ALLEGHENY TECHNOLOGIES INC
Form 8-K
January 28, 2014
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, DC 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): January 28, 2014

Allegheny Technologies Incorporated
(Exact name of registrant as specified in its charter)

Delaware	1-12001	25-1792394
(State or other jurisdiction	(Commission	(IRS Employer
of incorporation)	File Number)	Identification No.)

1000 Six PPG Place, Pittsburgh, Pennsylvania	15222-5479
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (412) 394-2800

N/A
(Former name or former address, if changed since last report).

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Item 8.01. Other Events.

On January 28, 2014, Allegheny Technologies Incorporated announced that it has named a Chief Commercial and Marketing Officer, effective February 3, 2014. A copy of the press release is attached hereto as Exhibit 99.1.

Item 9.01. Financial Statements and Exhibits

(d) Exhibits

99.1 Press release dated January 28, 2014.

SIGNATURE

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 hereunto duly authorized.

ALLEGHENY TECHNOLOGIES INCORPORATED

By: */s/ Elliot S. Davis*
Elliot S. Davis
Senior Vice President, General Counsel,
Chief Compliance Officer and Corporate Secretary

Dated: January 28, 2014

border-bottom-width: 1"> Class B Common Stock (2) 03/29/2007 C 37,400 (2) (2) Class A Common Stock 37,400 (2) 10,176,740 I By Greenberg Family Trust Class B Common Stock (2) 03/30/2007 C 44,900 (2) (2) Class A Common Stock 44,900 (2) 10,131,840 I By Greenberg Family Trust

Reporting Owners

Reporting Owner Name / Address	Relationships			
	Director	10% Owner	Officer	Other
GREENBERG ROBERT 228 MANHATTAN BEACH BLVD. MANHATTAN BEACH, CA 90266	X	X	Chief Executive Officer	
GREENBERG M SUSAN 228 MANHATTAN BEACH BLVD. MANHATTAN BEACH, CA 90266		X		
GREENBERG FAMILY TRUST 228 MANHATTAN BEACH BLVD. MANHATTAN BEACH, CA 90266		X		

Signatures

Robert Greenberg	04/02/2007
**Signature of Reporting Person	Date
M. Susan Greenberg	04/02/2007
**Signature of Reporting Person	Date
Robert Greenberg; M. Susan Greenberg	04/02/2007
**Signature of Reporting Person	Date

Explanation of Responses:

* If the form is filed by more than one reporting person, *see* Instruction 4(b)(v).

** Intentional misstatements or omissions of facts constitute Federal Criminal Violations. *See* 18 U.S.C. 1001 and 15 U.S.C. 78ff(a).

(1) Each share of Class A Common Stock was issued upon conversion of one share of Class B Common Stock for no additional consideration.

(2) Shares of Class B Common Stock are convertible into Class A Common Stock on a one-for-one basis for no additional consideration at any time, with no expiration date, upon voluntary conversion by the holder of such shares or upon any sale or transfer of such shares with certain exceptions.

Note: File three copies of this Form, one of which must be manually signed. If space is insufficient, *see* Instruction 6 for procedure.
Potential persons who are to respond to the collection of information contained in this form are not required to respond unless the form displays a currently valid OMB number. "bottom">

Cash

$987,100 $2,727,832

Accounts receivable, trade

7,423,500 4,460,535

Accounts receivable from drilling operator

704,677

Accounts receivable, related parties

18,500 18,500

Advance royalties

12,032 16,937

Prepaid expenses

4,309,551 1,065,061

Deferred financing costs, net of amortization of $78,157 and $1,308,817, respectively

937,887 817,938

Total current assets

14,393,247 9,106,803

OIL AND GAS PROPERTIES, USING SUCCESSFUL EFFORTS ACCOUNTING

Proved properties

85,096,460 77,961,183

Unproved properties

7,471,793 15,092,783

Pipelines

1,397,440 1,397,440

Accumulated depreciation, depletion and amortization

(18,712,023) (14,473,069)

Oil and gas properties, net

75,253,670 79,978,337

PROPERTY AND EQUIPMENT, net of accumulated depreciation of $361,288 and $317,704, respectively

545,721 587,218

OTHER ASSETS

Deferred financing costs

	3,282,603	139,076
Other assets	304,877	303,887
Total other assets	3,587,480	442,963
TOTAL ASSETS	$93,780,118	$90,115,321

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Balance Sheets (continued)

Unaudited

	June 30, 2014 Unaudited	December 31, 2013 Audited
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable, trade	$ 722,167	$ 632,795
Accounts payable due to drilling operator		2,698,302
Accounts payable, related party	1,500	1,500
Accrued expenses	4,238,871	5,302,816
Deferred gain on sale of assets	6,959,816	
Revenue payable	66,858	127,106
Commodity derivative liability	883,426	58,176
Notes payable current	11,934	14,897
Notes payable, related party		205,314
Total current liabilities	12,884,572	9,040,906
LONG-TERM LIABILITIES		
Notes payable, net	99,021,340	89,204,102
Asset retirement obligations	66,184	41,440
Commodity derivative liability	1,817,928	67,597
Total long-term liabilities	100,905,452	89,313,139
Total liabilities	113,790,024	98,354,045
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Preferred stock; 10,000,000 shares authorized at $0.001 par value; -0- shares issued and outstanding		
Common stock; 500,000,000 shares authorized at $0.001 par value; 13,647,309 and 13,457,978 shares issued, respectively, and 13,645,309 and 13,455,978 shares outstanding, respectively	13,647	13,458
Additional paid-in capital	43,263,065	42,556,292
Treasury stock, at cost, 2,000 shares	(1,950)	(1,950)
Accumulated deficit	(63,284,668)	(50,806,524)
Total stockholders equity (deficit)	(20,009,906)	(8,238,724)
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 93,780,118	$ 90,115,321

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Statements of Operations (Unaudited)

	For the Three Months Ended June 30, 2014	For the Three Months Ended June 30, 2013	For the Six Months Ended June 30, 2014	For the Six Months Ended June 30, 2013
OPERATING REVENUES				
Oil and gas sales	$ 8,432,592	$ 4,641,723	$ 18,149,015	$ 8,215,606
Gas transportation, gathering, and processing	22,830	26,447	77,619	61,890
Other income	1,303	2,988	6,433	2,988
Total operating revenues	8,456,725	4,671,158	18,233,067	8,280,484
OPERATING COSTS AND EXPENSES				
Production costs	3,489,282	2,248,851	6,745,232	4,568,491
Depreciation, depletion, amortization and accretion	2,248,970	739,161	4,360,695	1,378,610
Selling, general and administrative	1,534,477	1,540,089	2,982,296	3,100,428
Total operating costs and expenses	7,272,729	4,528,101	14,088,223	9,047,529
(Loss) Gain on sale of assets	(298)		207,097	(8,787)
INCOME (LOSS) FROM OPERATIONS	1,183,698	143,057	4,351,941	(775,832)
OTHER INCOME (EXPENSES)				
Interest income	585	9,858	1,494	14,679
Interest expense	(9,674,758)	(3,898,628)	(13,805,951)	(5,801,375)
Gain on warrant derivatives		467,762		591,439
Gain (loss) on derivative assets	(2,459,436)	659,356	(3,025,628)	659,356
Total other income (expenses)	(12,133,609)	(2,761,652)	(16,830,085)	(4,535,901)
NET LOSS BEFORE INCOME TAXES	(10,949,911)	(2,618,595)	(12,478,144)	(5,311,733)
INCOME TAX				
NET LOSS	$ (10,949,911)	$ (2,618,595)	$ (12,478,144)	$ (5,311,733)
NET LOSS PER SHARE BASIC AND DILUTED	$ (0.81)	$ (.20)	$ (0.92)	$ (.40)
WEIGHTED AVERAGE SHARES BASIC AND DILUTED	13,590,048	13,237,126	13,553,423	13,236,680

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Condensed Consolidated Statements of Cash Flows

(Unaudited)

	For the Six Months Ended June 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (12,478,144)	$ (5,311,733)
Adjustments to reconcile net loss to net cash used by operating activities:		
Depreciation, depletion, amortization and accretion	4,360,695	1,378,610
Amortization of financing costs and debt discount	8,426,119	855,684
Share-based compensation	483,216	635,863
(Gain) loss on sale of assets	(207,097)	8,787
Interest and legal expense added to principal	1,818,240	1,005,000
Unrealized gain on warrant derivative		(591,439)
Unrealized loss (gain) on commodity derivative assets	2,575,581	(659,995)
Realized loss on commodity derivative assets	450,047	639
Changes in operating assets and liabilities:		
Accounts receivable, trade	(2,962,965)	(757,792)
Accounts receivable due from operator, net	(704,677)	
Prepaid expenses and other current assets	(3,239,585)	46,780
Other assets	(990)	(975)
Accounts payable and accrued expenses	230,583	600,710
Revenue payable	(60,248)	(64,558)
Net cash used by operating activities	(1,309,225)	(2,854,419)
CASH FLOWS FROM INVESTING ACTIVITIES:		
Proceeds from sale of assets	15,259,543	2,618,025
Expenditures for oil and gas properties	(16,008,089)	(7,654,169)
Expenditures for property and equipment	(2,087)	(5,961)
Net cash used by investing activities	(750,633)	(5,042,105)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Financing costs paid	(4,298,647)	(116,555)
Payments on notes payable	(98,699,723)	(11,216)
Proceeds from notes payable	103,093,750	25,000,000
Stock options exercised	223,746	13,750
Net cash provided by financing activities	319,126	24,885,979
NET CHANGE IN CASH	(1,740,732)	16,989,455
CASH, BEGINNING OF PERIOD	2,727,832	1,009,084

CASH, END OF PERIOD	$ 987,100	$ 17,998,539
SUPPLEMENTAL DISCLOSURES FOR CASH FLOW INFORMATION:		
CASH PAID FOR:		
Interest	$ 5,648,315	$ 3,751,874
Income taxes		
Non-cash investing and financing activities:		
Accrued expenditures for oil and gas properties	$ (3,443,366)	$ 4,779,315
Increase in asset retirement obligation	$ 24,744	$ 1,840

See notes to unaudited condensed consolidated financial statements.

