UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2013

Commission file number: 001-34635

PostRock Energy Corporation

(Exact Name of Registrant as Specified in Its Charter)

Delaware (State or Other Jurisdiction of Incorporation or Organization)	27-0981065 (I.R.S. Employer Identification No.)
210 Park Avenue	
Oklahoma City, Oklahoma	73102

(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code:

(405) 600-7704

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	The NASDAQ Stock Market LLC

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 229.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer	Accelerated filer

Non-accelerated filer (Do not check if a smaller reporting company) Smaller reporting company

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

The aggregate market value of common stock held by non-affiliates of the registrant at June 28, 2013, was approximately $21.1 million, based upon the closing price of $1.53 per share as reported by the NASDAQ on such date.

The aggregate market value of outstanding common stock, including those held by affiliates of the registrant, at March 3, 2014, was approximately $40.9 million, based upon the closing price of $1.30 per share. There were 31,437,312 shares of common stock outstanding on that date.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the proxy statement for the 2014 Annual Meeting of Stockholders are incorporated by reference in Part III.

TABLE OF CONTENTS

Table of Contents

GLOSSARY

The following abbreviations are used in this report:

Bbl	Barrel
Bbls/d	Barrels per day
MMBbl	Million barrels
Mcf	Thousand cubic feet
MMcf	Million cubic feet
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
MMcf/d	Million cubic feet per day
Mcfe	Thousand cubic feet equivalent. To determine Mcfe, oil is converted on the basis of one barrel of oil equaling six Mc 1/23rd the price for a barrel of oil.
MMcfe	Million cubic feet equivalent
MMcfe/d	Million cubic feet equivalent per day
Btu	British thermal unit
MMBtu	Million British thermal units

This report contains forward-looking statements based on expectations, estimates and projections as of the date of this filing. These statements by their nature are subject to risks, uncertainties and assumptions and are influenced by various factors. As a consequence, actual results may differ materially from those expressed in the forward-looking statements. See Item 1A. “Risk Factors—Forward-Looking Statements.”

PART I

ITEM 1. BUSINESS

PostRock Energy Corporation (“PostRock”) is a Delaware corporation formed in 2009. It was formed to combine its predecessor entities, Quest Resource Corporation, Quest Energy Partners, L.P. and Quest Midstream Partners, L.P. (collectively, the “Predecessors”) into a single entity. In March 2010, PostRock completed the combination of these entities (the “Recombination”). Unless the context requires otherwise, references to “the Company,” “we,” “us” and “our” refer to PostRock from the date of the Recombination and to the Predecessors on a consolidated basis prior thereto.

Background

We are an independent oil and gas company engaged in the acquisition, exploration, development, production and gathering of crude oil and natural gas. Our primary production activity is focused in the Cherokee Basin, a 15-county region in southeastern Kansas and northeastern Oklahoma, and Central Oklahoma. We also have minor oil and gas producing properties in the Appalachian Basin. Our Cherokee Basin and Central Oklahoma properties comprise our MidContinent area of operations. We previously owned an interstate natural gas pipeline in our PostRock KPC Pipeline, LLC (“KPC”) subsidiary. KPC was sold in September 2012.

Production and Reserves

At December 31, 2013, our total assets consisted of 3,239 gross and 3,184 net wells capable of production. These wells are on approximately 361,400 net acres of leasehold, classified as developed, while we also have approximately 100,300 net acres classified as undeveloped. Our net production in 2013 totaled 14.5 Bcf of natural gas and 192,474 barrels of oil for an average of 39.8 MMcf/d of gas and 527 Bbls/d of oil. At year end, our estimated proved reserves included 86.6 Bcf of natural gas and 4.4 MMBbl of oil for a total of 113.0 Bcfe.

At December 31, 2013, our Cherokee Basin assets consisted of 2,767 gross and 2,757 net wells capable of production. These wells are on approximately 342,200 net acres of leasehold, classified as developed. In addition, we have approximately 53,100 net acres classified as undeveloped in the region. Our net production in 2013 totaled 14.0 Bcf of natural gas and 95,612 barrels of oil for an average of 38.3 MMcf/d of gas and 262 Bbls/d of oil. Our oil production in 2013 was 311% higher than our oil production in 2012. At year end, our estimated proved reserves attributable to these properties included 76.6 Bcf of natural gas and 1.3 MMBbl of oil for a total of 84.4 Bcfe.

We also have a gathering system in the Cherokee Basin. The system provides a market outlet for gas produced in an approximately 1,000 square mile area. We gather substantially all of our production in the Cherokee Basin and a minor amount of gas produced by others. At year end, throughput on the system averaged 48.7 MMcf/d of which approximately 2.2 MMcf/d and 8.2 MMcf/d was attributable to third parties and to our royalty owners, respectively. Third-party gathering contracts generally permit us to retain 20% to 30% of the sales price of the gas gathered. We believe ownership of the system is a material competitive advantage in the future development and consolidation of assets in the Cherokee Basin. The gathering system includes 63 leased compressors totaling approximately 37,537 horsepower and six CO2 amine treating facilities. The system has an estimated throughput capacity of approximately 55 MMcf/d.

At December 31, 2013, our Central Oklahoma oil assets consisted of 65 gross and 47 net wells capable of production. These wells are on approximately 10,300 net acres of leasehold, classified as developed. In addition, we have approximately 24,000 net acres classified as undeveloped in the region. During 2013, net production from these wells increased 44% to a total of 81,649 barrels of oil, or an average of 224 Bbls/d. At year end, our estimated proved reserves attributable to these properties included 1.2 Bcf of natural gas and 2.9 MMBbl of oil or 18.6 Bcfe.

At December 31, 2013, our Appalachian Basin assets consisted of 407 gross and 380 net wells capable of production. These wells are on approximately 8,900 net acres of leasehold, classified as developed. In addition, we have approximately 23,200 net acres classified as undeveloped in the region. During 2013, net production from our wells was 0.6 Bcf of natural gas and 15,214 barrels of oil for an average of 1.5 MMcf/d of gas and 42 Bbls/d of oil. At year end, our estimated proved reserves attributable to these properties included 8.8 Bcf of natural gas and 0.2 MMBbl of oil for a total of 10.0 Bcfe.

We also have a 141.1 mile gathering system in the Appalachian Basin. At December 31, 2013, this system had an average throughput of approximately 1.9 MMcf/d of which approximately 1.4 MMcf/d was attributable to our net production with the remaining 0.5 MMcf/d attributable to our royalty or joint interest owners. All of our gas produced in the area is transported by this system.

Table of Contents

Acquisitions and Divestitures

During 2013, the Company closed on three acquisitions for oil and gas properties in Central Oklahoma. The largest of the acquisitions included approximately 22,000 net acres of leasehold mineral interests, including certain producing oil and gas properties and related wells, for approximately $10.0 million. See Note 3 in Part II, Item 8 "Financial Statements and Supplementary Data" in this Annual Report Form 10-K for further discussion of the 2013 acquisitions.

During 2011, we acquired a 26.5% interest in Constellation Energy Partners ("CEP") for $17.6 million. Our interest includes the right to appoint two directors to CEP's Board. Because PostRock and CEP each have the majority of their assets in the Cherokee Basin of Kansas and Oklahoma, the investment was made in an attempt to work with CEP to explore opportunities to reduce costs and enhance value for the companies' respective investors. Except where expressly noted, references to reserves, results, production, prices and other statistics included in this Annual Report on Form 10-K exclude amounts related to our interest in CEP. At December 31, 2013 Constellation Energy Partners Management, LLC ("CEPM"), a wholly owned subsidiary of the Company and the holder of its interest in CEP, had ongoing litigation against CEP, CEP's Chief Executive Officer, Stephen R. Brunner, Richard S. Langdon, Richard H. Bachmann and John N. Seitz, each a member of the five-person CEP Board of Managers, Sanchez Oil & Gas Corporation and Sanchez Energy Partners I, LP, Antonio R. Sanchez, III and Gerald F. Willinger for conspiring to dilute CEPM's ownership interest in CEP and thereby remove CEPM's right, as the sole owner of Class A units, to select two Managers to the CEP Board of Managers. For further discussion see Note 8 of the Notes to Consolidated Financial Statements in Part II, Item 8. "Financial Statements and Supplementary Data."

On September 28, 2012, we sold KPC to MV Pipelines, LLC ("MV") for $53.5 million in cash, $53.4 million net after a working capital adjustment. MV also agreed to make additional payments of $1.0 million for each of the next four years if qualified EBITDA, as defined in the purchase agreement, of KPC for that year exceeds a target amount.

On December 24, 2010, we entered into an agreement with Magnum Hunter Resources Corporation ("MHR") to sell to MHR certain oil and gas properties and related assets located in West Virginia. The sale closed in three phases for $44.6 million. The first phase closed in December 2010 for $28 million, and the next two phases closed in January and June 2011 for a combined $16.6 million.

Financial information and revenues from external customers are located in Part II, Item 8 "Financial Statements and Supplemental Data" in this Annual Report on Form 10-K.

Description of Production Properties and Projects

Properties

We produce conventional oil in addition to coal bed methane (“CBM”) gas out of our properties in the Cherokee Basin which is situated between the Forest City Basin to the north, the Arkoma Basin to the south, the Ozark Dome to the east and the Nemaha Ridge to the west. The Cherokee Basin is a mature producing area with respect to conventional oil producing reservoirs such as the Bartlesville and other Pennsylvanian age sandstones, which were initially discovered and developed beginning in the early 1900s.

The principal gas formations targeted include the Mulky, the Weir-Pittsburgh and the Riverton. These coal seams are blanket type deposits, which extend across large areas of the Cherokee Basin. Each seam is generally two to five feet thick. Additional minor coal seams such as the Summit, Bevier, Fleming and Rowe are found at varying locations. These seams range in thickness from one to two feet.

CBM is considered an “unconventional resource” in that the coal seam serves as both the source rock and the reservoir rock. The storage mechanism is also different. Gas is stored in the pore or void space of the rock in conventional gas, but in CBM, most, and frequently all, of the gas is stored by adsorption. This adsorption leads to gas being stored at relatively low pressures. Gas flow can be increased by reducing the reservoir pressure. Frequently, the coal bed pore space, which is in the form of cleats or fractures, is filled with water. The reservoir pressure is reduced by pumping out the water, allowing methane to “desorb” from the coal and flow through the cleat structure to the well bore. Because of the necessity to remove water and reduce the pressure within the coal seam, CBM, unlike most conventional hydrocarbons, often will not produce significant gas immediately on initial production testing. Coal bed formations typically require extensive dewatering and de-pressuring before desorption can occur and the methane begins to flow at commercial rates. The ability to flow gas and water to the wellbore in a CBM well is determined by the fracture or cleat network in the coal. While these fractures, at shallow depths of less than 500 feet, are sometimes open enough to produce the fluids naturally, at greater depths the networks are progressively squeezed shut, reducing the ability to flow naturally. It is necessary to provide other avenues of flow, such as hydraulically fracturing the coal seam. By pumping fluids at high pressure, fractures are opened in the coal.

Table of Contents

A slurry of water, certain chemicals and sand is pumped at high pressures into the fractures, with the sand essentially propping the fractures open. After the release of pressure, the flow of both water and gas is improved, allowing the production of gas.

