partially offset by natural decline. Our production for the six months ended June 30, 2015 and 2014 is set forth in the following table:

	Six Months Ended June 30,		
	2015	**2014**	**Change**
Production:			

Natural gas (MMcf)	20,251.2	5,205.5	15,045.7
NGLs (Mbbls)	1,077.2	122.4	954.8
Oil (Mbbls)	953.6	221.0	732.6
Total (MMcfe)	32,436.0	7,265.9	25,170.1
Average daily production volume:			
Natural gas (Mcf/d)	111,885	28,760	83,125
NGLs (Bbls/d)	5,951	676	5,275
Oil (Bbls/d)	5,269	1,221	4,048
Total (Mcfe/d)	179,204	40,143	139,061

Our average realized price (including all derivative settlements and third-party firm transportation costs) received during the six months ended June 30, 2015 was $3.73 per Mcfe compared to $6.77 per Mcfe in the six months ended June 30, 2014. Because we record transportation costs on two separate bases, as required by U.S. GAAP, we believe computed final realized prices of production volumes should include the total impact of firm transportation expense. Our average realized price (including all derivative settlements and third-party firm transportation costs) calculation also includes all cash settlements for derivatives. Average sales prices (excluding cash settled derivatives) does not include derivative settlements or third party transportation costs which are reported in transportation, gathering and compression expense on the accompanying condensed consolidated statements of operations. Average sales prices (excluding cash settled derivatives) does include transportation costs where we receive net revenue proceeds from purchasers. Average realized price calculations for the six months ended June 30, 2015 and 2014 are shown below:

	For the Six Months Ended June 30,		
	2015	2014	Change
Average Sales Price (excluding cash settled derivatives)			
Natural gas ($/Mcf)	$ 2.70	$ 4.62	$ (1.92)
NGLs ($/Bbl)	15.90	56.41	(40.51)
Oil ($/Bbl)	41.83	94.19	(52.36)
Total average prices ($/Mcfe)	3.44	7.12	(3.68)
Average Sales Price (including cash settled derivatives)			
Natural gas ($/Mcf)	$ 3.37	$ 4.16	$ (0.79)
NGLs ($/Bbl)	15.90	56.41	(40.51)
Oil ($/Bbl)	42.56	94.19	(51.63)
Total average prices ($/Mcfe)	3.89	6.79	(2.90)
Average Sales Price (including firm transportation)			
Natural gas ($/Mcf)	$ 2.44	$ 4.59	$ (2.15)
NGLs ($/Bbl)	15.90	56.41	(40.51)
Oil ($/Bbl)	41.83	94.19	(52.36)
Total average prices ($/Mcfe)	3.28	7.10	(3.82)
Average Sales Price (including cash settled derivatives and firm transportation)			
Natural gas ($/Mcf)	$ 3.12	$ 4.13	$ (1.01)
NGLs ($/Bbl)	15.90	56.41	(40.51)
Oil ($/Bbl)	42.56	94.19	(51.63)
Total average prices ($/Mcfe)	3.73	6.77	(3.04)

Brokered natural gas and marketing revenue was $6.7 million for the six months ended June 30, 2015. The Company did not have any brokered natural gas and marketing revenue for the six months ended June 30, 2014. Brokered natural gas and marketing revenue includes revenue received from selling natural gas not related to production and from the release of firm transportation capacity.

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Costs and Expenses

We believe some of our expense fluctuations are most accurately 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, 2015 and 2014:

	Six Months Ended June 30,		
	2015	2014	Change
Operating expenses (in thousands):			
Lease operating	$ 6,935	$ 4,434	$ 2,501
Transportation, gathering and compression	35,085	3,853	31,232
Production and ad valorem taxes	5,178	1,055	4,123
Depreciation, depletion and amortization	103,073	21,984	81,089
General and administrative	24,660	16,823	7,837
Rig termination	7,423		7,423
Operating expenses per Mcfe:			
Lease operating	$ 0.21	$ 0.61	$ (0.40)
Transportation, gathering and compression	1.08	0.53	0.55
Production, severance and ad valorem taxes	0.16	0.15	0.01
Depreciation, depletion and amortization	3.18	3.03	0.15
General and administrative	0.76	2.32	(1.56)
Rig termination	0.22		0.22