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TRANS ENERGY, INC. AND SUBSIDIARIES

Notes to Condensed Consolidated Financial Statements (Unaudited)

NOTE 1 BASIS OF FINANCIAL STATEMENT PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

The accompanying unaudited interim condensed consolidated financial statements have been prepared by Trans Energy, Inc., (Trans Energy, we, our, us, or the Company), in accordance with accounting principles generally accepted in the United State of America (GAAP) for interim financial information and with the instructions to Form 10-Q and Rule 8-03 of Regulation S-X. Accordingly, they do not include certain information and footnote disclosures normally included in a full set of financial statements prepared in accordance with GAAP. The information furnished in the interim condensed consolidated financial statements includes normal recurring adjustments and reflects all adjustments, which, in the opinion of management, are necessary for a fair presentation of such financial statements. Although management believes the disclosures and information presented are adequate to make the information not misleading, these interim consolidated financial statements should be read in conjunction with our most recent audited consolidated financial statements and notes thereto included in our December 31, 2013 Annual Report on Form 10-K. Operating results for the six months ended June 30, 2014 are not necessarily indicative of the results that may be expected for the year ending December 31, 2014.

Significant Accounting Policies

The accounting policies followed by the Company are set forth in Note 1 to the Company s consolidated financial statements in the 2013 Form 10-K, and are supplemented by the notes to the unaudited condensed consolidated financial statements in this report.

Nature of Operations and Organization

We are an independent energy company engaged in the acquisition, exploration, development, exploitation and production of oil and natural gas. Our operations are presently focused in the State of West Virginia.

Principles of Consolidation

The unaudited consolidated financial statements include Trans Energy and our wholly-owned subsidiaries, Prima Oil Company, Inc. (Prima), Ritchie County Gathering Systems, Inc., Tyler Construction Company, Inc., American Shale Development, Inc. (American Shale or ASD), and Tyler Energy, Inc., and interests with joint venture partners, which are accounted for under the proportional consolidation method. All significant inter-company balances and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. Our financial statements are based on a number of significant estimates, including oil and gas reserve quantities which are the basis for the calculation of depreciation, depletion, amortization, and impairment of oil and gas properties, timing and costs associated with our asset retirement obligations, estimates of fair value of derivative instruments and estimates used in stock-based compensation calculations. Reserve estimates are by their nature inherently imprecise.

Financing Costs

In connection with obtaining the Morgan Stanley financing in May 2014, we incurred fees and expenses of $4,298,647. These fees and expenses were recorded as financing costs and are being amortized over the life of the loan using the straight-line method, which approximates the effective interest method.

In October 2013 we reached a settlement with Oppenheimer & Co., Inc. (Opco) which related to the amount of the fee which was earned by Opco acting as our investment banker in assisting the Company in obtaining funding (Tranche A) with Chambers Energy Capital (Chambers). We recorded $401,625 in financing fees related to the settlement. The Opco financing fees were being amortized over the same period as the Tranche A loan. In addition, when we obtained new financing in February 2013 and April 2012, we incurred $122,230 in fees during 2013 and $1,741,976 in 2012. These fees were recorded as financing costs and were being amortized over the life of the loan using the straight-line method, which approximates the effective interest method. When we obtained the Morgan Stanley financing, the remaining balance of the finance fees related to the Chambers financing were expensed due to the payoff of the related loan.

Amortization of financing costs for the three months ended June 30, 2014 and 2013 were $3,123,838 and $169,047, respectively. Amortization of financing costs for the six months ended June 30, 2014 and 2013 were $3,328,323 and $331,948, respectively. Our policy is to recognize twelve months of deferred financing costs as a current asset and the remaining balance of deferred financing costs as other assets in the condensed consolidated balance sheets.

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Property and Equipment

Property and equipment are recorded at cost. Depreciation on vehicles, machinery and equipment is computed using the straight-line method over expected useful lives of five to ten years. Additions are capitalized and maintenance and repairs are charged to expense as incurred.

Oil and Gas Properties

Trans Energy uses the successful efforts method of accounting for oil and gas producing activities. Under the successful efforts method, costs to acquire mineral interests in oil and gas properties, to drill and equip exploratory wells that find proved reserves, and to drill and equip development wells and asset retirement costs are capitalized. Costs to drill exploratory wells that do not find proved reserves, geological and geophysical costs, and costs of carrying and retaining unproved properties are expensed as incurred.

Unproved oil and gas properties that are individually significant are periodically assessed for impairment of value, and a loss is recognized at the time of impairment by providing an impairment allowance. Other unproved properties are amortized based on Trans Energy s experience of successful drilling and average holding period. Capitalized costs of producing oil and gas properties, after considering estimated dismantlement and abandonment costs and estimated salvage values, are depreciated and depleted by the unit-of-production method. Depreciation on pipelines and related equipment, including compressors, is computed using the straight-line method over the expected useful lives of ten to twenty-five years.

On the sale or retirement of a proved property, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and the resultant gain or loss is recognized.

On the sale of an entire interest in an unproved property for cash or cash equivalent, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually.

If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Impairments

Generally accepted accounting principles require that long-lived assets (including oil and gas properties) and certain identifiable intangibles be reviewed for impairment whenever events or changes in circumstances indicated that the carrying amount of an asset may not be recoverable. The Company, at least annually, reviews its proved oil and gas properties for impairment by comparing the carrying value of its properties to the properties undiscounted estimated future net cash flows. Estimates of future oil and gas prices, operating costs, and production are utilized in determining undiscounted future net cash flows. The estimated future production of oil and gas reserves is based upon the Company s independent reserve engineer s estimate of proved reserves, which includes assumptions regarding field decline rates and future prices and costs. For properties where the carrying value exceeds undiscounted future net cash flows, the Company recognizes as impairment the difference between the carrying value and fair market value of the properties.

In January 2013, the Company sold certain shallow wells for approximately $11.5 million. We determined that the sales price negotiated with the independent buyer represented the fair market value of those properties as of December 31, 2012. Accordingly, the Company recorded an impairment of approximately $10.1 million in 2012 so that the carrying value of those properties as of December 31, 2012 were equal to the subsequent sales price.

No impairments were recorded through June 30, 2014 or 2013.

Derivatives

We may enter into derivative commodity contracts at times to manage or reduce commodity price risk related to our production. Derivatives and embedded derivatives, if applicable, are measured at fair value and recognized in the consolidated balance sheets as assets or liabilities. Derivatives are classified in the consolidated balance sheets as current or non-current based on whether net-cash settlement is expected to be required within 12 months of the balance sheet date. These commodity contracts are not designated as cash flow hedges, so changes in the fair value are recognized immediately in other income (expense) in the consolidated statement of operations. The pricing models used for valuation often incorporate significant estimates and assumptions, which may impact the level of precision in the financial statements.

We have determined that the warrant previously issued for equity of one of our wholly-own subsidiaries was a derivative liability prior to being settled in December 2013.

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Notes Payable

We record notes payable at fair value and recognize interest expense for accrued interest payable under the terms of the agreements. Principal and interest payments due within one year are classified as current, whereas principal and interest payments for periods beyond one year are classified as long term.

Asset Retirement Obligations

We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. These obligations include dismantlement, plugging and abandonment of oil and gas wells and associated pipelines and equipment. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depleted over the estimated useful life of the related asset which has been determined to be 40 years for Marcellus Shale wells.

The following is a description of the changes to our asset retirement obligations for the six months ended June 30:

	2014	2013
Asset retirement obligations at beginning of period	$ 41,440	$ 416,322
Liabilities incurred during the period	22,744	
Accretion expense	2,000	1,840
Liabilities held for sale		(388,005)
Asset retirement obligations at end of period	$ 66,184	$ 30,157

At June 30, 2014 and December 31, 2013, our current portion of the asset retirement obligation was $0. In addition, asset retirement obligations related to the shallow wells sold in 2013 was reported as a liability of $388,005 at December 31, 2012.

Income Taxes

At June 30, 2014, the Company had net operating loss carry forwards (NOLs) for future years of approximately $65.2 million. These NOLs will expire at various dates through 2033. There is no current tax provision for the three or six months ended June 30, 2014 due to a net operating loss for the period. No tax benefit has been recorded in the consolidated financial statements for the remaining NOLs or Alternative Minimum Tax (AMT) credit since the potential tax benefit is offset by a valuation allowance of the same amount. Utilization of the NOLs could be limited if there is a substantial change in ownership of the Company and is contingent on future earnings.

We have provided a valuation allowance equal to 100% of the total net deferred asset in recognition of the uncertainty regarding the ultimate amount of the net deferred tax asset that will be realized.

The Company has no material unrecognized tax benefits. No tax penalties or interest expense were accrued as of June 30, 2014 or December 31, 2013 or paid during the periods then ended. We file tax returns in the United States and states in which we have operations and are subject to taxation. Tax years subsequent to 2009 remain open to examination by U.S. federal and state tax jurisdictions, however prior year net operating losses remain open for examination.

Revenue and Cost Recognition

We recognize gas revenues upon delivery of the gas to the customers pipeline from our pipelines when recorded as received by the customer s meter. We recognize oil revenues when pumped and metered by the customer. We use the sales method to account for sales and imbalances of natural gas. Under this method, revenues are recognized based on actual volumes sold to purchasers. The volumes sold may differ from the volumes to which we are entitled based on our interest in the properties. These differences create imbalances which are recognized as a liability only when the imbalance exceeds the estimate of remaining reserves. We had no material imbalances as of June 30, 2014 and December 31, 2013. Costs associated with production are expensed in the period incurred.