Our Central Oklahoma area of focus encompasses much of seven counties. At present, our production is located in Seminole and Pottawatomie counties. The majority of the Company's current production is from the Hunton carbonate; however, we also produce from other reservoirs including the Woodford, Viola, Redfork, and Wilcox. We also have non-producing leasehold in Payne, Lincoln, Cleveland, McClain and Garvin counties. Oil has been produced in the region since the early 1900s from multiple horizons including the Hunton, Viola, Wilcox, Arbuckle, Redfork, and Woodford shale. In all, at least 18 different geologic horizons are productive regionally. Producing depths range from less than 1,000 feet to 6,000 feet. There are numerous opportunities in the region to apply modern drilling, completion and operating technology to enhance recovery from reservoirs, such as the Hunton carbonate among others, that have produced historically and also to develop unconventional reservoirs, like the Woodford and Mississippian. Our plans include vertical and horizontal drilling and completion techniques.

The Appalachian Basin is one of the largest and oldest producing basins in the United States. Our main area of operation in the Appalachian Basin is West Virginia, where our producing formations range in depth from 1,500 feet to approximately 6,500 feet. Our main production formations are the lower Devonian Marcellus Shale, the shallow Mississippian (Big Injun, Maxton, Berea, Pocono, Big Lime) and the Upper Devonian (Riley, Benson, Java, Alexander, Elk, Cashaqua, Middlesex, West River and Genesee, including the Huron Shale member and Rhinestreet Shales).

Projects

Our 2013 exploration and development capital expenditures totaled $40.0 million. Included in the $40.0 million, we successfully completed 152 new wells and recompleted 62 wells in the Cherokee Basin, completed three new wells and recompleted nine wells in Central Oklahoma, and recompleted a well in the Appalachian Basin. Our development activity in 2013 was directed toward increasing oil production and reserves in response to the low natural gas price environment. As a result of oil focused development, oil production in 2013 increased 101% over the prior year to 192,474 barrels while oil reserves increased from 2.7 MMBbl at year-end 2012 to 4.4 MMBbl at year-end 2013.

One of our most significant projects has been to reconfigure our entire compression system in the Cherokee Basin. This program was piloted with a proof of concept phase in 2012 and began to be fully implemented in 2013. We expect the project to be complete in the first half of 2014. The project is expected to cost approximately $8.2 million, with roughly $5.5 million of the project cost in 2014, and result in compression rental savings of approximately $3.2 million per year and to reduce fuel use of about 2.5 MMcf/d as compared to what it was prior to the project.

Our focus for 2014 will continue to be on growing the percentage of oil included in our production and reserves through development, leasing, and opportunistic acquisitions. We have budgeted approximately $15.0 million for exploration and developmental drilling with the majority of our budget focused on horizontal oil wells in Central Oklahoma. If attractive opportunities arise, additional capital may be directed towards further oil development in Central Oklahoma. We intend to fund our 2014 capital expenditures with cash flow from operations and availability under our credit facility.

Oil and Gas Data

Preparation of Reserve Reports

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that our reserve estimation is prepared and reported in accordance with rules and regulations promulgated by the Securities Exchange Commission (“SEC”) as well as established industry practices used by independent engineering firms and our peers. These internal controls include, but are not limited to: 1) documented process workflow timeline, 2) verification of economic data inputs to information supplied by our internal operations accounting, regional production and operations, land, and marketing groups, and 3) senior management review of internal reserve estimations prior to publication.

Cawley, Gillespie & Associates, Inc. (“CGA”) prepared our reserve estimates at December 31, 2011, 2012 and 2013. CGA is an independent firm of petroleum engineers, geologists, geophysicists and petro-physicists; they do not own any interest in our properties and are not employed on a contingent fee basis. The technical person responsible for our reserve estimates at CGA meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Table of Contents

Estimated Reserves

The following tables present our estimated net proved reserves based on our reserve reports, and the prices used to determine those reserves. The reserves table does not include CEP's reserves. Proved reserves are those quantities of oil and gas, which, by analysis of geo-scientific and engineering data, can be estimated with reasonable certainty to be economically producible, from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations and prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The data was prepared by CGA. Reserve pricing for the periods presented, seen in the table below, was determined by averaging the first day of the month price for the twelve months of the respective fiscal year.

	2011	2012	2013
Crude oil price per Bbl	$ 96.19	$ 95.05	$ 96.94
Natural gas price per MMBtu	$ 4.12	$ 2.76	$ 3.67

	Gas (Bcf)	Oil (MMBbl)	Total (Bcfe)	%
December 31, 2011				
Developed	117.4	1.0	123.7	99 %
Undeveloped	0.8	0.0	1.0	1 %
Total proved reserves	118.2	1.0	124.7	100 %
December 31, 2012				
Developed	69.7	1.8	80.5	94 %
Undeveloped	—	0.9	5.3	6 %
Total proved reserves	69.7	2.7	85.8	100 %
December 31, 2013				
Developed	85.0	2.7	101.2	90 %
Undeveloped	1.6	1.7	11.8	10 %
Total proved reserves	86.6	4.4	113.0	100 %

The following table presents our proportionate share of proved reserves of CEP's continuing operations. These reserve amounts are based on publicly available data and not subject to our internal controls described above. The Company has updated the previously filed amounts for December 31, 2012 related to CEP as discontinued operations have now been presented in their current public filing. Since December 31, 2011 amounts were not publicly available these amounts do not reflect the changes from discontinued operations.

	Gas (Bcf)	Oil (MMBbl)	Total (Bcfe)
December 31, 2011			
Developed	39.3	0.2	40.3
Undeveloped	12.4	0.1	12.9
Total proved reserves	51.7	0.3	53.2
December 31, 2012			
Developed	9.4	0.2	10.6
Undeveloped	0.4	0.1	1.0
Total proved reserves	9.8	0.3	11.6
December 31, 2013			
Developed	14.2	0.4	16.6
Undeveloped	2.4	0.1	3.0
Total proved reserves	16.6	0.5	19.6

As disclosed above, we used a price of $3.67 per MMBtu, representing a first-day-of-month, twelve-month average price, to determine our natural gas reserves at December 31, 2013.

Reserve estimates are imprecise and may change as additional information becomes available. Furthermore, estimates of natural gas and oil reserves are projections based on geo-scientific and engineering data. There are uncertainties inherent in the interpretation of this data as well as the projection of future rates of production and the timing of development expenditures. Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of natural gas and oil that

Table of Contents

cannot be measured in an exact way. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. See Item 1A. “Risk Factors—Risks Related to Our Business—Our estimated reserves are based on many assumptions that may prove to be inaccurate.” Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

At December 31, 2013, we had 11.8 Bcfe of proved undeveloped reserves. During 2013, we spent approximately $7.9 million to develop 63 wells that were previously reported as proved undeveloped reserves in 2012, all of which were oil, as we directed our capital spending during the year toward oil projects. At December 31, 2013, we did not have material proved undeveloped reserves that remain undeveloped five years subsequent to their disclosure as proved undeveloped reserves. All of our proved undeveloped reserves included in our 2013 reserve report are scheduled to be developed before 2018.

Production Volumes, Sales Prices and Production Costs

The following table sets forth information regarding our producing properties. The production figures reflect the net production attributable to our revenue interest and are not indicative of the total volumes produced by the wells. All sales data excludes the effects of our derivative financial instruments, unless otherwise indicated.

	Year Ended December 31,		
	2011	2012	2013
Net Production	($ in thousands)		
Gas (Bcf)	18.3	16.4	14.5
Oil (Bbls)	78,087	95,863	192,474
Gas equivalent (Bcfe)	18.8	17.0	15.7
Oil and Natural Gas Sales			
Gas sales	$ 72,812	$ 43,911	$ 51,489
Oil sales	7,075	8,640	18,200
Total sales	$ 79,887	$ 52,551	$ 69,689

	Year Ended December 31,		
	2011	2012	2013
Average Sales Price - Unhedged			
Gas ($ per Mcf)	$ 3.98	$ 2.68	$ 3.55
Oil ($ per Bbl)	$ 90.60	$ 90.13	$ 94.56
Gas equivalent ($ per Mcfe)	$ 4.25	$ 3.10	$ 4.45
Average Sales Price - Hedged (1)			
Gas ($ per Mcf)	$ 5.84	$ 7.15	$ 3.38
Oil ($ per Bbl)	$ 84.93	$ 89.77	$ 95.38
Gas equivalent ($ per Mcfe)	$ 6.04	$ 7.41	$ 4.30
Operating Expenses ($ per Mcfe)			
Production costs (2)	$ 2.09	$ 2.22	$ 2.24
Production taxes (3)	$ 0.41	$ 0.27	$ 0.32
Net Revenue ($ per Mcfe)	$ 1.75	$ 0.61	$ 1.89

(1)Data includes the effects of our commodity derivative contracts that do not qualify for hedge accounting.

(2)Includes lease operating and gathering costs.

(3)Production taxes include severance and ad valorem taxes.

Table of Contents

The following table presents realized gains and losses on our commodity derivative financial instruments:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Realized Gain (Loss) on Derivative Financial Instruments			
Gas hedges (1)	$ 34,135	$ 73,196	$ (2,429)
Oil hedges	(443)	(34)	158
Total	$ 33,692	$ 73,162	$ (2,271)

____

(1)2012 includes $30.2 million received from exiting above-market natural gas swap contracts originally scheduled for delivery in 2013.

The following table presents our production, average sales prices and production costs by area for the years ended December 31, 2011, 2012 and 2013:

	Cherokee Basin			Central Oklahoma			Appalachia		
	2011	2012	2013	2011	2012	2013	2011	2012	2013
Production									
Natural gas (Bcf)	17.6	15.8	14.0	0.1	—	—	0.6	0.6	0.5
Oil (Bbls)	12,987	23,285	95,612	49,278	56,649	81,649	15,822	15,930	15,214
Total production (Bcfe)	17.7	16.0	14.6	0.4	0.3	0.5	0.7	0.7	0.6
Avg Sales Price - Unhedged									
Natural gas (per Mcf)	$ 3.94	$ 2.66	$ 3.52	$ 4.76	$ 2.95	$ 3.37	$ 5.05	$ 3.29	$ 4.24

Oil (per Bbl)	$ 85.00	$ 86.05	$ 92.81	$ 92.86	$ 91.96	$ 96.44	$ 88.20	$ 89.55	$ 95.44
Total average sales price (per Mcfe)	$ 3.98	$ 2.76	$ 3.99	$ 13.48	$ 15.25	$ 15.94	$ 6.37	$ 4.98	$ 5.96
Production Costs (per Mcfe)	$ 2.05	$ 2.13	$ 2.19	$ 6.25	$ 5.92	$ 4.46	$ 1.87	$ 2.30	$ 1.72

Productive Wells

The following tables set forth information regarding our ownership of wells at December 31, 2011, 2012 and 2013. Our data is comprised of all producing wells and wells mechanically capable of production.

	Gas		Oil		Total	
	Gross (1)	Net (2)	Gross (1)	Net (2)	Gross (1)	Net (2)
December 31, 2011	3,223	3,178	62	59	3,285	3,238
December 31, 2012	2,948	2,910	93	84	3,041	2,993
December 31, 2013	2,945	2,910	294	274	3,239	3,184

(1)Gross wells are the sum of all wells in which we own an interest.

(2)Net wells are gross wells multiplied by our fractional interests in the well.

Table of Contents

Acreage Statistics

The following table sets forth our developed and undeveloped lease and mineral acreage at December 31, 2011, 2012 and 2013.