Lease operating expense was $6.9 million in the six months ended June 30, 2015 compared to $4.4 million in the six months ended June 30, 2014. The increase of $2.5 million is attributable to an increase in the number of producing wells during the six months ended June 30, 2015, as compared to the six months ended June 30, 2014. Lease operating expenses include normally recurring expenses to operate and produce our wells, non-recurring workovers and repairs. We experience increases in operating expenses as we add new wells and manage existing properties.

Transportation, gathering and compression expense was $35.1 million during the six months ended June 30, 2015 compared to $3.9 million in the six months ended June 30, 2014. These third party costs were higher in the six months ended June 30, 2015 due to our production growth where we have third party gathering and compression agreements and increased processing costs associated with our higher liquids production. The following table details our transportation, gathering and compression expenses for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30,		
	2015	2014	Change
Transportation, gathering and compression (in thousands):			
Gathering, compression and fuel	$ 10,868	$ 2,308	$ 8,560
Processing and fractionation	13,446	1,159	12,287
Liquids transportation and stabilization	4,537	145	4,392
Marketing	1,115	92	1,023
Firm transportation	5,119	149	4,970

	$ 35,085	$ 3,853	$ 31,232

Production and ad valorem taxes are paid based on market prices and applicable tax rates. Production and ad valorem taxes were $5.2 million in the six months ended June 30, 2015 compared to $1.1 million in the six months ended June 30, 2014. Production and ad valorem taxes increased from the six months ended June 30, 2014 to the six months ended June 30, 2015 due to an increase in production volumes subject to production taxes.

Depreciation, depletion and amortization was approximately $103.1 million in the six months ended June 30, 2015 compared to $22.0 million in the six months ended June 30, 2014. The increase in the six months ended June 30, 2015 when compared to the six months ended June 30, 2014 is due to the increase in production during the six months ended June 30, 2015. On a per Mcfe basis, DD&A increased to $3.18 in the six months ended June 30, 2015 from $3.03 in the six months ended June 30, 2014, which was predominantly driven by a higher depletion rate. The increase in depletion rate during the six months ended June 30, 2015 was due to total proved reserves (the denominator) increasing at a lower rate than production (the numerator) over the period.

General and administrative expense was $24.7 million for the six months ended June 30, 2015 compared to $16.8 million for the six months ended June 30, 2014. The increase of $7.9 million during the six months ended June 30, 2015 when compared to the six months ended June 30, 2014 is primarily due to higher salaries and benefits associated with increased headcount as of June 30, 2015 as compared to June 30, 2014.

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Rig termination expense was $7.4 million for the six months ended June 30, 2015 resulting from the early termination of drilling contracts during the six months ended June 30, 2015. There were no rig termination costs for the six months ended June 30, 2014.

Other Operating Expenses

Our total operating expenses also include other expenses that generally do not trend with production. These expenses include exploration expense including impairment charges, accretion of asset retirement obligation expense, gain on sale of assets, brokered natural gas and marketing expense and gain on reduction of pension obligations. The following table details our other operating expenses for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30, 2015	2014	Change
Other Operating Expenses (in thousands):			
Brokered natural gas and marketing expense	$ 10,795	$	$ 10,795
Exploration	19,696	13,840	5,856
Accretion of asset retirement obligations	785	377	408
Gain on sale of assets	(5,473)		(5,473)
Gain on reduction of pension obligations		(2,208)	2,208

Brokered natural gas and marketing expense was $10.8 million for the six months ended June 30, 2015. The Company did not have any brokered natural gas and marketing expense for the six months ended June 30, 2014. Brokered natural gas and marketing expenses relate to gas purchases that we buy and sell not relating to production and firm transportation capacity that is marketed to third parties in excess of production volumes.