Revenue payable represents cash received but not yet distributed to third parties.

Transportation revenue is recognized when earned and we have a contractual right to receive payment.

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On January 1, 2013, the Company adopted new authoritative accounting guidance issued by the Financial Accounting Standards Board (FASB), which enhanced disclosures by requiring an entity to disclose information about netting arrangements, including rights of offset, to enable users of its financial statements to understand the effect of those arrangements on its financial position and provided clarification as to the specific instruments that should be considered in these disclosures. These pronouncements were issued to facilitate comparison between financial statements prepared on the basis of GAAP and International Financial Reporting Standards. These disclosures are effective for annual and interim reporting periods beginning on or after January 1, 2013, and are to be applied retrospectively for all comparative periods presented. See Note 7 - Derivative and Hedging Financial Instruments for tabular presentation of the Company s gross and net derivative positions.

Share-Based Compensation

Trans Energy estimates the fair value of each stock option award at the grant date by using the Black-Scholes option pricing model. The model employs various assumptions, based on management s best estimates at the time of the grant, which impact the fair value calculated and ultimately, the expense that is recognized over the life of the award. We have utilized historical data and analyzed current information to reasonably support these assumptions. The fair value of restricted stock awards is determined based on the fair market value of our common stock on the date of the grant.

We recognize share-based compensation expense on a straight-line basis over the requisite service period for the entire award. As a result of stock and option transactions, we recorded total share-based compensation of $284,675 and $325,801 for the three months ended June 30, 2014 and 2013, respectively. We also recorded total share-based compensation of $483,216 and $635,863 for the six months ended June 30, 2014 and 2013, respectively.

New Accounting Standards

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, Revenue from Contracts with Customers (Topic 606) (ASU 2014-09). ASU 2014-09 is intended to improve the financial reporting requirements for revenue from contracts with customers by providing a principle based approach. The core principal of the standard is that revenue should be recognized when the transfer of promised goods or services is made in an amount that the entity expects to be entitled to in exchange for the transfer of goods and services. ASU 2014-09 also requires disclosures enabling users of financial statements to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. This standard will be effective for financial statements issued by public companies for annual reporting periods beginning after December 15, 2016. Early adoption is not permitted. The Company is currently evaluating the potential impact of ASU 2014-09 on the financial statements.

The Company has reviewed all other recently issued accounting standards in order to determine their effects, if any, on the consolidated financial statements. Based on that review, the Company believes that none of these standards will have a significant effect on current or future earnings or results of operations.

Reclassification

Certain reclassifications have been made to the 2013 financial presentation to correspond to the current year s format.

NOTE 2 OPERATIONS

We have incurred net losses for the three months and six months ended June 30, 2014, of $(10,949,911) and $(12,478,144), respectively. Although our current and prior year-to-date revenues were not sufficient to cover our operating costs and interest expense, we are focusing on drilling Marcellus Shale wells which, based upon projections, are expected to increase our cash flow. If our cash flows from operations are not sufficient to meet liquidity requirements, we may need to sell assets, obtain additional financing or issue equity.

Our net losses and cash flows used in operating and investing activities during the six months ended June 30, 2014 and 2013 were primarily funded using net proceeds from notes payable to Chambers and Morgan Stanley (see Note 6), in addition to proceeds from the sale of certain oil and gas properties (see Note 5).

NOTE 3 ACCOUNTS PAYABLE DUE TO DRILLING OPERATOR

We have historically been the drilling operator for wells drilled on our behalf and other third parties in which we own a working interest. In 2012, another working interest owner became the drilling operator for wells in which we own a working interest. We owed the drilling operator $0 and $2,698,302 for charges incurred, but not paid, as of June 30, 2014 and December 31, 2013, respectively. The amount due to the operator reported at June 30, 2014 has been reduced for consideration received from the Republic purchase and sale agreement, which is to be paid in the form of a credit against the expenses incurred by Republic Energy Ventures on behalf of American Shale (see Note 5). The amount due to the operator reported at December 31, 2013, is net of a $637,667 credit, related to a refund of prior drilling costs previously invoiced to America Shale for wells we are not participating in as well as intercompany charges related to employee salary reimbursements, travel expenses, and lease costs.

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NOTE 4 OIL AND GAS PROPERTIES

Total additions for oil and gas properties for the three months ended June 30, 2014 and 2013 were $14,021,282 and $6,276,278, respectively. Total additions for oil and gas properties for the six months ended June 30, 2014 and 2013 were $16,008,089 and $7,654,169, respectively. Depreciation, depletion, and amortization expenses on oil and gas properties were $2,148,847 and $717,643 for the three months ended June 30, 2014 and 2013, respectively. Depreciation, depletion, and amortization expenses on oil and gas properties were $4,238,454 and $1,333,957 for the six months ended June 30, 2014 and 2013, respectively.

NOTE 5 SALE OF OIL AND GAS PROPERTIES

On January 24, 2013, we closed the sale of our interests in certain non-core assets for approximately $2.6 million of net cash proceeds. The interests sold consisted of our working interest in all existing shallow wells, but we retained an overriding royalty interest of approximately 2.5% on most of the wells. The purchaser assumed the role of operator with respect to approximately 300 wellbores, and has commenced a workover program with respect to a number of the existing wells. The wells produced at a rate of approximately 800 Mcfe per day as of December 31, 2012, which was the effective date for the transaction.

Additionally, we granted the purchaser the right to drill wells in or above conventional shallow Devonian formations, for leases where we currently hold rights to such depths. We did not farm out any of our rights to drill in deeper formations such as the Rhinestreet, Marcellus or Utica. We retained up to a 5% overriding royalty interest on any such wells drilled, depending on the net revenue interest.

On December 13, 2013, the Company and Republic closed a transaction pursuant to a Purchase and Sale Agreement (the PSA) dated September 30, 2013. The Company owned 1,114.8 lease acres of the total 4,650 lease acres and leasehold working interests in certain partially completed well sites, located in Tyler County, West Virginia. At closing, the Company received cash of approximately $10.6 million of the total purchase price of $36.3 million, net of holdback. A total of 118.6 lease acres were excluded from the sale (39.8 lease acres net to the Company) due to incurable title defects. An additional 135.5 lease acres (30.7 lease acres net to the Company) were excluded from the sale due to curable title defects, which were cured and an additional $0.2 million was due and payable to the Company, as of December 31, 2013, per the terms of the PSA. In February 2014, the Company received $489,608 related to curable title defects. The proceeds were applied to a receivable of $230,064 recorded at December 31, 2013. The remaining $259,544 is reported, net of expenses, as gain on sale of assets for the period ended June 30, 2014.

On May 21, 2014 (Funding Date), American Shale entered into a purchase and sale agreement (the Republic PSA) with its joint venture partner, Republic Energy Ventures (Republic). Under the Republic PSA, for $15 million, American Shale sold (i) an undivided interest across certain of its undeveloped leasehold amounting to approximately 2,239 net acres, (ii) an over-riding royalty interest of 1.5% in certain of its leasehold in Wetzel County, West Virginia, and (iii) an over-riding royalty interest of 1.0% in six (6) wells that are currently being drilled in Marshall County, West Virginia. The consideration is to be paid in the form of a credit against expenses incurred by Republic on behalf of American Shale. American Shale reserved the right to receive 25% of the net profits earned by Republic on the assets sold by American Shale under the Republic PSA. American Shale has the option to repurchase the undivided interest across all of its undeveloped leasehold, plus the over-riding royalty interest in its Wetzel County leasehold, for $15 million if (i) such payment is made within six (6) months of the Funding Date, or (ii) a purchase and sale agreement that would allow for such repayment by American Shale is signed within such period and the transaction contemplated therein is closed prior to December 31, 2014. The Company has recognized a deferred gain on sale of assets in the current liabilities section of the Condensed Consolidated Balance Sheet in the amount of $6,959,816 because the Company has the option of repurchasing the undivided interest across all of its undeveloped leasehold, plus the overriding royalty interest in its Wetzel County leasehold by December 31, 2014.

As part of the Republic PSA, Republic also agreed to amend the Amended Joint Development Agreement with American Shale (the AJDA). Under the revised AJDA, Republic agreed to fund all costs associated with new leasehold acquisitions subsequent to April 1, 2014. American Shale has the right to buy a 25% interest in any such leasehold at Republic s cost, plus 12% interest, in the event that Republic sells its interest in the leasehold or permits a third party to drill a well on the leasehold. In the event that American Shale repays Republic under the terms of the Republic PSA, American Shale will have the option to fund a 50% portion of any future leasehold expenditures, upon providing satisfactory evidence of its ability to continue such funding on a go-forward basis.

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NOTE 6 NOTES PAYABLE

On April 26, 2012, our newly created, wholly owned subsidiary, American Shale , closed a Credit Agreement transaction (hereafter the ASD Credit Agreement) with several banks and other financial institutions or entities that from time-to-time will be parties to the ASD Credit Agreement (the Lenders), and Chambers Energy Management, LP as the administrative agent (Chambers).

The ASD Credit Agreement provided that the Lenders would lend American Shale up to $50 million, which funds would be used to develop wells and properties that we transferred to American Shale. In order to accommodate the terms of the ASD Credit Agreement Trans Energy transferred certain assets and properties to American Shale. Trans Energy and Prima were not direct parties to the ASD Credit Agreement, but were guarantors of loans to be made there under. We received a portion of the loan proceeds to repay CIT Capital USA Inc. (CIT) and certain other outstanding debts. The assets and properties transferred are referred to herein as the Marcellus Properties, which at the time of the transfer consisted of working interests in 13 gross (7.60 net) producing Marcellus shale liquids-rich gas wells and approximately 22,000 net acres of Marcellus shale leasehold rights, located in Northwestern West Virginia in the counties of Wetzel, Marshall, Marion, Tyler, and Doddridge.