	Acreage (1)					
	Developed		Undeveloped		Total	
	Gross (2)	Net (3)	Gross (2)	Net (3)	Gross (2)	Net (3)
December 31, 2011	367,200	356,200	147,500	142,400	514,700	498,600
December 31, 2012	363,200	351,300	99,700	96,200	462,900	447,500
December 31, 2013	372,700	361,400	137,100	100,300	509,800	461,700

(1)Includes acreage in the states of Kansas, Oklahoma, West Virginia, and New York.

(2)Gross acres are an approximation of the sum of all acres in which we own interest.

(3)Net acres are approximated gross acres multiplied by our fractional interest on the acreage.

At December 31, 2013, we had approximately 342,200 net developed and 53,100 net undeveloped acres in the Cherokee Basin, approximately 10,300 net developed and 24,000 net undeveloped acres in Central Oklahoma, and approximately 8,900 net developed and 23,200 net undeveloped acres in the Appalachian Basin. Developed acres are acres spaced or assigned to productive wells/units based upon governmental authority or standard industry practice. Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas, regardless of whether such acreage contains proved reserves.

Drilling Activities

Our drilling, recompletion, abandonment and acquisition activities for the periods indicated are shown below. This information includes wells in all areas in the period in which they were completed.

	Year Ended December 31,					
	2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells drilled						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Development wells drilled						
Productive	116	116	18	18	155	155
Dry	—	—	—	—	13	13
Wells plugged and abandoned	(1)	(1)	—	—	(15)	(15)
Wells divested	—	—	—	—	—	—
Wells acquired	—	—	—	—	58	45
Net increase in capable wells	115	115	18	18	211	198
Recompletion of producing wells	49	49	103	103	72	72

During 2013, we plugged and abandoned 42 wells, 27 of which were inactive and not capable of producing during the entire period of our ownership of the wells. We also acquired two wells that were plugged by the previous owner and are not included in the table above. As of the date of filing, there has been no drilling activity for the year.

Exploration and Production

General

As the operator of wells in which we have an interest, we design and manage the development of these wells and supervise operation and maintenance activities on a day-to-day basis. We employ production and reservoir engineers, geologists and other specialists.

Field operations conducted by our personnel include duties performed by “production techs” or employees whose primary responsibility is to operate the wells. Other field personnel are experienced and involved in the activities of well servicing, the development and completion of new wells and the construction of supporting infrastructure for new wells (such as electric service,

Table of Contents

disposal wells and gas well flow lines). The primary equipment we own includes trucks, well service rigs, stimulation assets and construction equipment. At times we utilize third-party contractors to supplement our field personnel.

In the Cherokee Basin, we provide, on an in-house basis, many of the services required for the completion and maintenance of our CBM wells. Internally sourcing these functions significantly reduces our reliance on third-party contractors, which typically provide these services. We believe that we are able to realize significant cost savings because we can reduce delays in executing our plan of development and avoid paying price markups. We currently rely on third-party contractors to drill our wells. Once a well is drilled, either we or a third-party contractor run the casing. We perform the cementing, fracturing and the majority of stimulation in completing our own wells. In Central Oklahoma and the Appalachian Basin, we rely entirely on third-party contractors for these completion services.

Leases

At December 31, 2013, we had approximately 9,800 leases covering approximately 461,700 net acres. The typical oil and gas lease provides for the payment of royalties to the mineral owner for all oil or gas produced from any well drilled on the lease premises. This amount ranges from 12.5% to 20.0% resulting in an 80.0% to 87.5% net revenue interest to us.

Because the acquisition of oil and natural gas leases is a very competitive process, and involves certain geological and business risks to identify productive areas, prospective leases are sometimes held by other operators. In order to gain the right to drill these leases, we may purchase leases from them.

In the Cherokee Basin, at year end, we held leases on approximately 395,300 net acres, of which 12,200 net acres are not currently held by production. In Central Oklahoma we held leases on approximately 34,400 net acres, of which 24,100 net acres are not currently held by production. Unless we establish commercial production on the properties subject to these leases during their term, these leases will expire. Leases in the Cherokee Basin and Central Oklahoma covering approximately 9,500 and 4,800 net acres, respectively, are scheduled to expire before December 31, 2014 unless developed, extended or renewed. If these leases expire, we will lose the right we currently have to develop the related properties.

In the Appalachian Basin, we hold oil and natural gas leases and development rights by virtue of farm-out agreements or similar mechanisms on 17,967 net acres that are still within their original lease or agreement term and are not earned or are not held by production. Unless we establish commercial production on the properties or fulfill the requirements specified by the various leases or agreements, during the prescribed time periods, these leases or agreements will expire.

Marketing and Major Customers

During 2013, approximately 83% of our MidContinent gas production was sold to BP Energy Company and approximately 47%, 28% and 24% of our MidContinent oil production was sold to Sunoco Partners Marketing & Terminals L.P., Holly Frontier Refining & Marketing LLC and Coffeyville Resources Refining & Marketing, LLC, respectively. Approximately 87% of our 2013 Appalachian Basin gas production was sold to South Jersey Resources Group. All of our oil production in the Appalachian Basin was sold to BD Oil Gathering.

If we were to lose any of these purchasers, we believe that we would be able to promptly replace them because we believe there are multiple options for marketing our commodities. The physical location of our production provides ample options for marketing the commodities to creditworthy parties.

Commodity Derivative Activities

Prices for crude oil and natural gas are affected by a variety of factors beyond our control and can be volatile. When commodity futures prices have been at appropriate levels we have used derivative instruments to reduce commodity price uncertainty and increase cash flow predictability inherent to the marketing of our production. For additional information about our derivatives, see Part I, Item 1A. “Risk Factors—Our commodity price risk management activities may prevent us from benefiting fully from price increases and may expose us to other risks” and Part II, Item 7A. “Quantitative and Qualitative Disclosures About Market Risk.”

Competition

We operate in a highly competitive environment for acquiring properties, marketing our production and employing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. As a result, our competitors may be able to pay more for properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects

Table of Contents

and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in our industry.

Title

Production Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved developed reserves. Prior to the commencement of development operations on those properties, we conduct a title examination and perform curative work with respect to significant defects that we discover. To the extent title opinions or other investigations reflect title defects on properties, we are typically responsible for curing any title defects at our expense. We generally will not commence development operations on a property until we have cured any material title defects that we discover on such property. We believe that we have satisfactory title to our material producing properties in accordance with standards generally accepted in our industry.

In some cases, title to these properties is subject to encumbrances, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry. We believe, however, that no such liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties, our interest therein, or their use in the operation of our business. In some cases, lands over which leases have been obtained are subject to prior liens which have not been subordinated to the leases. We believe, however, that we have obtained sufficient right-of-way grants and permits from public authorities and private parties in order to operate our business in all material respects.

Pipeline Rights-of-Way

Substantially all of our gathering systems are constructed within rights-of-way granted by property owners named in the appropriate land records. All of our compressor stations are located on property owned in fee or on property obtained via long-term leases or surface easements.

Our property or rights-of-way are subject to encumbrances, restrictions and other imperfections. These imperfections have not interfered, and we do not expect that they will materially interfere, with the conduct of our business. In many instances, lands over which rights-of-way have been obtained are subject to prior liens which have not been subordinated to the right-of-way grants. In some cases, not all of the owners named in the appropriate land records have joined in the right-of-way grants, but in substantially all such cases signatures of the owners of majority interests have been obtained. Substantially all permits have been obtained from public authorities to cross over or under, or to lay facilities in or along, water courses, county roads, municipal streets, and state highways, where necessary. Substantially all permits have also been obtained from railroad companies to cross over or under lands or rights-of-way, many of which are also revocable at the grantor's election.

Certain of our rights to lay and maintain pipelines are derived from recorded oil and natural gas leases for wells that are currently in production; however, the leases are subject to termination if the wells cease to produce. In most cases, the right to maintain existing pipelines continues in perpetuity, even if the well associated with the lease ceases to be productive. In addition, because some of these leases affect wells at the end of lines, these rights-of-way will not be used for any other purpose once the related wells cease to produce.

Seasonality

In the past, freezing weather and storms in the winter and flooding in the spring and summer have resulted in a number of our wells being off-line for a short period of time sometimes for many consecutive days. This adversely affects our production volumes and revenues and increases our lease operating costs due to the time spent by field employees to bring the wells back on-line. This has also resulted in wells producing at lower rates for extended periods after returning to production. We have recently had success managing this exposure by using products that limit freezing on wells and compressors and using heavy equipment to facilitate faster access to wells in inclement weather to return them to production after outages.

Government Regulation

Exploration for, and production and marketing of, crude oil and natural gas are extensively regulated by a number of federal, state and local governmental authorities under various laws and regulations governing a wide variety of matters, including allowable rates

Table of Contents

of production, plugging of abandoned wells, transportation, prevention of waste and pollution, protection of the environment and worker health and safety. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and/or criminal penalties, the imposition of injunctive relief or both.

These laws are under constant review for amendment or expansion. Moreover, the possibility exists that new legislation or regulations may be adopted. Amended, expanded or new laws and regulations increasing the regulatory burden on the crude oil and natural gas industry can have a significant impact on our operations or our customers' ability to use natural gas and may require us or our customers to change their operations significantly or incur substantial costs. Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the US Environmental Protection Agency ("EPA"), the Federal Energy Regulatory Commission ("FERC"), the Commodity Futures Trading Commission ("CFTC"), other federal and state regulatory agencies and the courts. We cannot predict when or whether any such proposals may become effective. In the past, the natural gas industry has been heavily regulated. In view of the many uncertainties with respect to current and future laws and regulations, including their applicability to us, we cannot predict the overall effect of such laws and regulations on our future operations.

Management believes that our operations comply in all material respects with applicable laws and regulations and that the existence and enforcement of such laws and regulations have no more restrictive effect on our method of operations than on other similar companies in the energy industry. We have internal procedures and policies that we believe help to ensure that our operations are conducted in substantial regulatory compliance. Governmental regulations applicable to our operations include those relating to worker safety, environmental matters, exploration and production activities, natural gas gathering pipelines and natural gas sales.

Environmental Matters

Our operations are subject to various, increasingly stringent federal, state and local laws and regulations relating to the emission, release and discharge of materials into, and the protection of, the environment and the protection of natural resources and wildlife and the imposition of liability for pollution. We have made and will continue to make expenditures in our efforts to comply with these requirements. We do not believe that we have, to date, expended material amounts in connection with such activities or that compliance with these requirements will have a material adverse effect on our capital expenditures, earnings or competitive position. Although such requirements do have a substantial impact on the oil and gas industry, to date, we do not believe they have affected us to any greater or lesser extent than other companies in the industry. Due to the size of our operations, significant new environmental regulation could have a disproportionate adverse effect on our operations. Failure to comply with these laws and regulations or newly adopted laws or regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders limiting or enjoining future operations or imposing additional compliance requirements or operational limitations on our business. See Part I, Item 1A. Risk Factors—"We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental and operational safety regulations or an accidental release of hazardous substances into the environment"; "We may face unanticipated water and other waste disposal costs"; and "Recent and future environmental laws and regulations may significantly limit, and increase the cost of, our exploration, production and gathering operations."

Production

Federal, state and local regulations apply to our exploration and production activities and impose permitting, bonding and reporting requirements. Most states, and some counties and municipalities, in which we operate also regulate the location and method of drilling and casing of wells, the surface use and restoration of properties upon which wells are drilled, the plugging and abandoning of wells; and/or notice to surface owners and other third parties. Some state laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states allow forced pooling or integration of tracts to facilitate exploration while others rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and reduce our interest in the unitized properties. In addition, some state conservation laws establish maximum rates of production from oil and gas wells. These laws generally prohibit venting or flaring of gas and impose requirements regarding the ratability of production. Moreover, some states impose a production or severance tax on the production and sale of oil, gas and gas liquids within its jurisdiction.