Exploration expense increased to $19.7 million in the six months ended June 30, 2015 compared to $13.8 million in the six months ended June 30, 2014. The increase was primarily due to lease expirations costs and delay rental payments. The following table details our exploration-related expenses for the six months ended June 30, 2015 and 2014:

	Six Months Ended June 30, 2015	2014	Change
Exploration Expenses (in thousands):			
Geological and geophysical	$ 131	$ 359	$ (228)
Delay rentals	13,492	9,686	3,806
Impairment of unproved properties	6,044	3,666	2,378
Dry hole	29	129	(100)
	$ 19,696	$ 13,840	$ 5,856

Impairment of unproved properties was $6.0 million for the six months ended June 30, 2015 compared to $3.7 million for the six months ended June 30, 2014. We assess individually significant unproved properties for impairment and recognize a loss where circumstances indicate impairment in value. In determining whether a significant unproved property is impaired we consider numerous factors, including, but not limited to, current exploration plans, favorable or unfavorable activity on the property being evaluated and/or adjacent properties, our geologists evaluation of the property and the remaining months in the lease term for the property. Impairment of individually insignificant unproved properties is assessed and amortized on an aggregate basis based on our average holding period, expected forfeiture rate and anticipated drilling success. As we continue to review our acreage positions and high grade our drilling inventory based on the current price environment, additional leasehold impairments and abandonments may be recorded.

Accretion of asset retirement obligations was $0.8 million in the six months ended June 30, 2015, compared to $0.4 million in six months ended June 30, 2014. The increase in accretion expense primarily relates to the increase in the asset retirement obligations associated with the increase in the number of producing wells in the six months ended June 30, 2015.

Gain on sale of assets was $5.5 million in the six months ended June 30, 2015, compared to $0 in the six months ended June 30, 2014. The increase in the gain on sale of assets is related to the sale of a central processing facility and certain pipelines during the three months ended June 30, 2015.

Gain on reduction of pension obligations was $2.2 million in the six months ended June 30, 2014. Effective June 30, 2014, we froze the benefit accruals related to the defined benefit pension plan assumed in the Oxford Acquisition, which was completed during fiscal 2013. The Company did not have a gain on reduction of pension obligations for the six months ended June 30, 2015.

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Other Income (Expense)

Gain (loss) on derivative instruments was $7.8 million for the six months ended June 30, 2015 compared to a loss of ($4.5) million for the six months ended June 30, 2014. Cash receipts (payments) were approximately $14.4 million and ($2.2) million for derivative instruments that settled during the six months ended June 30, 2015 and June 30, 2014, respectively.

Interest expense, net was $28.4 million for the six months ended June 30, 2015 compared to $25.3 million for six months ended June 30, 2014. The increase in interest expense was due to the increase in the principal balance of our Senior PIK Notes.

Income tax benefit (expense) was $34.0 million for the six months ended June 30, 2015 compared to income tax expense of ($94.5) million for the six months ended June 30, 2014. The income tax benefit for the six months ended June 30, 2015 was due to pre-tax loss incurred during the six months ended June 30, 2015. The income tax expense for the six months ended June 30, 2014 was 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, borrowings under our Revolving Credit Facility and proceeds from issuances of debt and equity securities.

Six Months Ended June 30, 2015 Compared to the Six Months Ended June 30, 2014

Net cash provided by (used in) operations in the six months ended June 30, 2015 was $49.5 million compared to ($16.1) million in the six months ended June 30, 2014. The increase in cash provided from operating activities reflects an increase in production, partially offset by higher operating costs. Net cash provided from operations is also affected by working capital changes and the timing of cash receipts and disbursements.

Net cash used in investing activities in the six months ended June 30, 2015 was $291.9 million compared to $268.9 million in the six months ended June 30, 2014.

During the six months ended June 30, 2015, we:

- spent $327.9 million on capital expenditures for oil and natural gas properties;
- spent $1.3 million on property and equipment; and
- received $37.3 million of proceeds relating to the sale of gathering facilities and equipment.