The ASD Credit Agreement was originally for a notional amount of $50 million, which was received at closing net of a $3 million Original Issue Discount (OID) and a $50,000 administrative fee due annually. These OID costs were netted against notes payable and were being amortized over the life of the loan using the straight-line method, which approximates the effective interest method. For the six months ended June 30, 2014 and 2013, $1,189,400 and $529,412 of the OID was amortized as interest expense, respectively.

On February 28, 2013, American Shale, the Lenders and Chambers amended and restated the ASD Credit Agreement (as amended, the A&R Credit Agreement) in order to facilitate an increase in the principal amount of the borrowings under the facility to $75 million. The additional funds were received February 28, 2013. The other terms of the credit agreement were unchanged.

Interest was due monthly at 10% plus the greater of 1% or the 3 month LIBOR rate (11% at time of payoff). Principal was due at maturity, February 28, 2015. We had to pay interest through April 26, 2014, on any principal prepayments with respect to the original $50 million loan at the time of the prepayment prior to April 26, 2014. American Shale was obligated to pay a Termination Fee with respect to the $25 million loan upon the earliest to occur of (i) a Change of Control (as defined in the A&R Credit agreement), (ii) repayment in full of the loans under the A&R Credit agreement and (iii) certain defaults under the A&R Credit Agreement related to seeking relief from creditors or generally being unable to repay debts as they come due. The Termination Fee was defined as $12.5 million less all interest payments actually made with respect to the $25 million loan prior to such date.

The Company estimated its liability related to the Termination Fee to be approximately $6.8 million ($12.5 million gross fee, less $5.7 million in interest payments) (the Termination Fee Liability).

The Termination Fee Liability was recorded on the Company s condensed consolidated balance sheet as an addition to the related debt balance, offset by an equal debt discount of $6.8 million (the Termination Fee Debt Discount). The Termination Fee Debt Discount was being amortized to interest expense through the expected payment date of February 28, 2015; however, such amortization was accelerated upon payment of the Termination Fee in conjunction with the Morgan Stanley financing. At repayment of the loan the Termination Fee was computed to be $9,077,778.
For the three and six months ended June 30, 2014, the Company recorded $3,104,200 and $3,940,689 of amortization related to the Termination Fee.

During the three and six months ended June 30, 2014, the Company recorded interest expense of $278,821 and $1,115,280 related to the amortization of the Termination Fee Debt Discount.

The A&R Credit Agreement included a contingent interest provision that adds 1% of the outstanding principal amount of the loan to the loan balance for any quarter in which American Shale s Consolidated Leverage Ratio exceeds certain levels, as defined in the ASD Credit Agreement. American Shale s Consolidated Leverage Ratio exceeded the allowed level at September 30, 2012, and quarterly thereafter. Therefore, the contingent interest provision had been applied and $1,149,969 and $2,030,050 was added to the principal balance and interest expense in 2014 (through the date of the repayment) and June 30, 2013, respectively.

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For the months of August, September, and October 2013, Chambers amended the ASD Credit Agreement to add the interest due during those months to the principal balance of the loan. In addition, $375,000 was added to the principal balance of the loan in connection with this amendment. The $375,000 was being amortized over the three month period. August, September and October 2013 interest of $2,186,038 had been added to the principal balance of the loan.

On December 20, 3013, American Shale amended the A&R Credit Agreement to increase the principal amount of the borrowings by $7.5 million to pay a portion of the cost to purchase an outstanding warrant held by Chambers (See Note 7). There were no other changes to the terms of the loan. The additional funds were received December 20, 2013.

On May 21, 2014, our wholly owned subsidiary, American Shale, entered into a credit agreement (hereafter the Credit Agreement) by and among American Shale, several lenders (the Lenders), and Morgan Stanley Capital Group Inc. as the administrative agent (Agent). Trans Energy is a guarantor of the Credit Agreement as is Prima, another of our wholly owned subsidiaries. The Credit Agreement provides that the Lenders will lend American Shale up to $200 million, including an initial draw of $102.5 million plus a PIK fee of $593,750, a contingent committed amount of $47.5 million and an uncommitted amount of $50 million (the Loans). The initial draw under the facility was used primarily to repay all of the outstanding debt under the A&R Credit Agreement with Chambers, as well as to fund certain fees and expenses incurred in connection with the Credit Agreement (collectively, the Morgan Stanley Financing).

The Loans will initially bear interest at a per annum rate equal to 9% plus the greater of 1% or LIBOR, for a three month interest period. The interest rate will be automatically lowered if American Shale improves the ratio of the value of its proved developed producing (PDP PV9) properties to its funded debt, less cash and other liquid assets, as further defined under the Credit Agreement (the Net Debt Ratio). Upon the occurrence of certain events of default, the loans will bear interest at an additional 2% per annum above the initial rate, and with respect to other events of default, may bear interest at the higher default rate. Interest will be due and payable monthly in arrears. During the three months ending June 30, 2014, the Company recorded interest expense of $1,145,486 related to the Credit Agreement.

The initial loan was advanced as a single funding of $102.5 million plus a PIK fee of $593,750 on the Funding Date. Additional amounts up to $47.5 million may be drawn within the two year period after the Funding Date provided that the Net Debt Ratio, pro forma for such subsequent drawdowns, based on the level of PDP PV9 that is projected six months from the date of each drawdown, meets certain pre-defined targets. All principal will be due on December 31, 2018 (the Maturity Date), if not accelerated before that date. Scheduled amortization of the principal amount of the loans may begin on May 1, 2015, unless the Net Debt Ratio exceeds certain defined parameters, in which case scheduled amortization may begin as late as May 1, 2016. No amortization is required if American Shale s Net Debt Ratio meets certain criteria. The minimum amortization required each month will be the greater of (i) 0.75% of the then outstanding balance (after May 1, 2016) or (ii) the amortization amount that would be required for American Shale to achieve a predetermined Net Debt Ratio within six months. Such ratios increase over time.

The principal amount of the Loans may be prepaid, but not reborrowed. If the Loans are prepaid on or prior to the first anniversary of the Funding Date, a make-whole amount will be charged equal to 4.0% of the principal balance of the Loans, plus the sum of the remaining scheduled payments of interest prior to the first anniversary of the Funding Date. Up to $25 million of prepayments from specified sources will be exempt from this provision if payments are made prior to the first anniversary of the Funding Date. If the Loans are prepaid on or after the first anniversary of the Funding Date but prior to the second anniversary of the Funding Date, a make-whole amount equal to 4.0% of the principal balance of the Loans will be charged. Prepayments between the second and third anniversary of the Funding Date will be charged 3.0% of the principal balance of the Loans.

Also on the Funding Date of the Credit Agreement, Trans Energy and Prima executed a Guarantee and Security Agreement providing that Trans Energy and Prima will guarantee the indebtedness of American Shale under the terms of the Credit Agreement.

The Credit Agreement contains representations and warranties that are common in such agreements, including, but not limited to

- financial condition;
- material adverse effects;
- corporate existence;
- corporate authorizations and powers;
- enforceable obligations; and
- existing indebtedness and material litigation.

Other representations and warranties relate to operations such as environmental matters, gas imbalances, hedging agreements, reserve reports, sale of production and contingent obligations. The Credit Agreement also includes typical indemnification provisions.

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The Credit Agreement also includes certain customary affirmative covenants such as minimum hedging requirements, delivery of financial information, operation and maintenance of properties, and maintenance of books and records. Financial covenants include a maximum leverage ratio (latest twelve months EBITDA to net debt) and minimum current ratio (consolidated current assets to consolidated current liabilities). The definition of net debt includes funded debt plus accounts payable, offset by cash as well as accounts receivable. American Shale is also required to apply toward approved capital expenditures a minimum of 50% of the proceeds of any equity issuance that occurs subsequent to the first anniversary of the Funding Date.

Negative covenants include limitations on indebtedness, liens, fundamental changes, dispositions of property, payment of dividends or distributions, capital expenditures, investments and transactions with affiliates. There are also limitations on hedging transactions, creation or acquisition of subsidiaries, use of proceeds, drilling without providing title opinions, amending certain documents and appointing non-approved officers or directors.

Upon the occurrence of a change of control (as defined in the Credit Agreement), the Lenders may require American Shale to pay all of the outstanding interest, make-wholes and fees in addition to 101% of the principal amounts of the Loans under the Credit Agreement.

On the Funding Date, American Shale also entered into a Net Profits Interest Agreement (the NPI Agreement) with the Agent. The NPI Agreement provides that subsequent to the repayment of the Loans, American Shale will pay a net profits interest to the Agent (the NPI). The NPI is to be calculated based on production revenues less certain expenditures, including operating costs, general and administrative expenses, interest and capital expenditures. The amount of interest expense and general and administrative expenses that can be charged are limited based on the amounts that were previously expensed prior to repayment of the Loans. The NPI is earned based on amounts borrowed under the Credit Agreement. As of the Funding Date, a NPI of 6.5% of the net profits, as defined under the NPI Agreement, has been earned. The Agent will earn up to an additional 2.5% of the net profits pro rata for any subsequent borrowing by American Shale under the $47.5 million contingent commitment. At June 30, 2014, the company recorded a discount related to the NPI of $3,339,376 on proved property and $733,034 on unproved property. The total value recorded as a discount on loan payable related to the NPI is $4,072,410.

The NPI Agreement provides the Agent with the option to sell its NPI for fair value, as defined in the NPI Agreement, alongside American Shale or Trans Energy in the event that either American Shale or Trans Energy sells interests, including partial interests, in the subject properties at a fair value for the NPI that meets or exceeds $1.5 million for each 1.0% of NPI earned by the Agent prior to such date. In such event, American Shale can also require the Agent to sell all of its NPI to American Shale (or, alternatively, to the buyer of any subject interests) for fair value. In the event of a sale of all or substantially all of the assets of American Shale, fair value is defined as the net cash received that is attributable to the equity interests of either American Shale or Trans Energy in such transaction.