The Cherokee Basin has been an active producing region for a number of years. Many of our properties had abandoned oil and conventional gas wells on them at the time the current lease was entered. A number of these wells remain unplugged or were improperly plugged by a prior landowner or operator. Many of the former operators of these wells have ceased operations and cannot be located or do not have the financial resources to plug these wells. We believe that we are not responsible for plugging an abandoned well on one of our leases, unless we have used, attempted to use or invaded the abandoned well bore in our operations on the land or have otherwise agreed to assume responsibility for plugging the wells. While the Kansas Corporation Commission's ("KCC") current interpretation of Kansas law is consistent with our position, it could change in the future.

Table of Contents

Regulation of Gathering Pipelines

Our gathering pipeline operations are currently limited to the States of Kansas, Oklahoma, and West Virginia. State regulation of gathering facilities generally includes various permitting, safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. We are licensed as an operator of a natural gas gathering system with the KCC and are required to file periodic information reports with it. We are not required to be licensed as an operator or to file reports in Oklahoma and West Virginia.

On those portions of our gathering system that are open to third-party producers, the producers have the ability to file complaints challenging our gathering rates, terms of services and practices. We have contracts with all of the third-party producers for which we gather gas and are not aware of any complaints being filed. Our fees, terms and practices must be just, reasonable, not unjustly discriminatory and not unduly preferential. If the KCC or the Oklahoma Corporation Commission ("OCC"), as applicable, were to determine that the rates charged to a complainant did not meet this standard, the KCC or the OCC, as applicable, would have the ability to adjust our rates with respect to the wells subject to the complaint. We are not aware of any instance in which either the KCC or the OCC has made such a determination in the past.

These regulatory burdens may affect profitability and management is unable to predict the future cost or impact of complying with such regulations. While state regulation of pipeline transportation does not materially affect our operations, we do own several small, discrete delivery laterals in Kansas that are subject to a limited jurisdiction certificate issued by the KCC. State regulation of pipeline transportation may influence certain aspects of our business and the market price for our products.

Our natural gas gathering pipeline facilities are generally exempt from FERC's jurisdiction and regulation pursuant to Section 1(b) of the Natural Gas Act of 1938 ("NGA"), which exempts pipeline facilities that perform primarily a gathering function, rather than a transportation function. However, if FERC were to determine that the facilities perform primarily a transmission function rather than a gathering function, these facilities may become subject to regulation as interstate natural gas pipeline facilities which may subject us to fines and additional costs and regulatory burdens that would substantially increase our operating costs and adversely affect our profitability. See Part I, Item 1A. Risk Factors—"A change in the jurisdictional characterization of some of our gathering assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our gathering assets, which may indirectly cause our revenues to decline and operating expenses to increase."

Sales of Natural Gas

The price at which we buy and sell natural gas currently is not subject to federal regulation or, for the most part, state regulation, other than those regulations that prohibit certain practices, such as price manipulation, in the sale of natural gas. Our sales of natural gas are affected by the availability, terms and cost of pipeline transportation. As noted above, the price and terms of access to pipeline transportation are subject to extensive regulation. FERC is continually proposing and implementing new rules and regulations affecting those segments of the natural gas industry, most notably interstate natural gas transmission companies that remain subject to FERC’s jurisdiction. These initiatives may affect the intrastate transportation of natural gas under certain circumstances. The stated purpose of many of these regulatory changes is to promote competition among the various sectors of the natural gas industry. We cannot predict the ultimate impact of these regulatory changes to our natural gas marketing operations.

Employees

At December 31, 2013, we had 152 field employees in offices located in Kansas, Oklahoma and West Virginia, and 57 executive and administrative personnel located at our headquarters in Oklahoma City. None of our employees are covered by a collective bargaining agreement and management considers its relations with employees to be satisfactory.

Where To Find Additional Information

Additional information about us can be found on our website at www.pstr.com. Information on our website is not part of this document. We also provide, free of charge on our website, our filings with the SEC, including our annual reports, quarterly reports and current reports, along with any amendments thereto, as soon as reasonably practicable after we have electronically filed such material with, or furnished it to, the SEC.

You may also find information related to our corporate governance, board committees and company code of ethics at our website. Among the information you can find there is the following:

•Audit Committee Charter;

Table of Contents

- Compensation Committee Charter;

- Nominating, Corporate Governance, Safety and Environment Committee Charter; and

- Code of Business Conduct and Ethics.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Energy prices are very volatile, and if commodity prices are depressed or decline, our revenues, profitability and cash flows will be adversely affected.

The prices we receive for our oil and gas production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil and gas are commodities; therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Although we have recently focused our development efforts on crude oil, approximately 92.6% of our production in 2013 was natural gas. The prices that we receive for our production, and the levels of our production, depend on a variety of factors that are beyond our control, such as:

- the levels and location of oil and gas supply and demand and expectations regarding supply and demand, including the potential long-term impact of an abundance of natural gas from shale on the global natural gas supply;

- price and level of foreign imports of oil and gas;

- level of consumer product demand;

- weather conditions;

•overall domestic and global economic conditions;

•political and economic conditions in oil and gas producing countries, including embargoes and continued hostilities in the Middle East and other sustained military campaigns, acts of terrorism or sabotage;

•actions of the Organization of Petroleum Exporting Countries and other state-controlled oil companies relating to oil price and production controls;

•the impact of the U.S. dollar exchange rates on oil and gas prices;

•technological advances affecting energy consumption;

•governmental regulations and taxation;

•the impact of energy conservation efforts;

•the costs, proximity and capacity of gas pipelines and other transportation facilities; and

•the price and availability of alternative fuels.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and gas, and a drop in prices will significantly affect our financial results and impede our growth. In particular, declines in commodity prices will:

•reduce the amount of cash flow available for capital expenditures, including the drilling of wells and the construction of infrastructure to transport the hydrocarbons produced;

•negatively impact the value of our reserves because declines in oil and gas prices would reduce the amount of oil and gas we can produce economically;

•reduce the drilling and production activity of our third-party customers and increase the rate at which our customers shut in wells; and

Table of Contents

•limit our ability to borrow money or raise additional capital.

We may be required to write-down the carrying value of our assets.

Lower oil and gas prices may not only decrease our revenues, profitability and cash flows, but also reduce the amount of oil and gas that we can produce economically. This may result in our having to make substantial downward adjustments to our estimated reserves. Substantial decreases in oil and gas prices have rendered and may continue to render a significant number of our planned exploration and development projects uneconomic. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write-down, as a non-cash charge to earnings, the carrying value of our oil or gas properties.

We are exposed to credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our customers, vendors and other counterparties. Some of our customers, vendors and counterparties may be highly leveraged and subject to their own operating and regulatory risks. Despite our credit review and analysis, we may experience financial losses in our dealings with these and other parties with which we enter into transactions as a normal part of our business activities. Any nonpayment or nonperformance by our customers, vendors or counterparties could have a material adverse impact on our consolidated financial position, results of operations or cash flows.

We are unable to pass through all of our costs and expenses for gathering and compression to royalty owners under our gas leases, which reduces our net income and cash flows.

We incur costs and expenses for gathering, dehydration, treating and compression of the gas that we produce. The terms of some of our existing gas leases and other development rights currently do not, and the terms of some of the gas leases and other development rights that we may acquire in the future may not, allow us to charge the full amount of these costs and expenses to the royalty owners under the leases or other agreements. During 2011, we reached settlements of several royalty owner lawsuits in Oklahoma and Kansas. These lawsuits were related, in part, to the amounts previously deducted by us to cover the costs and expenses for gathering and compression. As a result of these settlements, we are charging post-production costs to royalty and overriding royalty interest owners pursuant to an agreed upon formula. To the extent that we are unable to charge and recover the full amount of these costs and expenses from our royalty owners, our net income and cash flows will be reduced.

Unless we replace the reserves that we produce, our existing reserves and production will decline, which would adversely affect our revenues, profitability and cash flows.

Producing oil and gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and gas reserves, production and cash flow depend on our success in developing and exploiting our reserves efficiently and finding or acquiring additional recoverable reserves economically. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs or production from our existing wells could decline at a faster rate than we have estimated, which would adversely affect our business, financial condition and results of operations. Factors that may hinder our ability to acquire additional reserves include competition, access to capital, prevailing gas prices and attractiveness of properties for sale.

Our estimated reserves are based on assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

It is not possible to measure underground accumulations of oil and gas in an exact way. Reserve estimation is a subjective process that involves estimating volumes to be recovered from underground accumulations of oil and gas that cannot be directly measured and assumptions concerning future oil and gas prices, production levels and operating and development costs. In estimating our level of oil and gas reserves, we and our independent reserve engineers make certain assumptions that may prove to be incorrect, including assumptions relating to:

•a constant level of future oil and gas prices;

•geological conditions and expected reservoir characteristics based on geological, geophysical and engineering assessments;

•production levels;

•capital expenditures;

Table of Contents

- operating and development costs;
- the effects of governmental regulations and taxation; and
- availability of funds.

If these assumptions prove to be incorrect, our estimates of reserves, the economically recoverable quantities of oil and gas attributable to any particular group of properties, the classifications of reserves based on risk of recovery and our estimates of the future net cash flows from our reserves could change significantly. Additionally, there has been increased debate and disagreement over the classification of reserves, with particular focus on proved undeveloped reserves. Changing interpretations of the classification standards or disagreements with our interpretations could cause us to write-down reserves.

Our standardized measure is calculated using unhedged oil and gas prices and is determined in accordance with the rules and regulations of the SEC. The present value of future net cash flows from our estimated proved reserves is not necessarily the same as the market value of our estimated proved reserves. The estimated discounted future net cash flows from our estimated proved reserves is based on twelve month average prices and expected costs in effect on the day of estimate. The timing and amount of actual future prices and costs, which affect the present value of the reserves, may be higher or lower than the timing and amounts at the time of the estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows in compliance with the Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) Topic 932, Extractive Activities—Oil and Gas, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and gas industry in general.

Drilling for and producing oil and gas is a costly and high-risk activity with many uncertainties that could adversely affect our financial condition or results of operations.

Our drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. The cost of drilling, completing and operating a well is often uncertain, and cost factors, as well as the market price of oil and gas, can adversely affect the economics of a well. Furthermore, our drilling and producing operations may be curtailed, delayed or canceled as a result of other factors, including:

•high costs, shortages or delivery delays of drilling rigs, equipment, labor or other services;

•adverse weather conditions;

•difficulty disposing of water produced as part of our production process;

•equipment failures or accidents;

•title problems;

•pipe or cement failures or casing collapses;

•compliance with environmental and other governmental requirements;

•environmental hazards, such as gas leaks, oil spills, pipeline ruptures and discharges of toxic gases;

•lost or damaged oilfield drilling and service tools;

•loss of drilling fluid circulation;

•unexpected operational events and drilling conditions;

•increased risk of wellbore instability due to horizontal drilling;

•pressure or irregularities in formations;

•unusual or unexpected geological formations;

Table of Contents

•natural disasters, such as fires and floods;

•blowouts, surface craterings and explosions; and

•uncontrollable flows of oil, gas or well fluids.