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

- spent $269.7 million on capital expenditures; and
- received $0.8 million related to the acquisition of Eclipse Operating.

Net cash provided by financing activities in the six months ended June 30, 2015 decreased to $432.4 million compared to $668.9 million in the six months ended June 30, 2014.

During the six months ended June 30, 2015, we:

- issued shares of common stock in a private placement transaction for proceeds to us totaling approximately $434.2 million, net of $5.7 million of issuance costs.

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.

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Liquidity and Capital Resources

Our main sources of liquidity and capital resources are internally generated cash flow from operations, asset sales, borrowings under our Revolving Credit Facility 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. We periodically review capital expenditures and adjust our budget based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Future success in growing reserves and production will be highly dependent on capital resources available and the success of finding or acquiring additional reserves. We will continue using net cash on hand, cash flows from operations and proceeds available under our Revolving Credit Facility to satisfy near-term financial obligations and liquidity needs, and as necessary, we will seek additional sources of debt or equity to fund these requirements. Longer-term cash flows are subject to a number of variables including the level of production and prices we receive for our production as well as various economic conditions that have historically affected the natural gas and oil business. Our ability to expand our reserve base is, in part, dependent on obtaining sufficient capital through internal cash flow, bank borrowings, asset sales or the issuance of debt or equity securities. There can be no assurance that internal cash flow and other capital sources will provide sufficient funds to maintain capital expenditures that we believe are necessary to offset inherent declines in production and proven reserves.

Credit Arrangements

Long-term debt at June 30, 2015, excluding discount, totaled $437.3 million and at December 31, 2014 totaled $422.5 million, consisting of our Senior PIK Notes. The Company redeemed all of the outstanding Senior PIK Notes on July 13, 2015 for approximately $510.7 million, including outstanding principal balance, a make-whole premium and accrued interest. (See Note 7 *Debt*).

The Indenture governing our Senior PIK Notes imposed limitations on the payment of dividends and other restricted payments (as defined in the Indenture). The Indenture also contains customary covenants relating to debt incurrence, working capital, dividends and financial ratios. We were in compliance with all covenants at June 30, 2015 and December 31, 2014.

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

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior notes due 2023 (the Notes) at an issue price of 97.903% of the principal amount of the Notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the Notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S under the Securities Act. Upon closing, we received proceeds of approximately $525.5 million, after deducting original issue discount, the initial purchasers discounts and estimated offering expenses, of which we used approximately $510.7 million to finance the redemption of all of our outstanding 12.0% Senior PIK notes due 2018. We intend to use the remaining net proceeds to fund our capital expenditure plan and for general corporate purposes. (See Note 7 *Debt*).

In February 2014, we entered into our $500 million Revolving Credit Facility which was amended and restated on January 12, 2015, and which matures on January 15, 2018 and includes customary affirmative and negative covenants. As of December 31, 2014, the borrowing base was $100 million and we had no outstanding borrowings. In March 2015, we had a redetermination of the borrowing base under the Revolving Credit Facility, which increased the borrowing base to $125 million. After giving effect to our outstanding letters of credit issued, totaling $27.8 million, we had available borrowing capacity under our Revolving Credit Facility of $97.2 million at June 30, 2015. The borrowing base under our Revolving Credit Facility is scheduled to be redetermined semi-annually (in April and October).

The Revolving Credit Facility was further amended and restated on June 11, 2015 and became effective upon the issuance of the Notes. Among other things, pursuant to the Amended Credit Agreement, the Company assumed all of the rights and obligations of Eclipse I as the borrower under the Existing Credit Agreement. Furthermore, the Amended Credit Agreement allowed for the issuance of the Notes and provided that the Company would not incur an immediate reduction in borrowing base under its Revolving Credit Facility as a result of the issuance of the Notes. Accordingly, the borrowing base under the Company s revolving credit facility immediately following the issuance of the Notes remained at $125.0 million until the next redetermination date (which is scheduled to occur by October 2015).