The following table summarizes the components of total debt recorded on the Company s consolidated balance sheets as of June 30, 2014 and December 31, 2013:

	June 30, 2014 (unaudited)	**December 31, 2013** (audited)
ASD Credit Agreement	$	$ 50,000,000
Unamortized Original Issuance Discount - ASD		(1,235,294)
PIK Contingent Interest Expense		2,530,050

A&R Credit Agreement-February 2013		25,000,000
Termination Fee A&R		6,784,626
Termination Fee Debt Discount A&R		(3,940,659)
PIK Interest Fee-ASD		375,000
PIK Interest A&R		2,186,037
A&R Credit Agreement -December 2013		7,500,000
Other loans - related party		205,314
Other loans - vehicles	11,934	19,239
ASD Credit Agreement - Morgan Stanley Tranche A	102,500,000	
ASD Credit Agreement - Morgan Stanley PIK fee	593,750	
ASD Credit Agreement - Morgan Stanley NPI	(4,072,410)	
Total debt	$ 99,033,274	$ 89,424,313

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NOTE 7 DERIVATIVE AND HEDGING FINANCIAL INSTRUMENTS

On May 9, 2013 our subsidiary, American Shale, entered into costless collars covering approximately 85% of its expected natural gas production from wells that were considered proved developed producing (PDP) as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The costless collars consist of long put options (floor) with a strike price of $4.00 per MMBtu and offsetting short calls (ceiling) with a strike price of $4.28 per MMBtu. The aforementioned volumes are hedged beginning with the June 2013 contract and ending with the April 2015 contract. A total of 1.6 million MMBtu are hedged over this period, with monthly volumes declining from a high of approximately 207,000 MMBtu in June 2013 to 113,000 MMBtu in April 2015. The fair value of these commodity contracts was $(428,163) and $(125,773) at June 30, 2014 and December 31, 2013, respectively.

On May 21, 2014 American Shale, entered into fixed price hedges covering approximately 90% of its expected natural gas production from PDP wells as of that date. Neither oil nor natural gas liquids have been hedged, but the BTU associated with our ethane production was essentially hedged, since it is sold as part of the natural gas stream. The hedges consist of long put options (floor) with strike prices ranging between $4.38 per MMBtu to $4.06 per MMBtu. The hedges begin with the June 2014 contract and end with the December 2018 contract. A total of 13,932,171 MMBtu are hedged over this period, with monthly volumes declining from a high of 444,534 MMBtu in July 2014 to 171,940 MMBtu in November 2018. The fair value of these commodity contracts was $(2,273,191) at June 30, 2014.

The Company has a master netting agreement on the gas hedge and therefore the current asset and liability are netted on the condensed consolidated balance sheet and the non-current asset and liability are netted on the condensed consolidated balance sheet.

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The Company has netting arrangements with BP Energy Company that provide for offsetting payables against receivables from separate derivative instruments.

The following tables summarize the approximate volumes and average contract prices of contracts the Company had in place as of June 30, 2014:

Gas Collars

Contract Period	Volumes (MMBtu)	Weighted-Average Floor Price (per MMBtu)	Weighted-Average Ceiling Price (per MMBtu)
2014	1,046,420	$ 4.00	$ 4.28
2015	464,825	$ 4.00	$ 4.28
All gas collars*	1,511,245		

* Gas collars are comprised of IF Henry Hub (100%).

Contract Period	Volumes (MMBtu)	Weighted-Average Fixed Price (per MMBtu)
2014	2,860,678	$ 4.38
2015	3,578,155	$ 4.11
2016	3,002,489	$ 4.06
2017	2,495,153	$ 4.16
2018	1,995,696	$ 4.29
All gas hedges*	13,932,171	

* Gas hedges are comprised of IF Henry Hub (100%).

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As a part of the ASD Credit Agreement, we entered into a warrant agreement with Chambers which required American Shale to sell the Lenders for a total of $2 million a warrant for 19,500 shares representing 19.5% of American Shale s stock at $263.44 per share. The warrant would have contractually expired on February 28, 2015. The warrant included a put option whereby the Lenders could require American Shale to repurchase the warrant as of February 28, 2015, or earlier if certain events occur . Under the put option, American Shale would pay the excess of the fair value per share of the stock over $263.44 times the number of shares exercisable less any distributions or similar payments defined by the agreement. In certain circumstances, American Shale had the option to transfer working interest in all of its wells equal to the value of the put option instead of paying in cash. As a result of the contingent put, the warrant is accounted for as a liability with changes in its fair value reported in earnings.

On December 20, 2013, American entered into an agreement with the holders of warrants representing 19.5% of the stock of American Shale whereby American Shale agreed to purchase the warrants from the holders for $9 million. The proceeds from the increased borrowings under the A&R Credit Agreement were used to partially fund the purchase of the warrants from the holders.

The following tables detail the fair value of derivatives recorded in the accompanying balance sheets, by category:

	As of June 30, 2014			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Commodity derivative	Current assets	$	Current liabilities	$ 883,426
Commodity derivative	Noncurrent assets		Noncurrent liabilities	1,817,928
		$		$ 2,701,354

	As of December 31, 2013			
	Derivative Assets		Derivative Liabilities	
	Balance Sheet Classification	Fair Value	Balance Sheet Classification	Fair Value
Commodity derivative	Current assets	$	Current liabilities	$ 58,176
Commodity derivative	Noncurrent assets		Noncurrent liabilities	67,597
		$		$ 125,773

The table below summarizes the realized and unrealized gains and losses related to our derivative instruments for the three and six months ended June 30, 2014 and 2013.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	$ (189,506)	$ (639)	$ (450,047)	$ (639)

Realized gains (loss) on commodity derivative				
Change in fair value of commodity derivative	(2,269,930)	659,995	(2,575,581)	659,995
Change in fair value of warrant derivative liability		467,762		591,439
Total realized and unrealized gains recorded	$ (2,459,436)	$ 1,127,118	$ (3,025,628)	$ 1,250,795

These realized and unrealized gains and losses are recorded in the accompanying unaudited condensed consolidated statements of operations as derivative gains (losses).

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NOTE 8 FAIR VALUE MEASUREMENTS

The authoritative guidance establishes a hierarchy for inputs used in measuring fair value that maximizes the use of observable inputs and minimizes the use of unobservable inputs by requiring that the most observable inputs be used when available. Observable inputs are inputs that market participants would use in pricing the asset or liability developed based on market data obtained from sources independent of the Company. Unobservable inputs are inputs that reflect the Company s assumptions of what market participants would use in pricing the asset or liability developed based on the best information available in the circumstances. The hierarchy is broken down into three levels based on the reliability of the inputs as follows:

Level 1: Quoted prices are available in active markets for identical assets or liabilities;

Level 2: Quoted prices in active markets for similar assets and liabilities that are observable for the asset or liability; or

Level 3: Unobservable pricing inputs that are generally less observable from objective sources, such as discounted cash flows models or valuations.

The financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company s assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The Company s policy is to recognize transfers in and/or out of fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The valuation policies are determined by the Treasurer and are approved by the President. Fair value measurements are discussed with the Company s audit committee, as deemed appropriate. Each quarter, the inputs used in the fair value calculations are updated and management reviews the changes from period to period for reasonableness. The Company has consistently applied the valuation techniques discussed below in all periods presented.

The following table presents the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013 by level within the fair value hierarchy

	Level 1	Level 2	Level 3	Total
June 30, 2014				
ASSETS:				
Commodity contracts				
LIABILITIES:				
Commodity contracts		$ 2,701,354		$ 2,701,354
December 31, 2013				
ASSETS:				
Commodity contracts				
LIABILITIES:				
Commodity contracts		$ 125,773		$ 125,773

We use Level 2 inputs to measure the fair value of gas commodity collar derivatives. Level 2 assets consist of commodity derivative assets and liabilities (See Note 7 - Derivative and Hedging Financial Instruments). The fair value of the commodity derivative assets and liabilities is estimated by the Company using the income valuation techniques utilizing the income approach and an option pricing model, which take into account notional quantities, market volatility, market prices, contract parameters, counterparty credit risk and discount rates based on published LIBOR rates. The Company validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company s commodity derivatives.

As of December 31, 2012, the Company s warrant derivative financial instrument issued as a part of the ASD Credit Agreement were comprised of the warrants issued by the Company to purchase 19,500 shares of common stock with a put option (See Note 7 - Derivative and Hedging Financial Instruments). The warrants were valued by third parties using a binomial lattice-based valuation model and were classified as Level 3 in the fair value hierarchy. The lattice-based valuation technique was utilized because it embodies all of the requisite assumptions (including the underlying price, exercise price, term, volatility, and risk-free interest-rate) that were necessary to measure the fair value of these instruments. The Company uses data from its peers as well as from external sources in the determination of the volatility and risk free interest rates used in the fair value calculations. A sensitivity analysis is performed as well to determine the impact of the inputs on the ending fair value estimate. Estimating fair values of derivative financial instruments requires the development of significant and subjective estimates that may, and are likely to, change over the duration of the instrument due to both internal and external market factors. In addition, option-based techniques are highly sensitive to volatility assumptions. An increase in the volatility would cause an increase in the fair value of the warrants. Likewise, a decrease in the volatility would cause a decrease in the value of the Warrants.