A productive well may become uneconomic in the event water or other harmful substances are encountered, which impair or prevent the production of oil or gas from the well. In addition, production from any well may be unmarketable if it is contaminated with water or other harmful substances. We may drill wells that are unproductive or, although productive, do not produce oil or gas in economic quantities. Unsuccessful drilling activities could result in higher costs without any corresponding revenues. Furthermore, a successful completion of a well does not ensure a profitable return on the investment.

Our commodity price risk management activities may prevent us from benefiting fully from price increases and may expose us to other risks.

To the extent that we engage in risk management activities to protect ourselves from commodity price fluctuations, we may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

•our production falls short of the hedged volumes;

•a sudden unexpected event materially impacts oil and natural gas prices;

•the counterparties to our hedging or other price risk management contracts fail to perform under those arrangements; and

•there is a widening of price-basis differentials between delivery points for our production and the delivery point assumed in the hedge arrangement.

The Dodd-Frank Act and implementing regulations could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

In 2010, the President signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”). Among other things, the Dodd-Frank Act requires the CFTC and the SEC to enact regulations affecting derivative contracts, including the derivative contracts we use to hedge our exposure to price volatility through the over-the-counter market.

The CFTC and SEC have adopted several regulations implementing the Dodd-Frank Act and are considering several additional proposed regulations. For example, the CFTC has issued final rules requiring centralized clearing of certain categories of swaps and is considering expanding this requirement to additional swap categories, including commodity swaps. We could be required either to clear our swap transactions or claim an exemption from clearing for swaps used for hedging purposes. In addition, the CFTC has proposed regulations implementing position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents (with exemptions for certain bona fide hedging transactions). The impact of such regulations upon our business is not yet clear. Certain of our hedging and trading activities and those of our counterparties may be subject to the position limits, which may reduce our ability to enter into hedging transactions.

While it is not possible at this time to predict when the CFTC will finalize certain other related rules and regulations, the Dodd-Frank Act and related regulations may require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with our derivative activities, although whether these requirements will apply to our business is uncertain at this time. If the regulations ultimately adopted require that we post margin for our hedging activities or require our counterparties to hold margin or maintain capital levels, the cost of which could be passed through to us, or impose other requirements that are more burdensome than current regulations, our hedging would become more expensive and we may decide to alter our hedging strategy.

The Dodd-Frank Act and implementing regulations may significantly increase the cost of derivative contracts (including through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, restrict our flexibility in conducting trading and hedging activity and increase our exposure to less creditworthy counterparties. If we reduce our use of derivative contracts as a result of the new requirements, our results of operations may become more volatile and cash flows less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural-gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower

Table of Contents

commodity prices. Any of these consequences could have a material adverse effect on our consolidated financial position, results of operations or cash flows.

Because of our lack of asset and geographic diversification, adverse developments in our operating areas would adversely affect our results of operations.

A substantial portion of our assets are located in the Cherokee Basin. As a result, our business is disproportionately exposed to adverse developments affecting this region. Potential adverse developments could result from, among other things, changes in governmental regulation, capacity constraints with respect to the pipelines connected to our wells, curtailment of production, natural disasters or adverse weather conditions in or affecting these regions. Due to our lack of diversification in asset type and location, an adverse development in our business or this operating area would have a significantly greater impact on our financial condition and results of operations than if we maintained more diverse assets and operating areas.

Our business involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, our operations and financial results could be adversely affected.

There are a variety of risks inherent in our operations that may generate liabilities, including contingent liabilities, and financial losses to us, such as:

•damage to wells, pipelines, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters and acts of terrorism;

•inadvertent damage from construction, farm and utility equipment;

•leaks of gas or oil spills as a result of the malfunction of equipment or facilities;

•fires and explosions; and

•other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any of these or other similar occurrences could result in the disruption of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution, impairment of our operations and substantial revenue losses.

We are not fully insured against all risks, including drilling and completion risks that are generally not recoverable from third parties or insurance. We do not have property insurance on any of our underground pipeline systems or wellheads that would cover damage to the pipelines. Pollution and environmental risks generally are not fully insurable. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable costs and on commercially reasonable terms. Premiums and deductibles for certain insurance policies have increased substantially in recent years. Due to these cost increases, we may not be able to obtain the levels or types of insurance we would otherwise have obtained, and the insurance coverage we do obtain may contain large deductibles or fail to cover certain hazards or cover all potential losses. Losses and liabilities from uninsured and underinsured events and delay in the payment of insurance proceeds could have a material adverse effect on our business, financial condition and results of operations.

We remain highly leveraged.

At December 31, 2013, we had $101.6 million of contractual commitments outstanding, consisting of debt service requirements and non-cancelable operating lease and purchase obligation commitments. Of such amount, $92.0 million was outstanding under our $200 million secured borrowing base revolving credit facility with a current borrowing base of $115 million.

Our ability to borrow funds will depend upon a number of factors, including the condition of the financial markets. Under certain circumstances, the use of leverage may create a greater risk of loss to stockholders than if we did not borrow. The risk of loss in such circumstances is increased because we would be obligated to meet fixed payment obligations on specified dates regardless of our cash flow. If we do not make our debt service payments when due, our lenders may foreclose on assets securing such debt.

Our future level of debt could have important consequences, including the following:

Table of Contents

•our ability to obtain additional debt or equity financing, if necessary, for drilling, expansion, working capital and other business needs may be impaired or such financing may not be available on favorable terms;

•a substantial decrease in our revenues as a result of lower oil and gas prices, decreased production or other factors could make it difficult for us to pay our liabilities. Any failure by us to meet these obligations could result in litigation, non-performance by contract counterparties or bankruptcy;

•our funds available for operations and future business opportunities will be reduced by that portion of our cash flow required to make principal or interest payments on our debt;

•we may be more vulnerable to competitive pressures or a downturn in our business or the economy generally; and

•our flexibility in responding to changing business and economic conditions may be limited.

Our ability to service our debt will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our indebtedness, we will be forced to take actions such as reducing or delaying business activities, acquisitions, investments and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness or seeking additional equity capital. We may not be able to affect any of these remedies on satisfactory terms or at all.

Our credit agreement has substantial restrictions and financial covenants that restrict our business and financing activities.

The operating and financial restrictions and covenants in our credit agreement restrict our ability to finance future operations or capital needs and to engage, expand or pursue our business activities. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by our results of operations and financial conditions and events or circumstances beyond our control. If market or other economic conditions do not improve, our ability to comply with these covenants may be impaired. If we violate any of the restrictions, covenants, ratios or tests in our credit agreement, our indebtedness may become immediately due and payable, the interest rates on our credit agreement may increase and the lenders' commitment, if any, to make further loans to us may terminate. We might not have, or be able to obtain, sufficient funds to make these accelerated payments in which event we may be forced to file for bankruptcy.

For a description of our credit facility, please read Part II, Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Agreement” and Note 10 in Part II, Item 8.

An increase in market interest rates will cause our debt service obligations to increase.

Borrowings under our credit agreement bear interest at floating rates. The rates are subject to adjustment based on fluctuations in market interest rates. An increase in the interest rates associated with our floating-rate debt would increase our debt service costs and affect our results of operations and cash flow. In addition, an increase in our interest expense could adversely affect our future ability to obtain financing or materially increase the cost of any additional financing.

We may not be able to obtain funding at all, or to obtain funding on acceptable terms, because of the deterioration of the credit and capital markets. This may hinder or prevent us from meeting our future capital needs.

In recent years, global financial markets and economic conditions experienced disruptions and volatility, which caused deterioration in the credit and capital markets. A recurrence of similar conditions in the future could make it difficult for us to obtain funding for our ongoing capital needs.

In volatile financial markets, the cost of raising money in the debt and equity capital markets can fluctuate widely and the availability of funds from those markets may diminish significantly. Our ability to access certain capital markets such as the market for high yield debt may be limited due to our size. The difficult financial environment may also limit the number of prospects for potential joint venture, asset monetization, or other capital raising transactions that we may pursue in the future or reduce the values we are able to realize in those transactions. As a result of these factors, we cannot be certain that funding will be available if needed and to the extent required, on acceptable terms. If we cannot meet our capital needs, we may be unable to implement our development plan, enhance our existing business, complete acquisitions or otherwise take advantage of business opportunities or respond to competitive pressures, any of which could have a material adverse effect on our production, revenues and results of operations.

Table of Contents

Strategic determinations, including the allocation of capital and other resources to strategic opportunities, are challenging, and our failure to appropriately allocate capital and resources among our strategic opportunities may adversely affect our financial condition and reduce our growth rate.

Our future growth prospects are dependent upon our ability to identify optimal strategies for our business. In developing our business plan, we considered allocating capital and other resources to various aspects of our businesses including well-development (primarily drilling), reserve acquisitions, exploratory activity, corporate items and other alternatives. We also considered our likely sources of capital. Notwithstanding the determinations made in the development of our 2014 budget, business opportunities not previously identified periodically come to our attention, including possible acquisitions and dispositions. If we fail to identify optimal business strategies, or fail to optimize our capital investment and capital raising opportunities and the use of our other resources in furtherance of our business strategies, our financial condition and growth rate may be adversely affected. Moreover economic or other circumstances may change from those contemplated by our 2014 budget, and our failure to recognize or respond to those changes may limit our ability to achieve our objectives.

Our ability to produce oil and gas could be impaired if we are unable to acquire adequate supplies of water.

The recent drought, which began in 2011 and covered 80% of the contiguous United States with at least abnormally dry conditions, may impair our ability to obtain the water required for our drilling operations as government officials ration water supplies crucial to energy exploration. In the hardest-hit areas, water-management districts have warned residents and businesses to curtail usage from rivers, lakes and aquifers. The shortage is forcing exploration and production companies to buy water from farmers, irrigation districts and municipalities and is increasing the cost of the water. Our inability to locate sufficient amounts of water at reasonable prices could adversely impact our operations, particularly with respect to our Central Oklahoma oil producing properties.

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

If an examination of the title history of a property reveals that an oil or gas lease or other developed rights has been purchased in error from a person who is not the owner of the mineral interest desired, our interest would substantially decline in value. In such an instance, the amount paid for such lease or leases or other developed rights would be lost. It is management's practice, in acquiring leases, or undivided interests in leases or other developed rights, not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we will rely upon the judgment of lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease or other developed rights in a specific mineral interest.

Prior to drilling a well, however, it is the normal practice in the industry for the person or company acting as the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such curative work entails expense. The work might include obtaining affidavits of heirship or causing an estate to be administered. Our failure to obtain these rights may adversely impact our ability in the future to increase production and reserves.

A change in the jurisdictional characterization of some of our gathering assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our gathering assets, which may indirectly cause our revenues to decline and operating expenses to increase.

We believe that the facilities comprising our gathering systems meet the traditional tests used by FERC to distinguish gathering facilities, which are not subject to FERC's jurisdiction under the NGA, from FERC-jurisdictional transmission facilities. The classification and regulation of some of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress. If FERC were to determine that the facilities perform primarily a transmission function, these facilities may become subject to regulation as interstate natural gas pipeline facilities and we may be subject to fines. We believe the expenses associated with compliance with FERC regulations, including seeking certificate authority for construction, service and abandonment, establishing rates and tariffs, and meeting FERC's detailed regulatory accounting and reporting requirements, if such compliance were to become necessary, would substantially increase our operating costs and would adversely affect our profitability.

FERC regulation affects our gathering systems and the markets for our natural gas. FERC's policies and practices concerning, for example, its policies on open access transportation, ratemaking, capacity release and market center promotion, could indirectly affect our gathering systems.