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Commodity Hedging Activities

Our primary market risk exposure is in the prices we receive for our natural gas, NGLs and oil production. Realized pricing is primarily driven by the spot regional market prices applicable to our U.S. natural gas, NGLs and oil production. Pricing for natural gas, NGLs and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

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

Our hedging activities are intended to support natural gas, NGLs and oil prices at targeted levels and to manage our exposure to price fluctuations. The counterparty is required to make a payment to us for the difference between the floor price specified in the contract and the settlement price, which is based on market prices on the settlement date, if the settlement price is below the floor price. We are required to make a payment to the counterparty for the difference between the ceiling price and the settlement price if the ceiling price is below the settlement price. These contracts may include price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, zero cost collars that set a floor and ceiling price for the hedged production, and puts which require us to pay a premium either up front or at settlement and allow us to receive a fixed price at our option if the put price is above the market price. As of June 30, 2015, we had entered into the following derivative contracts:

Natural Gas Derivatives

Description	Volume (MMBtu/d)	Production Period		Weighted Average Price ($/MMBtu)	
Natural Gas Swaps:					
	62,500	July 2015	December 2015	$	3.78
	25,000	January 2016	December 2016	$	3.66
	7,000	July 2015	October 2015	$	2.84
Natural Gas Three-way Collar:					
Floor purchase price (put)	15,000	July 2015	December 2015	$	3.60
Ceiling sold price (call)	15,000	July 2015	December 2015	$	3.80
Floor sold price (put)	15,000	July 2015	December 2015	$	3.00
Natural Gas Put Options:					
Put sold	16,800	July 2015	December 2015	$	3.35
Put sold	16,800	July 2015	October 2015	$	2.87
Put purchased	16,800	July 2015	October 2015	$	3.35
Put sold	16,800	January 2016	December 2016	$	2.75
Basis Swaps:					
	25,000	July 2015	October 2015	$	(1.21)

Oil Derivatives

Description	Volume (Bbls/d)	Production Period		Weighted Average Price ($/Bbl)	
Oil Collar:					
Floor purchase price (put)	3,000	July 2015	February 2016	$	55.00
Ceiling sold price (call)	3,000	July 2015	February 2016	$	61.40
Oil Three-way Collar:					
Floor purchase price (put)	1,000	March 2016	December 2016	$	60.00
Ceiling sold price (call)	1,000	March 2016	December 2016	$	70.10
Floor sold price (put)	1,000	March 2016	December 2016	$	45.00

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

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credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have derivative instruments in place with Bank of Montreal and Key Bank NA. We believe both institutions currently are an acceptable credit risk. As of June 30, 2015, we did not have any past due receivables from counterparties.

A sensitivity analysis has been performed to determine the incremental effect on future earnings, related to open derivative instruments at June 30, 2015. A hypothetical 10 percent decrease in future natural gas prices would increase future earnings related to derivatives by $4.6 million. Similarly, a hypothetical 10 percent increase in future natural gas prices would decrease future earnings related to derivatives by $5.1 million. A hypothetical 10 percent decrease in future oil prices would increase future earnings related to derivatives by $4.3 million. Similarly, a hypothetical 10 percent increase in future oil prices would decrease future earnings related to derivatives by $4.8 million.

Subsequent to June 30, 2015, we entered into the following derivative instruments to mitigate our exposure to natural gas prices:

Natural Gas:	*(MMBtu/d)*	**Production Period**		**Weighted Average Price ($/MMbtu)**	
Natural Gas Collar:					
Floor purchase price (put)	30,000	January 2016	December 2017	$	3.00
Ceiling sold price (call)	30,000	January 2016	December 2017	$	3.50

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, 2015, costs incurred for drilling projects were $195.2 million, compared to $259.8 million for the six months ended June 30, 2014. There were no significant acquisitions of mineral properties in the six months ended June 30, 2015 and 2014. Our fiscal 2015 capital program, excluding acquisitions, was funded by net cash flow from operations, proceeds from asset sales and proceeds from the issuances of common stock.