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The significant assumptions used in the valuation of the warrant derivative liability as of December 31, 2012 were as follows:

Exercise price	$ 1.63 per share
Stock price	$ 2.89 per share
Volatility	75%
Remaining Term of Warrants	1.41 years
Risk-free interest rate	0.20%

The following table sets forth a reconciliation of changes in the fair value of financial liabilities classified as Level 3 in the fair value hierarchy:

	June 30, 2014	June 30, 2013
Balance as of beginning of period	$	$ (2,808,278)
Total realized and unrealized gains (losses)		
Included in earnings		591,439
Issuances		
Settlements		
Transfers in and out of Level 3		
Balance as of June 30	$	$ (2,216,839)
Change in unrealized gains included in earnings Relating to instruments still held as of June 30	$	$ 591,439

NOTE 9 STOCKHOLDERS EQUITY

In April 2014, we granted 21,000 shares of stock to three employees under the long-term incentive bonus program. The 21,000 shares are not performance based and vest semi-annually over a three year period. The 21,000 shares were valued at $3.90 per share of common stock using the fair value of the common stock at the date of grant and the fair value will be amortized to compensation expense semi-annually over three years.

In April 2014, we also granted 252,000 common stock options to six employees and five outside board members. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $3.80 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period.

In January 2014, Trans Energy issued 25,000 shares of common stock to Jonathan J. Corp, a related party, for the exercise of options at a price of $0.65 per share.

In January 2014, Trans Energy issued 138,331 shares of common stock to Clarence E. Smith, a 5% Beneficial owner, for the exercise of options at a price of $1.50 per share.

In December 2013, Trans Energy granted 9,000 shares of common stock to eleven employees. These shares vest immediately and the shares were valued using the fair market value of the common stock at the date of grant. During 2013, we recorded $25,650 of share-based compensation expense related to these shares.

In November 2013, Trans Energy issued 37,500 shares of common stock to Opco related to their settlement agreement.

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In May 2013, we also granted 100,000 common stock options to an outside board member. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $3.00 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period.

In February 2013, we granted 42,000 shares of stock to five employees under the long-term incentive bonus program. Of the 42,000 shares, 36,000 shares are not performance based and vest semi-annually over a three year period and 6,000 shares are performance based and vest semi-annually over a three year period, subject to ongoing employment. The 42,000 shares were valued at $2.50 per share of common stock using the fair value of the common stock at the date of grant and the fair value will be amortized to compensation expense semi-annually over three years.

In February 2013, we also granted 346,000 common stock options to seven employees and five outside board members. These options vest semi-annually over three years and have a five year term. These stock options were granted at an exercise price of $2.50 per common share and the fair value was determined using the Black Scholes option pricing model. The options are being amortized to share-based compensation expense semi-annually over the vesting period. Of the 346,000 options granted, 12,000 of the options are performance based.

The Company has computed the fair value of all options granted using the Black-Scholes option pricing model. In order to calculate the fair value of the options, certain assumptions are made regarding components of the model, including the estimated fair value of the underlying common stock, risk-free interest rate, volatility, expected dividend yield and expected option life. Changes to the assumptions could cause significant adjustments to valuation. The Company estimated a volatility factor utilizing a weighted average of comparable published volatilities of peer companies. The Company has estimated a forfeiture rate of zero as the effect of forfeitures has not been significant and the small number of option holders does not provide a reasonable basis for prediction. The Company estimates the expected term based on the average of the vesting term and the contractual term of the options. The risk-free interest rate is based on the U.S. Treasury yield in effect at the time of the grant for treasury securities of similar maturity. The fair value of all options granted by the Company for 2011 through 2014 was determined using the following assumptions:

Expected volatility	70% - 90%
Risk free interest rate	0.80% - 1.75%
Expected term (years)	3.0 - 5.0
Dividend yield	0%

As a result of the above stock and option transactions, we recorded total stock-based compensation of $284,675 and $325,800 for the three months ended June 30, 2014 and 2013, respectively and $483,216 and $635,863 for the six months ended June 30, 2014 and 2013, respectively.

Stock option activity is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life	Aggregate Fair Value
Outstanding December 31, 2012	3,640,324	$ 1.76	2.69 Years	$ 6,406,970

Granted	446,000	$	2.61		
Exercised	(30,500)	$	2.67		
Forfeited	(10,500)	$	2.35		
Expired					
Outstanding December 31, 2013	4,045,324	$	1.85	2.05 Years	$ 7,483,849
Granted	252,000	$	3.80		
Exercised	(163,331)	$	1.37		
Forfeited					
Expired					
Outstanding June 30, 2014	4,133,993	$	1.99	1.83 Years	$ 8,226,646
Exercisable at June 30, 2014	3,812,329	$	1.24		$ 4,727,288
Unvested at June 30, 2014	321,664				

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NOTE 10 EARNINGS PER SHARE

Basic net income (loss) per share is computed by dividing net income (loss) by the weighted-average number of common shares outstanding during the reporting period. The shares of restricted common stock granted to certain officers and employees of the Company are included in the computation of basic net income (loss) per share only after the shares become fully vested. Diluted net income (loss) per share of common stock includes both vested and unvested shares of restricted stock. Diluted net income (loss) per common share of stock is computed by dividing net income by the diluted weighted-average common shares outstanding. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share. As the Company had losses for the three and six month periods ended June 30, 2014 and 2013, the potentially dilutive shares were anti-dilutive and were thus not included in the net loss per share calculation.

As of June 30 2014, potentially dilutive securities included (i) 49,500 unvested shares of restricted common stock and (ii) 4,133,993 in-the-money outstanding options.

NOTE 11 BUSINESS SEGMENTS

Our principal operations consist of exploration and production through Trans Energy, American Shale and Prima, and pipeline transmission with Ritchie County Gathering Systems and Tyler Construction Company.

Certain financial information concerning our operations in different segments is as follows:

	For the Three Months Ended June 30	Exploration and Production	Pipeline Transmission	Corporate	Total
Revenue	2014	$ 8,432,592	$ 22,830	$ 1,303	$ 8,456,725
	2013	4,641,723	26,447	2,988	4,671,158
Income (Loss) from operations	2014	2,744,344	(27,472)	(1,533,174)	1,183,698
	2013	1,680,928	(1,024)	(1,536,847)	143,057
Interest expense	2014	9,673,862		896	9,674,758
	2013	3,897,557		1,071	3,898,628
Depreciation, depletion, amortization and accretion	2014	2,248,720	250		2,248,970
	2013	739,161			739,161
Property and equipment acquisitions, including oil and gas properties	2014	14,021,282		2,087	14,023,369
	2013	6,276,278		709	6,276,987

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	For the Six Months Ended June 30	Exploration and Production	Pipeline Transmission	Corporate	Total
Revenue	2014	$ 18,149,015	$ 77,619	$ 6,433	$ 18,233,067
	2013	8,215,606	61,890	2,988	8,280,484
Income (Loss) from operations	2014	7,298,948	28,855	(2,975,862)	4,351,941
	2013	2,288,186	31,529	(3,095,547)	(775,832)
Interest expense	2014	13,801,363		4,588	13,805,951
	2013	5,795,458		5,917	5,801,375
Depreciation, depletion, amortization and accretion	2014	4,360,089	606		4,360,695
	2013	1,378,556	54		1,378,610
Property and equipment acquisitions, including oil and gas properties	2014	16,008,089		2,087	16,010,176
	2013	7,654,169		5,961	7,660,130
Total assets, net of intercompany accounts:					
June 30, 2014		93,771,803	8,315		93,780,118
December 31, 2013		90,098,192	17,129		90,115,321

Property and equipment acquisitions include accrued amounts and reclassifications.

NOTE 12 - RELATED PARTY TRANSACTIONS

In November 2013, Clarence E. Smith, a 5% Beneficial Owner, issued payment to the Company in the amount of $200,000. Mr. Smith was exercising 138,331 options at a price of $1.50 per share. On January 24, 2014, Mr. Smith s stock was issued. The Company is recognizing interest since the funds were held approximately three months before the stock was actually issued. At December 31, 2013, the $205,314 due to Mr. Smith is recorded as a note payable, related party in the current liability section of the balance sheet.

During 2013 and 2014, the Company has conducted business with two companies owned by Clarence E. Smith. Work was awarded the companies after bids were sought and reviewed. The amount of payments total $32,000 and $32,000 for 2013 and 2014, respectively.

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

The following discussion will assist in the understanding of our financial position and results of operations. The information below should be read in conjunction with the consolidated financial statements, the related notes to consolidated financial statements and our 2013 Form 10-K. Our discussion contains both historical and forward-looking information. We assess the risks and uncertainties about our business, long-term strategy and financial condition before we make any forward-looking statements but we cannot guarantee that our assessment is accurate or that our goals and projections can or will be met. Statements concerning results of future exploration, development and acquisition expenditures as well as revenue, expense and reserve levels are forward-looking statements. We make assumptions about commodity prices, drilling results, production costs, administrative expenses and interest costs that we believe are reasonable based on currently available information. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control.

We intend to focus our development and exploration efforts in our West Virginia properties and utilize our attractive opportunities to expand our reserve base through continuing to drill higher risk/higher reward exploratory and development drilling in the Marcellus Shale for 2014 and beyond with new financing. We will evaluate our properties on a continuous basis in order to optimize our existing asset base. We plan to employ the latest drilling, completion, and fracturing technology in all of our wells to enhance recoverability and accelerate cash flows associated with these wells. We believe that our extensive acreage position will allow us to grow through high risk drilling in the near term.

In summary, our strategy is to increase our oil and gas reserves and production while keeping our development costs and operating costs as low as possible. We will implement this strategy through drilling exploratory and development wells from our inventory of available prospects that we have evaluated for geologic and mechanical risk and future reserve or resource potential. The success of this strategy is contingent on various risk factors, as discussed in our 2013 Form 10-K.

Results of Operations

Three months ended June 30, 2014 compared to June 30, 2013

The following table sets forth the relationship of total revenues of principal items contained in our Unaudited Condensed Consolidated Statements of Operations for the three months ended June 30, 2014 and 2013.

	Three months ended June 30,	
	2014	**2013**
Total revenues	$ 8,456,725	$ 4,671,158
Total costs and expenses	(7,272,729)	(4,528,101)
Gain (loss) on sale of assets	(298)	
Income from operations	1,183,698	143,057
Other expenses, net	(12,133,609)	(2,761,652)
Income tax		

Net loss	$ (10,949,911)	$ (2,618,595)

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The following table is a summary of revenues, volumes, and pricing for the three months ended June 30, 2014 and 2013.