Although natural gas gathering facilities are exempt from FERC jurisdiction under the NGA, such facilities are subject to regulation by the state in which such facilities are located. State regulation of gathering facilities generally includes various safety,

Table of Contents

environmental and, in some circumstances, open access requirements and rate regulation. Our gathering operations are limited to the States of Kansas, Oklahoma and West Virginia. We are licensed as an operator of a natural gas gathering system with the KCC and are required to file periodic information reports with the KCC. We are not required to be licensed as an operator or to file reports in Oklahoma or West Virginia.

Our gathering operations may be or become subject to safety and operational regulations relating to the design, installation, testing, construction, operation, replacement and management of gathering facilities. In the future, legislative and regulatory changes could require us to incur additional capital expenditures and increased costs.

We may incur significant costs and liabilities in the future resulting from a failure to comply with new or existing environmental and operational safety regulations or an accidental release of hazardous substances into the environment.

We may incur significant costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and gas exploration, development, production, gathering and transportation activities. These costs and liabilities could arise under a wide range of federal, state and local environmental, health and safety laws and regulations, including regulations and enforcement policies, which have tended to become increasingly strict over time.

Our operations are subject to stringent and complex environmental laws and regulations. Failure to comply with these or future laws and regulations or may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders limiting or enjoining future operations or imposing additional compliance requirements or operational limitations. Certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances or hydrocarbons have been disposed or otherwise released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment.

There is inherent risk of environmental costs and liabilities in our business due to our handling of oil and natural gas, air emissions related to our operations, and historical industry operations and waste disposal practices. For example, an accidental release from one of our pipelines could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may not be able to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase our compliance costs and the cost of any remediation that may become necessary.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our gas production operations. Productive zones frequently contain water that must be removed in order for the gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce gas in commercial quantities. The produced water must be transported from the lease and injected into disposal wells. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

In the event (1) water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, (2) our wells produce water in excess of the applicable volumetric permit limits, (3) the disposal wells fail to meet the requirements of all applicable regulatory agencies, or (4) we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

•we cannot obtain future permits from applicable regulatory agencies;

•water of lesser quality or requiring additional treatment is produced;

•our wells produce excess water;

•new laws and regulations require water to be managed or disposed in a different manner; or

•costs to transport the produced water to the disposal wells increase.

Table of Contents

The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous solid wastes. EPA has delegated the authority to administer RCRA, in whole or in part to individual states, which also can impose their own, more stringent requirements. Our operations generate some ordinary industrial wastes, such as paint wastes, waste solvents, and waste oils, which may be regulated as hazardous wastes. The transportation of natural gas in pipelines may also generate some hazardous wastes subject to RCRA or comparable state laws. Drilling fluids, produced waters, and most other wastes associated with the exploration, development, production and transportation of oil and gas are currently excluded from regulation as hazardous wastes under RCRA but may be regulated by EPA or state agencies as non-hazardous solid wastes. Moreover, it is possible that this exclusion could change and cause some or all of such wastes now to be classified as hazardous wastes, which could increase our waste management costs and could have a material adverse effect on our results of operations and financial position.

Recent and future environmental laws and regulations may significantly limit, and increase the cost of, our exploration, production and gathering operations.

Recent and future environmental laws and regulations, including additional federal and state restrictions on greenhouse gas emissions ("GHG") in response to climate change concerns, may increase our capital and operating costs and also reduce the demand for the oil and natural gas we produce. The oil and gas industry is a direct source of certain GHG emissions, such as carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. The EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule, which required certain sources and other facilities that emit 25,000 metric tons or more of carbon dioxide equivalent per year to begin collecting GHG emissions data under a new reporting system as of January 1, 2010. In November 2010, the EPA issued final regulations requiring the annual reporting of GHG emissions from qualifying facilities in the upstream oil and natural gas sector, including onshore production (Subpart W). Although the Mandatory Reporting Rule does not control GHG emission levels from any facilities, it has caused us to incur monitoring and reporting costs for emissions subject to the rule. In addition, relatively large sources of GHG emission are subject to permitting requirements, which could be expanded in the future to include smaller sources.

Federal or state legislative or regulatory initiatives that regulate or restrict emissions of GHGs in areas in which we conduct business, as well as private legal actions brought under common law theories for alleged climate change impacts, could adversely affect the demand for our products and could increase the costs of our operations, including costs to operate and maintain our facilities, obtain and comply with permits, install new emission controls on our facilities, acquire allowances to authorize our GHG emissions, pay any taxes related to our GHG emissions and/or administer and manage a GHG program. Reductions in our revenues or increases in our expenses as a result of climate legislative and regulatory initiatives or litigation could have a material adverse effect on our business.

Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. We may incur expenditures in the future for air pollution control equipment in connection with obtaining or maintaining permits and approvals for air emissions.

The Endangered Species Act ("ESA"), restricts activities that may affect endangered or threatened species or their habitats. The designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans or limit future development activity in the affected areas.

Federal legislation and state legislative and regulatory initiatives relating to oil and gas operations, including hydraulic fracturing, could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. We routinely employ hydraulic fracturing in our drilling activity. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. The process is typically regulated by state oil and natural gas commissions; however, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the Safe Drinking Water Act "SDWA". On February 11, 2014, the EPA released guidance and an interpretative memorandum clarifying that SDWA permit requirements apply to hydraulic fracturing activities using diesel fuels and indicating EPA's intent to make decisions on such permitting on a case-by-case basis. In addition, Congress has considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic-fracturing process. Moreover, on November 23, 2011, the EPA announced that it was granting in part a petition to initiate a rulemaking under the Toxic Substances Control Act, relating to chemical substances and mixtures used in oil and gas exploration and production. Further, on May 24, 2013 the U.S. Department of the Interior published a proposed rule in the Federal Register that includes disclosure requirements and other mandates for hydraulic fracturing on federal lands.

Table of Contents

State legislatures and agencies are also enacting legislation and promulgating rules to regulate hydraulic fracturing and require disclosure of hydraulic fracturing chemicals. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

There are certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. These on-going or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms. President Obama created the Interagency Working Group on Unconventional Natural Gas and Oil by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

Further, on April 17, 2012, the EPA issued final rules that subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAPS”) programs. The rules establish specific new requirements for emissions from compressors, controllers, dehydrators, storage tanks, gas processing plants and certain other equipment and include NSPS standards for completions of hydraulically fractured natural gas wells. Until January 1, 2015, these standards require owners/operators to reduce Volatile Organic Compound emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the gas and make it available for use or sale, which can be done through the use of green completions. Since promulgating final rules, the EPA has reconsidered aspects of them and litigation challenging the rules is ongoing. We are currently evaluating the effect these rules could have on our business and believe that these rules could result in increased operating costs.

Increased regulation and attention given to the hydraulic-fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic-fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale plays, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Certain U.S. federal income tax preferences currently available with respect to oil and natural gas production may be eliminated as a result of future legislation.

The Obama administration's most recent budget proposal and other recently proposed legislation have included the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production. If enacted into law, these proposals would eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Proposed changes to such tax incentives include, but are not limited to (1) the repeal of the percentage depletion allowance for oil and gas properties, (2) the elimination of current deductions for intangible drilling and development costs, (3) the elimination of the deduction for U.S. production activities and (4) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred in connection with the exploration for or development of, oil and gas within the United States. It is unclear whether any such changes will be enacted or how soon any such changes would become effective. The passage of any legislation as a result of these proposals or any other similar changes in U.S. federal income tax laws could negatively affect our consolidated financial position, results of operations or cash flows.

Our ability to grow and to increase our profitability may depend in part on our ability to make acquisitions. Acquisitions are subject to a number of risks.

Our ability to grow and increase our profitability may depend in part on our ability to make acquisitions that result in an increase in our net income per share and cash flows. We may be unable to make such acquisitions because we are: (1) unable to identify attractive acquisition candidates or negotiate acceptable purchase contracts with them, (2) unable to obtain financing for these acquisitions on economically acceptable terms or (3) outbid by competitors. If we are unable to acquire properties containing proved reserves, our total level of proved reserves will decline as a result of our production, which will adversely affect our results of operations. Even if we do make acquisitions that we believe will increase our net income per share and cash flows, these acquisitions may perform below our expectations and nevertheless result in a decrease in net income and/or cash flows.

Our acquisitions may involve number risks, including:

Table of Contents

- operating a larger combined organization and adding operations;
- difficulties in assimilating and operating the assets and operations of the acquired business, particularly if the assets acquired are in a new geographical area;
- risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- loss of significant key employees from the acquired business;
- diversion of management's attention from other business concerns;
- failure to realize expected profitability or growth;
- failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

If third-party pipelines and other facilities interconnected to our gas pipelines become unavailable to transport or produce gas, our revenues and cash flows could be adversely affected.

We depend upon third-party pipelines and other facilities that provide delivery options to and from our pipelines and facilities for the benefit of our customers. Since we do not own or operate any of these pipelines or other facilities, their continuing operation is not within our control. If any of these third-party pipelines and other facilities become unavailable to transport or produce gas, our revenues and cash flows could be adversely affected.

We do not own all of the land on which our pipelines are located or on which we may seek to locate pipelines in the future, which could disrupt our operations and growth.

We do not own the land on which our pipelines have been constructed, but we do have right-of-way and easement agreements from landowners and governmental agencies, some of which require annual payments to maintain the agreements and most of which have a perpetual term. New pipeline infrastructure construction may subject us to more onerous terms or to increased costs if the design of a pipeline requires redirecting. Such costs could have a material adverse effect on our business, results of operations and financial condition.

In addition, the construction of additions to the pipelines may require us to obtain new rights-of-way prior to constructing new pipelines. We may be unable to obtain such rights-of-way to expand pipelines or capitalize on other attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way. If the cost of obtaining new rights-of-way increases, our business and results of operations could be adversely affected.

Risks Related to the Ownership of Our Common Stock

The price of our common stock has been and may continue to experience volatility.

The price of our common stock has been and may continue to be volatile. In addition to the risk factors described above, some of the factors that could affect the price of our common stock are quarterly increases or decreases in revenue or earnings, changes in revenue or earnings estimates by the investment community, sales of our common stock by significant stockholders, short-selling of our common stock by investors, issuance of a significant number of shares for equity-based compensation or to raise additional capital to fund our operations, changes in market valuations of similar companies and speculation in the press or investment community about our financial condition or results of operations, as well as any doubt about our ability to continue as a going concern. General market conditions and U.S. or international economic factors and political events unrelated to the performance of us may also affect our stock price. For these reasons, investors should not rely on recent trends in the price of our common stock to predict the future price of our common stock or our financial results.

Table of Contents

Our charter and bylaws contain provisions that may make it more difficult for a third party to acquire control of us, even if a change in control would result in the purchase of our stockholders' common stock at a premium to the market price or would otherwise be beneficial to our stockholders.

There are provisions in our restated certificate of incorporation and bylaws that may make it more difficult for a third party to acquire control of us, even if a change in control would result in the purchase of our stockholders' common stock at a premium to the market price or would otherwise be beneficial to our stockholders. For example, our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, provisions of our restated certificate of incorporation and bylaws, including limitations on stockholder actions by written consent and on stockholder proposals and director nominations at meetings of stockholders, could make it more difficult for a third party to acquire control of us. Delaware corporation law may also discourage takeover attempts that have not been approved by our board of directors.

White Deer Energy L.P. and its affiliates ("White Deer") beneficially own approximately 60%, as of March 3, 2014, of our common stock after giving effect to the exercise of their outstanding warrants, giving White Deer control in corporate transactions and other matters, including a sale of our Company, as well as potentially diluting the profits of the Company.