As a result of the current pricing environment, we reduced our 2015 capital expenditure budget (excluding acquisitions, other than leasehold acquisitions) from $640 million to $352 million. This represents a 45% reduction from our initial 2015 capital budget and a 57% decrease from our 2014 capital expenditures. We expect to fund our capital expenditures for 2015 with cash generated by operations, borrowings under our Revolving Credit Facility, proceeds from asset sales, the remaining proceeds from the private placement of common stock that we completed in January 2015, a portion of the proceeds from the issuance of our Notes and proceeds from additional debt or equity offerings. 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 further decrease in our actual capital expenditures, which would negatively impact our ability to grow production and our proved reserves. 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, 2015 and December 31, 2014, our total debt, excluding debt discount, and capitalization were as follows (in millions):

	June 30, 2015	December 31, 2014
Senior PIK Notes	$ 437.3	$ 422.5
Stockholders equity	1,513.0	1,152.7
Total capitalization	$ 1,950.3	$ 1,575.2

Cash Contractual Obligations

Our contractual obligations include long-term debt, operating leases, drilling commitments, firm transportation, gas processing, gathering, and compressions services and asset retirement obligations. As of June 30, 2015 and December 31, 2014, we did not have any capital leases, any significant off-balance sheet debt or other such unrecorded obligations, and we have not guaranteed any debt of any unrelated party. Our condensed consolidated balance sheet at June 30, 2015 reflects accrued interest payable of $26.3 million, compared to $25.2 million as of December 31, 2014.

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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 five years. 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, 2015, we had $437.3 million as compared to $422.5 million as of December 31, 2014, of Senior PIK Notes outstanding, excluding discounts, which bore interest at a fixed cash interest rate of 12.0% and was due semi-annually from the date of issuance. At our option, the first two interest payments were payable in PIK Interest at a 13% per annum interest rate. Also at our option, the subsequent four semi-annual interest payments thereafter were payable 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 was only payable in cash at a 12.0% per annum interest rate.

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior notes due 2023 (the Notes) at an issue price of 97.903% of the principal amount of the Notes, plus accrued and unpaid interest, if any, to Deutsche Bank Securities Inc. and other initial purchasers. In this private offering, the Notes were sold for cash to qualified institutional buyers in the United States pursuant to Rule 144A of the Securities Act and to persons outside the United States in compliance with Regulation S under the Securities Act. Upon closing, we received proceeds of approximately $525.5 million, after deducting original issue discount, the initial purchasers discounts and estimated offering expenses, of which we used approximately $510.7 million to finance the redemption of all of our outstanding Senior PIK Notes on July 13, 2015. We intend to use the remaining net proceeds to fund our capital expenditure plan and for general corporate purposes.

In February 2014, we entered into a $500 million senior secured revolving bank credit facility which was amended and restated on January 12, 2015, and further amended and restated on June 11, 2015 and matures in 2018. Borrowings under our Revolving Credit Facility are subject to borrowing base limitations based on the collateral value of our proved properties and commodity hedge positions and are subject semiannual redeterminations. At December 31, 2014, the borrowing base was $100 million and we had no outstanding borrowings. In March 2015, we had a redetermination of the borrowing base, which increased the borrowing base to $125 million as of June 30, 2015. After giving effect to our outstanding letters of credit issued by the Company, totaling $27.8 million, we had available borrowing capacity under our Revolving Credit Facility of $97.2 million at June 30, 2015.

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 2015 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; exploration expenses; and other unusual or infrequent items. Adjusted EBITDAX, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with U.S. GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with U.S. GAAP.