Three Months Ended June 30, 2014 compared to the Three Months Ended June 30, 2013

	Three Months Ended June 30, 2014	Three Months Ended June 30, 2013	Increase/ (Decrease)	
Natural gas sales	$ 7,826,661	$ 3,805,126	$ 4,021,535	105.7%
Oil sales	$ 66,789	$ 36,180	$ 30,609	84.6%
Natural gas liquid sales	$ 539,142	$ 800,417	$ (261,275)	-32.6%
Total Oil & Gas Sales	$ 8,432,592	$ 4,641,723	$ 3,790,869	81.7%
Transportation and other revenue	$ 24,133	$ 29,435	$ (5,302)	-18.0%
Total revenue	$ 8,456,725	$ 4,671,158	$ 3,785,567	81.0%
Net Production				
Natural gas sales (MCF)	1,644,606	831,884	812,722	97.7%
Oil sales (Bbls)	827	445	383	86.1%
Natural gas liquids (gallons)	621,205	1,036,162	(414,957)	-40.0%
Natural Gas Equivalent (MCFe)	1,738,315	982,575	755,740	76.9%
Average Sales Price per Unit				
Natural Gas (MCF)	$ 4.76	$ 4.57	$ 0.19	4.2%
Oil(Bbl)	$ 80.71	$ 81.37	$ (0.66)	-0.8%
Natural gas liquids (gallons)	$ 0.87	$ 0.77	$ 0.10	13.0%
Natural Gas Equivalent (MCFe)	$ 4.85	$ 4.72	$ 0.13	2.8%

Expenses

All data presented below is derived from costs and production volumes for the relevant period indicated.

	Three Months Ended June 30, 2014	**Three Months Ended June 30, 2013**
Costs and Expenses Per MCFE of Production:		
Production Expenses	$ 1.64	$ 1.85
Production Taxes	0.40	0.38
G&A Expenses (Excluding Share-Based Compensation)	2.51	1.24
Non-Cash Shared-Based Compensation	0.13	0.33
Depletion of Oil and Natural Gas Properties	1.24	0.73
Impairment of Oil and Natural Gas Properties		
Depreciation and Amortization	0.01	0.02
Accretion of Discount on Asset Retirement Obligation		

Total revenues increased primarily due to an increase in natural gas and oil production volumes as well as an increase in natural gas and natural gas liquid (NGL) prices. The increase in natural gas and oil volumes was the result of recently drilled wells put into production. For the three months ended June 30, 2014 and 2013, respectively, we had 28 gross wells and 11.46 net wells compared to 24 gross wells and 10.08 net wells.

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Production costs increased $1,240,431 or 55% for the three months ended June 30, 2014 as compared to the same period for 2013, primarily due to an increase in natural gas liquid transportation and processing fees associated with the increased production in 2014.

Depreciation, depletion, amortization and accretion expense increase by $1,509,809 or 204% for the three months ended June 30, 2014 compared to the same period for 2013, primarily due to the increased production volumes and lower year end reserves.

Selling, general and administrative expense decreased $5,612 or for the three months ended June 30, 2014 as compared to the same period for 2013, primarily due to an decrease in legal fees.

Interest expense increased $5,776,130 or 148% for the three months ended June 30, 2014 as compared to the same period for 2013 due to recording a termination fee of $3,104,200 related to the A&R Credit Agreement, amortization of debt discount in the amount of $2,825,379 due to payoff of the Chambers loan, and a reduction in contingent interest associated with the Chambers loan. Stated interest rate was 11% for both periods until refinancing occurred, then the interest rate of the new loan in 2014 was 10%. For the three months ended June 30, 2014 the average loan balance was $93,113,567 compared to $67,860,909 for the same period in 2013.

Gain on warrant derivative for the three months ended June 30, 2014 was $0 as compared to a gain of $467,762 for the same period last year. This represents the change in value of the put option associated with our warrant derivative liability. The warrant was repurchased in December 2013.

Loss on commodity derivative for the three months ended June 30, 2014 was $2,459,436. This represents the decrease in the fair value of the gas hedges that were entered into in connection with the Morgan Stanley financing.

Net loss for the three months ended June 30, 2014 was $10,949,911 compared to a net loss of $2,618,595 for the same period of 2013. This increase in net loss is due primarily to an increase in interest expense and the loss on commodity derivatives.

Six months ended June 30, 2014 compared to June 30, 2013

The following table sets forth the relationship of total revenues of principal items contained in our Unaudited Condensed Consolidated Statements of Operations for the six months ended March 31, 2014 and 2013.

	Six months ended June 30,	
	2014	**2013**
Total revenues	$ 18,233,067	$ 8,280,484
Total costs and expenses	(14,088,223)	(9,047,529)
Gain (loss) on sale of assets	207,097	(8,787)
Income (loss) from operations	4,351,941	(775,832)
Other expenses, net	(16,830,085)	(4,535,901)
Income tax		

Net loss	$ (12,478,144)	$ (5,311,733)

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The following table is a summary of revenues, volumes, and pricing for the six months ended June 30, 2014 and 2013.

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

	Six Months Ended June 30,		Increase/ (Decrease)	
	2014	2013		
Natural gas sales	$ 15,764,426	$ 6,601,563	$ 9,162,863	138.8%
Oil sales	$ 128,091	$ 107,903	$ 20,188	18.7%
Natural gas liquid sales	$ 2,256,498	$ 1,506,140	$ 750,358	49.8%
Total Oil & Gas Sales	$ 18,149,015	$ 8,215,606	$ 9,933,409	120.9%
Transportation and other revenue	$ 84,052	$ 64,878	$ 19,174	29.6%
Total revenue	$ 18,233,067	$ 8,280,484	$ 9,952,583	120.2%
Net Production				
Natural gas sales (MCF)	3,088,910	1,540,405	1,548,506	100.5%
Oil sales (Bbls)	1615	1257	358	28.5%
Natural gas liquids (gallons)	2,088,396	2,082,105	6,291	0.3%
Natural Gas Equivalent (MCFe)	3,396,944	1,845,392	1,551,552	84.1%
Average Sales Price per Unit				
Natural Gas (MCF)	$ 5.10	$ 4.29	$ .81	18.9%
Oil(Bbl)	$ 79.30	$ 85.83	$ (6.53)	-7.6%
Natural gas liquids (gallons)	$ 1.08	$ .72	$ .36	50.0%
Natural Gas Equivalent (MCFe)	$ 5.34	$ 4.45	$ .89	20.0%

Expenses

All data presented below is derived from costs and production volumes for the relevant period indicated.

	Six Months Ended June 30,	
	2014	**2013**
Costs and Expenses Per MCFE of Production:		
Production Expenses	$ 1.68	$ 1.94
Production Taxes	0.31	0.45
G&A Expenses (Excluding Share-Based Compensation)	1.65	1.34
Non-Cash Shared-Based Compensation	0.13	0.34
Depletion of Oil and Natural Gas Properties	1.25	0.72
Impairment of Oil and Natural Gas Properties		
Depreciation and Amortization	0.01	0.02
Accretion of Discount on Asset Retirement Obligation		

Total revenues increased primarily due to an increase in natural gas, oil, and natural gas liquid (NGL) production volumes as well as an increase in natural gas and natural gas liquid (NGL) prices. The increase in natural gas, oil, and natural gas liquid (NGL) volumes was the result of recently drilled wells put into production). For the six months ended June 30, 2014 and 2013, respectively, we had 28 gross wells and 11.46 net wells compared to 24 gross wells and 10.08 net wells.

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Production costs increased $2,176,741 or 48% for the six months ended June 30, 2014 as compared to the same period for 2013, primarily due to an increase in natural gas liquid transportation and processing fees associated with the increased production in 2014 and higher ad valorem taxes.

Depreciation, depletion, amortization and accretion expense increase by $2,982,085 or 216% for the six months ended June 30, 2014 compared to the same period for 2013, primarily due to the increased production volumes and lower year end reserves.

Selling, general and administrative expense decreased $118,132 or 3% for the six months ended June 30, 2014 as compared to the same period for 2013, primarily due to an decrease in legal and professional fees.

Interest expense increased $8,004,576 or 138% for the six months ended June 30, 2014 as compared to the same period for 2013 due to recording a termination fee of $3,104,200 related to the A&R Credit Agreement, amortization of debt discount in the amount of $2,825,379 and higher contingent interest due to the higher Chambers loan balance in 2014. Stated interest rate was 11% for both periods until refinancing occurred, then the interest rate for the new loan in 2014 was 10%. For the six months ended June 30, 2014 the average loan balance was $90,352,327 compared to $67,860,909 for the same period in 2013.

Gain on warrant derivative for the six months ended June 30, 2014 was $0 as compared to a gain of $591,439 for the same period last year. This represents the change in value of the put option associated with our warrant derivative liability. The warrant was repurchased in December 2013.

Loss on commodity derivative for the six months ended June 30, 2014 was $3,025,628. This represents the decrease in the fair value of our gas hedges.

Net loss for the six months ended June 30, 2014 was $12,478,144 compared to a net loss of $5,311,733 for the same period of 2013. This increase in net loss is due primarily to an increase in interest expense, and the loss on commodity derivatives.

Liquidity and Capital Resources

Historically, we have satisfied our working capital needs with borrowed funds and the proceeds of acreage sales. At June 30, 2014, we had positive working capital of $1,508,675 compared to positive working capital of $65,897 at December 31, 2013. The increase in working capital is primarily due to an increase in accounts receivable trade and a decrease in accounts payable to drilling operator.

During the first six months of 2014, net cash used by operating activities was $1,309,225 compared to $2,854,419 of net cash used for the same period of 2013. This increase in cash flow from operations was primarily due to higher production volumes and, higher commodity prices, which were partially offset by an increase in prepaid expenses.