At March 3, 2014, including 10,958,601 common shares owned and 20,161,351 warrants, White Deer beneficially owns 31,119,952 shares, or approximately 60%, of our common stock. By exercising their warrants, White Deer can benefit from their respective percentage of all of our profits and growth. In addition, we have agreed to issue White Deer additional warrants on each quarterly dividend payment date of the Series A Preferred Stock prior to December 31, 2014, on which dividends are not paid in cash but instead accrue. The voting power of the Series B Preferred Stock issued with certain of the warrants is limited to 45% of the votes applicable to all outstanding voting stock. In addition, White Deer may vote any shares of common stock held by it without regard to that limit.

As a result of its ownership, White Deer is our controlling stockholder and is able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other stockholders, the outcome of certain corporate transactions or other matters submitted to our stockholders for approval, including, for example, potential mergers or acquisitions, asset sales and other significant corporate transactions. The interests of White Deer may not coincide with the interests of other holders of our common stock.

Subject to certain restrictions, White Deer may make investments in companies that compete with us. In addition, our interests may conflict with those of White Deer with respect to, among other things, business opportunities that may be presented to White Deer and to our directors associated with White Deer.

Substantial sales of our common stock by White Deer could cause our stock price to decline.

We are unable to predict whether significant amounts of our common stock will be sold by White Deer. Any sales of substantial amounts of our common stock in the public market by White Deer, or the perception that these sales might occur, could lower the market price of our common stock.

Forward-Looking Statements

Various statements in this report, including those that express a belief, expectation, or intention, as well as those that are not statements of historical fact, are forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. These statements include those regarding projections and estimates concerning the timing and success of specific projects; financial position; business strategy; budgets; amount, nature and timing of capital expenditures; drilling of wells and construction of pipeline infrastructure; acquisition and development of oil and gas properties and related pipeline infrastructure; timing and amount of future production of oil and gas; operating costs and other expenses; estimated future net revenues from oil and gas reserves and the present value thereof; cash flow and anticipated liquidity; funding of our capital expenditures; ability to meet our debt service obligations; and other plans and objectives for future operations.

When we use the words “believe,” “intend,” “expect,” “may,” “will,” “should,” “anticipate,” “could,” “estimate,” “plan,” “pred their negatives, or other similar expressions, the statements which include those words are usually forward-looking statements. When we describe strategy that involves risks or uncertainties, we are making forward-looking statements. The factors impacting these risks and uncertainties include, but are not limited to:

•current weak economic conditions;

Table of Contents

•volatility of oil and gas prices;

•increases in the cost of drilling, completion and gas gathering or other costs of developing and producing our reserves;

•our debt covenants;

•access to capital, including debt and equity markets;

•results of our hedging activities;

•drilling, operational and environmental risks; and

•regulatory changes and litigation risks.

You should consider carefully the statements in Part I, Item 1A. "Risk Factors" and other sections of this Annual Report on Form 10-K, which describe factors that could cause our actual results to differ from those set forth in the forward-looking statements.

We have based these forward-looking statements on our current expectations and assumptions about future events. The forward-looking statements in this report speak only as of the date of this report; we disclaim any obligation to update these statements unless required by securities law, and we caution you not to rely on them unduly. Readers are urged to carefully review and consider the various disclosures made by us in our reports filed with the SEC, which attempt to advise interested parties of the risks and factors that may affect our business, financial condition, results of operation and cash flows. If one or more of these risks or uncertainties materialize, or if the underlying assumptions prove incorrect, our actual results may vary materially from those expected or projected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

We have described our properties, reserves, acreage, wells, production and drilling activity in Part I, Item 1. “Business” of this Annual Report on Form 10-K, which is incorporated by reference herein in response to this Item. A substantial portion of our assets are pledged to collateralize our secured credit facilities. See Note 10 in Part II, Item 8. “Financial Statements and Supplementary Data.”

Administrative Facilities

Our corporate headquarters office space located at 210 Park Avenue, Oklahoma City, Oklahoma 73102 is leased. The office lease is for 10 years expiring August 31, 2017, and covers approximately 35,000 square feet.

We own two buildings in Chanute, Kansas and one in Lenapah, Oklahoma, for our MidContinent operations.

We lease approximately 1,500 square feet of office space on a month-to-month basis for field personnel in Harrisville, West Virginia.

ITEM 3. LEGAL PROCEEDINGS

We are subject, from time to time, to certain legal proceedings and claims in the ordinary course of conducting our business. We will record a liability related to our legal proceedings and claims when we have determined that it is probable that we will be obligated to pay and the related amount can be reasonably estimated, and we will disclose the related facts in the notes to our financial statements, if material. If we determine that an obligation is reasonably possible, we will, if material, disclose the nature of the loss contingency and the estimated range of possible loss, or include a statement that no estimate of loss can be made. Like other oil and gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. Therefore, it is extremely difficult to reasonably quantify future environmental related expenditures. For further discussion of lawsuits and related contingencies, see Note 14 in Part II, Item 8. “Financial Statements and Supplementary Data.”

The trial set in Delaware of CEPM's suit against Constellation Energy Partners, LLC and Sanchez Energy Partners I, LP, et al. has been postponed indefinitely based on an anticipated settlement. While nothing has yet been finalized, the proposed settlement

Table of Contents

contemplates the Company recovering a target of $21.6 million by way of the sale of all of its A Units to CEP and Sanchez, followed by the orderly disposition of its Class B Units in a combination of a sale or sales to Sanchez and various blocks or other market transactions in the course of 2014. The settlement as currently proposed would eliminate all disputes between the parties and position the Company to redeploy its capital into oil-focused development projects primarily in Central Oklahoma. While there can be no assurance of success, it is hoped that the settlement will be finalized in early 2014. For further discussion see Note 8 in Part II, Item 8. "Financial Statements and Supplementary Data."

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5.MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information

Our common stock is listed on the NASDAQ Stock Market LLC under the symbol "PSTR." The table below presents the intraday high and low price for each quarter for the prior two fiscal years.

Quarter Ended	High	Low
2012		
March 31	$ 4.00	$ 2.82
June 30	$ 3.10	$ 1.33
September 30	$ 2.68	$ 1.34
December 31	$ 1.88	$ 1.25
2013		
March 31	$ 2.20	$ 1.45
June 30	$ 1.81	$ 1.22

September 30	$ 2.10	$ 1.08
December 31	$ 1.65	$ 1.11

The closing price of our common stock on March 3, 2014 was $1.30 per share. At March 3, 2014, there were 31,437,312 shares of common stock outstanding held of record by approximately 405 stockholders. Warrants to purchase 20,161,351 shares of our common stock at a weighted average exercise price of $1.54 per share were outstanding and held by White Deer. Warrants to purchase 224,608 shares of our common stock at an exercise price of $7.57 per share were outstanding and held by Constellation Energy Group ("CEG").

Dividends

The payment of dividends on our common stock is within the discretion of the board of directors and is dependent upon many factors. We have not declared any dividends on our common stock and do not anticipate paying any dividends on our common stock in the foreseeable future. Our credit facility contains restrictions on our ability to pay dividends.

Issuer Purchases of Equity Securities

None.

ITEM 6. SELECTED FINANCIAL DATA

We have derived the following selected consolidated financial information for PostRock as of December 31, 2012, and 2013 and for the years ended December 31, 2011, 2012, and 2013 from the audited consolidated financial statements of PostRock included in Part II, Item 8. "Financial Statements and Supplementary Data." We have derived the selected consolidated financial information of PostRock as of December 31, 2010 and 2011 and from March 6 to December 31, 2010, and of our Predecessors as of December 31, 2009 and for the period from January 1 to March 5, 2010, and the year ended December 31, 2009, from PostRock's and the Predecessors' audited consolidated financial information included in its SEC filings.

	Predecessors					
	Year Ended December 31, 2009	January 1 to March 5, 2010	March 6 to December 31, 2010	Year Ended December 31, 2011	2012	2013
	(in thousands, except per share data)					
Statement of Operations Data						
Revenues						
Oil and gas sales	$ 79,893	$ 18,659	$ 69,277	$ 79,887	$ 52,551	$ 69,689
Gathering	7,760	1,076	4,771	5,239	2,444	2,611
Total	87,653	19,735	74,048	85,126	54,995	72,300
Costs and expenses						
Production expense	55,961	8,645	38,329	47,136	42,213	40,085
General and administrative	38,006	5,458	17,682	16,005	14,810	15,990
Litigation reserve	1,030	—	1,640	11,592	—	—
Depreciation, depletion and amortization	39,438	3,574	15,835	24,088	27,669	27,369
(Gain) loss on disposal of assets	25	—	(13,572)	(10,557)	295	(194)
Impairment of assets	215,068	—	—	—	5,919	—
Recovery of misappropriated funds	(3,412)	—	(1,592)	—	—	—
Acquisition costs	—	—	—	—	—	348
Total	346,116	17,677	58,322	88,264	90,906	83,598
Operating income (loss)	(258,463)	2,058	15,726	(3,138)	(35,911)	(11,298)
Other income (expense)						
Gain (loss) from derivative financial instruments	48,122	25,246	47,870	35,429	6,454	(599)
Gain (loss) from equity investment	—	—	—	(4,607)	(5,174)	6,768
Gain on forgiveness of debt	—	—	2,909	1,647	255	—
Other income (expense), net	108	(4)	(24)	207	111	12
Interest expense, net	(25,488)	(4,705)	(17,994)	(10,151)	(10,452)	(3,739)
Total	22,742	20,537	32,761	22,525	(8,806)	2,442
Income (loss) from continuing operations before income taxes	(235,721)	22,595	48,487	19,387	(44,717)	(8,856)
Income taxes	—	—	—	—	—	180
Income (loss) from continuing operations	(235,721)	22,595	48,487	19,387	(44,717)	(9,036)
Income (loss) from discontinued operations	(56,599)	(859)	(3,266)	643	(2,855)	—
Net income (loss)	(292,320)	21,736	45,221	20,030	(47,572)	(9,036)
Net (income) loss attributable to noncontrolling interest	147,398	(9,958)	—	—	—	—

Net income (loss) attributable to controlling interest	(144,922)	11,778	45,221	20,030	(47,572)	(9,036)
Preferred dividends	—	—	(1,980)	(7,779)	(9,083)	(11,047)
Accretion of redeemable preferred stock	—	—	(327)	(1,580)	(2,238)	(3,283)
Net income (loss) available to common stock	$ (144,922)	$ 11,778	$ 42,914	$ 10,671	$ (58,893)	$ (23,366)
Net income (loss) from continuing operations per share						
Basic	$ (2.77)	$ 0.39	$ 5.69	$ 1.14	$ (4.12)	$ (0.93)
Diluted	$ (2.77)	$ 0.39	$ 4.97	$ 0.67	$ (4.12)	$ (0.93)
Balance Sheet Data (at end of period)						
Total assets	$ 283,655	$ 310,234	$ 296,812	$ 306,711	$ 146,663	$ 183,082
Noncurrent liabilities excluding debt	$ 15,121	$ 17,148	$ 13,831	$ 20,903	$ 13,822	$ 79,493
Long-term debt	$ 19,295	$ 20,251	$ 209,721	$ 190,000	$ 57,500	$ 92,000
Redeemable preferred stock	$ —	$ —	$ 50,622	$ 56,736	$ 73,152	$ 23,828

Comparability of information in the above table between years is affected by, among other things, (1) changes in the annual average prices for oil and natural gas, (2) our investment in CEP during 2011, (3) investigation and litigation costs associated with the misappropriation in 2009, (4) the Recombination in 2010 and expenses related to the Recombination in 2009 and 2010, (5)

Table of Contents

impairment of production properties of $215.1 million in 2009 and $5.9 million in 2012, (6) the sale of some of our Appalachian Basin oil and gas properties in 2010 and 2011, (7) the sale of KPC in 2012 and (8) increased oil production in 2013 related to drilling and development activity.