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Adjusted EBITDAX provides no information regarding a company s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

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

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

- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under 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,		Six Months ended June 30,	
	2015	2014	2015	2014
Net loss	$ (41,970)	$ (112,648)	$ (76,073)	$ (131,099)
Depreciation, depletion & amortization	60,641	9,957	103,073	21,984
Exploration expense	6,243	9,295	19,696	13,840
Rig contract termination	366		7,423	
Stock-based compensation	1,410	27	2,157	56
Accretion of asset retirement obligations	399	191	785	377
Gain on reduction of pension obligations				(2,208)
(Gain) loss on derivative instruments	3,523	863	(7,848)	4,474
Net cash received (paid) on derivative instruments	8,457	(790)	14,422	(2,231)
Net cash paid for option premium		(141)		(141)
Interest expense	14,401	11,618	28,422	25,254
Gain on sale of assets	(5,553)		(5,473)	
Other income	2	(1,585)	(400)	(1,585)
Income tax (benefit) expense	(16,412)	94,541	(33,991)	94,541

Adjusted EBITDAX	**$ 31,507**	**$ 11,328**	**$ 52,193**	**$ 23,262**

Critical Accounting Estimates

Our discussion and analysis of our financial condition and results of operations are based upon our condensed consolidated financial statements, which have been prepared in accordance with U.S. GAAP. The preparation of these financial statements requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. See our Annual Report on Form 10-K for further discussion of our critical accounting policies.

Recent Accounting Pronouncements

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

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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 72% of our December 31, 2014 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 Note 5 *Derivative Instruments*.

Interest Rate Risk

At June 30, 2015, the cash interest rate with respect to our $437.3 million of Senior PIK Notes was fixed at 12.0%, and was due semi-annually from the date of issuance.

On July 6, 2015, we issued $550 million in aggregate principal amount of 8.875% senior notes due 2023 (the Notes) at an issue price of 97.903% of the principal amount of the Notes, plus accrued and unpaid interest, if any.

We will be exposed to interest rate risk in the 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 June 30, 2015, the borrowing base was $125 million and we had no outstanding borrowings. After giving effect to our outstanding letters of credit, totaling $27.8 million, we had available borrowing capacity under the Revolving Credit Facility of $97.2 million at June 30, 2015.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts, the sale of our oil and gas production which we market to energy companies, end users and refineries, and joint interest receivables.

We are exposed to credit risk in the event of nonperformance by counterparties. The creditworthiness of counterparties is subject to periodic review. We have not experienced any issues of nonperformance by derivative counterparties. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of June 30, 2015, we did not have past-due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

Item 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

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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

There has been no change in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15(d)-15(f) under the Exchange Act) during the period covered by this Quarterly Report that has materially affected, or is reasonable likely to materially affect, the Company s internal control over financial reporting.

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 Consolidated Financial Statements included in Part I Item 1 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 Annual Report on Form 10-K and filed with the SEC on March 9, 2015, which could materially affect our business, financial condition, and/or future results. The risks described in our Annual Report on Form 10-K 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 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, 2015

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	Amended and Restated Registration Rights Agreement, dated January 28, 2015, by and among Eclipse Resources Corporation, Eclipse Resources Holdings, L.P., CKH Partners II, L.P., The Hulburt Family II Limited Partnership, Kirkwood Capital, L.P, EnCap Energy Capital Fund VIII, L.P., EnCap Energy Capital Fund VIII Co-Investors, L.P., EnCap Energy Capital Fund IX, L.P., Eclipse Management, L.P., Buckeye Investors L.P., GSO Capital Opportunities Fund II (Luxembourg) S.à.r.l., Fir Tree Value Master Fund, L.P., Luxor Capital Partners, LP and Luxor Capital Partners Offshore Master Fund, LP (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on January 29, 2015).
10.1	Second Amended and Restated Credit Agreement, dated as of June 11, 2015, by and among Eclipse Resources Corporation, as borrower, Bank of Montreal, as administrative agent, and each of the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on June 12, 2015).
10.2	Purchase Agreement, dated as of June 19, 2015, by and among Eclipse Resources Corporation, the subsidiary guarantors named therein and Deutsche Bank Securities Inc., as representative of the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K filed with the SEC on June 22, 2015).
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.
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.