We expect our cash flow from operations for 2014, compared to the comparable period in 2013, to improve because of higher projected production from the drilling program due to the increase in the number of producing wells. However, if our drilling or realized commodity prices miss expectations, our cash flow provided by operations may differ materially from our expectations.

Excluding the effects of significant unforeseen expenses or other income, our cash flow from operations fluctuates primarily because of variations in oil and gas production and prices, or changes in working capital accounts and actual well performance. In addition, our oil and gas production may be curtailed due to factors beyond our control, such as downstream activities on major pipelines causing us to shut-in production for various lengths of time.

During the first six months of 2014, net cash used by investing activities was $750,633 compared to net cash used of $5,042,105 in the same period in 2013. The change was due to higher capital expenditures in 2014 that were offset by greater proceeds from the sale of assets in 2014.

During the first six months of 2014, net cash provided by financing activities was $319,126 compared to net cash provided of $24,885,979 for the same period in 2013. This change was due to the fact that we increased our loan balance by a larger amount in the first six months of 2013 than in the comparable period in 2014.

We anticipate meeting our working capital needs with revenues from our ongoing operations, particularly from our wells in Marshall, Marion, and Wetzel counties in West Virginia, and additional borrowings.

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Critical accounting policies

We consider accounting policies related to our estimates of proved reserves, accounting for derivatives, share-based payments, accounting for oil and natural gas properties, asset retirement obligations and accounting for income taxes as critical accounting policies. The policies include significant estimates made by management using information available at the time the estimates are made. However, these estimates could change materially if different information or assumptions were used. These policies are summarized in Management s Discussion and Analysis of Financial Condition and Results of Operations in our Annual Report on Form 10-K for the year ended December 31, 2013.

Forward-looking and Cautionary Statements

This report includes forward-looking statements which may relate to such matters as anticipated financial performance, future revenues or earnings, business prospects, projected ventures, new products and services, anticipated market performance and similar matters. When used in this report, the words may, will, expect, anticipate continue, estimate, project, intend, and similar expressions are intended to identify forward-looking statements regarding events, conditions, and financial trends that may affect our future plans of operations, business strategy, operating results, and our future plans of operations, business strategy, operating results, and financial position. We caution readers that a variety of factors could cause our actual results to differ materially from the anticipated results or other matters expressed in forward-looking statements. These risks and uncertainties, many of which are beyond our control, include:

- varying demand for oil and gas;
- fluctuations in price;
- competitive factors that affect pricing;
- attempts to expand into new markets;
- the timing and magnitude of capital expenditures, including costs relating to the expansion of operations;
- hiring and retention of key personnel;
- changes in generally accepted accounting policies, especially those related to the oil and gas industry; and
- new government legislation or regulation.

Any of the above factors or a significant downturn in the oil and gas industry or with the economic conditions generally, could have a negative effect on our business and on the price of our common stock.

Item 4. Controls and Procedures

We maintain disclosure controls and procedures that are designed to be effective in providing reasonable assurance that information required to be disclosed in our reports under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the U.S. Securities and Exchange Commission (SEC), and that such information is accumulated and communicated to our management to allow timely decisions regarding required disclosure.

In designing and evaluating disclosure controls and procedures, management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable, not absolute assurance of achieving the desired objectives. Also, the design of a control system must reflect the fact that there are resource constraints and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple error or mistake. The design of any system of controls is based, in part, upon certain assumptions about the likelihood of future events and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions.

As of the end of the period covered by this report, we carried out an evaluation, under the supervision and with the participation of management, including our principal executive officer and treasurer, of the effectiveness of the design and operation of our disclosure controls and procedures as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act. Based upon that evaluation, management concluded that our disclosure controls and procedures were effective to cause the information required to be disclosed by us in reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported within the time periods prescribed by SEC, and that such information is accumulated and communicated to management, including our chief executive officer and treasurer, as appropriate, to allow timely decisions regarding required disclosure.

During the period ended, there were no changes in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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PART II

Item 1. Legal Proceedings

We may be engaged in various lawsuits and claims, either as plaintiff or defendant, in the normal course of business. In the opinion of management, based upon advice of counsel, the ultimate outcome of these lawsuits will not have a material impact on our financial position or results of operations.

Certain material pending legal proceedings to which we are a party or to which any of our property is subject, is set forth below:

EQT Corporation

On May 11, 2011, we filed an action in the U.S. District Court for the Northern District of West Virginia against EQT Corporation, a Pennsylvania corporation (Trans Energy, Inc., et al. v. EQT Corporation). The action relates to our attempt to quiet title to certain oil and gas properties referred to as the Blackshere Lease, consisting of approximately 22 oil and/or gas wells on the Blackshere Lease. The defendant, EQT Corporation, has filed with the Court an answer and counterclaim wherein it claims it holds title to the natural gas within and underlying the Blackshere Lease. On November 26, 2012, the Court granted our motion for summary judgment and denied the defendant s motions for declaratory judgment and summary judgment. On February 25, 2014, the United States Court of Appeals for the Fourth Circuit in Richmond Virginia affirmed the summary judgment motion of the U.S. District Court for the Northern District of West Virginia. The defendant s time to appeal this judgment has passed, so this judgment in our favor is final.

On June 12, 2013, EQT Production Company filed a quiet title action in the Circuit Court of Wetzel County, West Virginia. The action relates to a quiet title action relating to a 1,314 acre lease in Wetzel County, West Virginia known as the Robinson lease. On February 28, 2014, the presiding Judge issued an order granting a motion to stay this case pending appeal of the Blackshere case and the same styled case pending in the U.S. District Court of the Northern District of West Virginia.

On July 18, 2013, we filed an action in the U.S. District Court for the Northern District of West Virginia against EQT Production Company. The action relates to a quiet title action relating to a 1,314 acre lease known as the Robinson lease.

Abcouwer

On March 6, 2012, James K. Abcouwer (Abcouwer), former Chief Executive Officer of the Company, filed an action in the Circuit Court of Kanawha County, West Virginia against the Company (James K. Abcouwer vs. Trans Energy, Inc.). The action relates to the Stock Option Agreement (the Agreement) entered into between the Company and Abcouwer on February 7, 2008. By his complaint, Abcouwer alleges that the Company has breached the Agreement by not permitting Abcouwer to exercise options that are the subject of the Agreement. The Company believes that according to the terms of the Agreement all options and other rights described in the Agreement terminated ninety (90) days after the termination of Abcouwer s employment with the Company. Mr. Abcouwer is requesting an amount for his loss of the value of the stock options that are subject to the Agreement. Said amount has not been determined.

On January 14, 2013, Abcouwer filed an action in the Circuit Court of Kanawha County, West Virginia against the Company, and two individual defendants currently on the Board of Directors of the Company William F. Woodburn and Loren E. Bagley. In his complaint, Abcouwer alleges that Plaintiff and Defendants entered into a verbal agreement that required the Company to enter into a third party sales transaction which would have allegedly caused Abcouwer to make significant profit as the result of his ownership of Company stock. Abcouwer alleges that he lost approximately $30 million as a result of the fact that no sale of the Company ever took place. The Company believes that no such agreement existed and that Abcouwer s claims are wholly without merit. On March 25, 2013, the Company filed an answer denying the existence of any liability and asserting, in the alternative, counterclaims for fraud and breach of fiduciary duty. The Company s counterclaims allege that, to the extent a binding agreement between Abcouwer and the Company existed, Abcouwer failed to disclose such agreement to the Company and the SEC despite a duty to do so. Trial date has been set for November 17, 2014.

EPA

On September 28 and December 17, 2012, the U.S. Environmental Protection Agency (EPA) issued to the Company seven administrative compliance orders and a request for information. The orders and request relate to our compliance with Clean Water Act (CWA) permitting requirements at seven pond and/or well site locations in Marshall and Wetzel Counties, West Virginia and concern the alleged discharge of dredged and/or fill material into waters of the United States. The Company is actively cooperating with the EPA to resolve these matters in a timely manner. The CWA provides authority for significant civil and criminal penalties for the placement of fill in a jurisdictional stream or wetland without a permit from the Army Corps of Engineers, including for civil penalties as high as $37,500 per day per violation. Monetary civil and/or criminal penalties can be substantial for non-compliance with CWA requirements. The CWA sets forth criteria, including degree of fault and history of prior violations, which may influence CWA penalty assessments. The EPA may also seek to recover any economic benefit derived from non-compliance with the CWA.

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Resolution of the EPA s compliance orders may include monetary sanctions. However, we presently do not have sufficient information to determine whether the potential liability with respect to these matters will have a material effect on our financial position, on the results of operations, or on cash flow.

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

In April 2014, we granted 21,000 shares of stock to three employees under the long-term incentive bonus program. These shares were issued in a transaction not constituting a public offering as provided in Section 4(2) of the Securities Act of 1933.

Item 3. Defaults Upon Senior Securities

Not Applicable

Item 4. Mine Safety Disclosures

Not Applicable.

Item 5. Other Information

None.

Item 6. Exhibits

Exhibit 31.1	Certification of Principal Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit 31.2	Certification of Treasurer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
Exhibit 32.1	Certification of Principal Executive Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
Exhibit 32.2	Certification of Treasurer 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
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase
**101.DEF	XBRL Taxonomy Extension Definition Linkbase
**101.LAB	XBRL Taxonomy Extension Label Linkbase
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase

** Filed herewith.

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SIGNATURES

In accordance with the requirements of the Securities Exchange Act of 1934, the Registrant caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

		TRANS ENERGY, INC.
Date: August 14, 2014	By	/s/ John G. Corp JOHN G. CORP Principal Executive Officer
Date: August 14, 2014	By	/s/ Michael R. Guzzetta MICHAEL R. GUZZETTA Treasurer

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