ITEM 7.MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The accompanying consolidated financial statements, including the notes thereto, contain detailed information that should be read in conjunction with the following discussion.

Overview of Our Company

We are an independent oil and gas company engaged in the acquisition, exploration, development, production and gathering of crude oil and natural gas. Our primary production activity is focused in the Cherokee Basin, a 15-county region in southeastern Kansas and northeastern Oklahoma, and Central Oklahoma. We also have minor oil and gas producing properties in the Appalachian Basin. We previously owned an interstate natural gas pipeline which was sold in September 2012, and we report its results as a discontinued operation in our financial statements.

Strategy

Our strategy is to acquire, develop and efficiently manage long-lived oil and gas properties and undeveloped leases in proven producing regions where we recognize the opportunity to add value through additional development, application of modern technologies and techniques, and efficiencies gained through consolidation. Our plans are to exploit our existing asset base and build regionally from our core operations, primarily in the Cherokee Basin and Central Oklahoma at present.

We are currently focused on increasing the percentage of oil and liquids in our production and reserves. As of and for the year ended December 31, 2012, our reserves and our production on an energy equivalent basis, included 19% and 3.4% oil, respectively. As of and for the year ended December 31, 2013, those percentages had increased to 23% and 7.4%, respectively. Our plan is to direct the substantial majority of development capital in 2014 toward oil weighted projects to continue accumulating oil production and reserve growth.

Key Factors Affecting Our Results of Operations

•Realized natural gas prices were $3.55/Mcf during 2013 compared to $2.68/Mcf in 2012 and $3.98/Mcf in 2011.

•Low natural gas prices have resulted in reduced natural gas development, which has led to a decline in our natural gas production. Our natural gas production was 14.5 Bcf in 2013, 16.4 Bcf in 2012 and 18.3 Bcf in 2011.

•Realized oil prices were $94.56/Bbl during 2013 compared to $90.13/Bbl in 2012 and $90.60/Bbl in 2011.

•High oil prices have resulted in an increased focus on oil development, which has led to an increase in our oil production. Our oil production was 192,474 barrels in 2013, 95,863 barrels in 2012 and 78,087 barrels in 2011.

•We continued to focus on reducing our costs in both our field operations and our Oklahoma City office.

•Our employee headcount was 209, 216 and 301, at December 31, 2013, 2012 and 2011, respectively.

•Lease operating expenses and gathering expenses were $35.1 million during 2013 compared to $37.6 million in 2012 and $39.8 million in 2011.

•General and administrative expenses were $16.0 million during 2013 compared to $14.8 million in 2012 and $16.0 million in 2011.

•We closed three acquisitions in 2013 related to oil and gas properties in Central Oklahoma with a total purchase price of approximately $13.0 million.

Table of Contents

How We Evaluate Our Operations

Management uses and expects to continue to use a variety of financial and operational metrics to analyze performance and the health of the business. These metrics focus on rates of return and cost efficiency with an emphasis on cash costs. A few of the metrics we focus on include: (1) volume and mix of production and reserves; (2) reserve life; (3) lease operating expense, gathering expense and general and administrative expense; (4) gathering throughput volumes, fuel consumption by our facilities and natural gas sales volumes; and (5) debt balances.

General Trends and Outlook

Realized Prices

We sell our Cherokee Basin gas production based on the Southern Star index. We sell the majority of our natural gas in the Appalachian Basin based on the Dominion Southpoint index, with the remainder sold on a local basis. The Southern Star prices typically are at a discount to the NYMEX pricing at Henry Hub, the regional pricing point, whereas Appalachian prices typically are at a premium to NYMEX pricing. During 2013, the basis discount in the Cherokee Basin ranged from \$0.03 to \$0.33/MMBtu. According to the U.S. Energy Information Administration ("EIA"), the Henry Hub spot price averaged \$3.73 per MMBtu in 2013. NYMEX strip prices at March 3, 2014, average \$4.54/MMBtu, \$4.33/MMBtu, and \$4.26/MMBtu for the forward 12, 24 and 36 month period, respectively. We sell the majority of our oil production under a contract priced at a fixed discount to NYMEX WTI oil prices. Oil and natural gas prices historically have been very volatile and will likely continue to be so in the future.

We utilize our hedging program to attempt to mitigate the risk that variability of commodity pricing creates for our cash flows. See Part II, Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" of this Annual Report on Form 10-K for further details on our hedging activity.

Supply and Demand of Oil and Gas

North American crude oil and natural gas prices have historically been volatile based on supply and demand dynamics and we expect this volatility to continue into 2014. Although natural gas prices improved in 2013 compared to 2012, natural gas continues to be challenged due to an imbalance between supply and demand across North America. However, arctic air movements across North America during the early weeks of 2014 have caused natural gas demand to surge. As storage inventories have significantly declined in response to the recent weather conditions, natural gas prices have surpassed $5 per Mcf for the first time since the summer of 2010. Further helping demand, new uses of natural gas in industrial, power and other sectors will continue to help support price dynamics. Nevertheless, we still expect natural gas prices to be range-bound as natural gas supply continues to grow. Looking to 2014, we expect natural gas prices will remain relatively consistent or possibly increase moderately from 2013 levels.

Crude oil prices remained relatively stable throughout 2013, and oil continues to be more valuable than natural gas on a relative energy-equivalent basis. As a result, we and other producers have been focused on growing oil production. North American crude oil supply continues to increase due to the continued use of horizontal drilling technology throughout the United States. Global crude oil demand is expected to grow with supply in 2014. As crude oil supply grows, transportation capacity to downstream markets will be increasingly important. Bottlenecks and other transportation limitations may continue to add volatility among U.S. grades of oil. However, we expect 2014 oil prices will remain relatively consistent with 2013.

Drilling Programs

Our 2013 exploration and development capital expenditures totaled $40.0 million. Included in the $40.0 million, we successfully completed 152 new wells and recompleted 62 wells in the Cherokee Basin, completed three new wells and recompleted nine wells in Central Oklahoma, and recompleted a well in the Appalachian Basin. Our development activity in 2013 was directed toward increasing oil production and reserves in response to the low natural gas price environment. As a result of oil focused development, oil production in 2013 increased 101% over the prior year to 192,474 barrels while oil reserves increased from 2.7 MMBbl at year-end 2012 to 4.4 MMBbl at year-end 2013.

One of our most significant projects has been to reconfigure our entire compression system in the Cherokee Basin. This program was piloted with a proof of concept phase in 2012 and began to be fully implemented in 2013. We expect the project to be complete in the first half of 2014. The project is expected to cost approximately $8.2 million, with roughly $5.5 million of the project cost in 2014, and result in compression rental savings of approximately $3.2 million per year and to reduce fuel use of about 2.5 MMcf/d as compared to what it was prior to the project.

Table of Contents

Our focus for 2014 will continue to be on growing the percentage of oil included in our production and reserves through development, leasing, and opportunistic acquisitions. We have budgeted approximately $15.0 million for exploration and developmental drilling with the majority of our budget focused on horizontal oil wells in Central Oklahoma. If attractive opportunities arise, additional capital may be directed towards further oil development in Central Oklahoma. We intend to fund our 2014 capital expenditures with cash flow from operations and availability under our credit facility.

Results of Operations

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

The following table presents financial and operating data for the fiscal years ended December 31, 2012 and 2013.

	Year Ended December 31, 2012	2013	Increase/(Decrease)	
	($ in thousands, except per unit data)			
Natural gas sales	$ 43,911	$ 51,489	$ 7,578	17.3 %
Crude oil sales	$ 8,640	$ 18,200	$ 9,560	110.6 %
Gathering revenue	$ 2,444	$ 2,611	$ 167	6.8 %
Production expense	$ 42,213	$ 40,085	$ (2,128)	(5.0) %
Depreciation, depletion and amortization	$ 27,669	$ 27,369	$ (300)	(1.1) %
Impairment of oil and gas assets	$ 5,919	$ —	$ (5,919)	(100.0) %
Gain (loss) on disposal of assets	$ (295)	$ 194	$ 489	(165.8) %
Sales Data - Volumes				
Natural gas sales (MMcf)	16,389	14,521	(1,868)	(11.4) %
Oil sales (Bbls)	95,863	192,474	96,611	100.8 %
Total sales (MMcfe)	16,964	15,676	(1,288)	(7.6) %
Average daily sales (MMcfe/d)	46.3	42.9	(3.4)	(7.3) %
Average Sales Price per Unit				
Natural gas (Mcf)	$ 2.68	$ 3.55	$ 0.87	32.3 %
Oil (Bbl)	$ 90.13	$ 94.56	$ 4.43	4.9 %
Natural gas equivalent (Mcfe)	$ 3.10	$ 4.45	$ 1.35	43.5 %
Average Unit Costs per Mcfe				

Production expense	$ 2.49	$ 2.56	$ 0.07	2.8	%
Depreciation, depletion and amortization	$ 1.63	$ 1.75	$ 0.12	7.4	%

Natural gas sales increased $7.6 million, or 17.3%, from $43.9 million for the year ended December 31, 2012, to $51.5 million for the year ended December 31, 2013. Higher realized natural gas prices increased revenues by $12.6 million while lower volumes decreased revenues by $5.0 million. Natural gas volumes decreased 1.9 Bcf due to continued suspension of our gas development throughout 2013 as oil development remained more attractive economically. Crude oil revenues increased $9.6 million, or 110.6%, from $8.6 million for the year ended December 31, 2012 to $18.2 million for the year ended December 31, 2013. Increased oil volumes contributed $8.7 million of the increase in oil revenues. Average realized natural gas prices increased from $2.68 per Mcf in 2012 to $3.55 per Mcf in 2013 while average oil prices increased from $90.13 per barrel in 2012 to $94.56 per barrel in 2013. Oil and gas sales exclude realized gains or losses from our derivative financial instruments.

Gathering revenue increased $167,000, or 6.8%, from $2.4 million for the year ended December 31, 2012, to $2.6 million for the year ended December 31, 2013. The increase was due to higher gas prices during 2013.

Production expense consists of lease operating expenses, severance and ad valorem taxes and gathering expense. Production expense decreased $2.1 million, or 5.0%, from $42.2 million for the year ended December 31, 2012, to $40.1 million for the year ended December 31, 2013. Expense in 2012 included a $368,000 charge related to field reorganization. When this charge is excluded, production costs decreased $1.8 million, or 4.2%, from the prior year adjusted cost of $41.8 million. Lower compressor rental costs of $1.1 million, lower repairs and maintenance of $635,000, lower workover costs of $486,000, lower ad valorem taxes of $271,000, and reductions in other operational areas were partially offset by higher production taxes of $614,000 and higher electricity costs of $263,000. As a result of lower production volume, production expense per Mcfe increased from $2.49, or an adjusted $2.47, per Mcfe for the year ended December 31, 2012, to $2.56 per Mcfe for the year ended December 31, 2013.

Table of Contents

Depreciation, depletion and amortization remained relatively consistent from the prior year as it decreased $300,000 from $27.7 million for the year ended December 31, 2012, to $27.4 million for the year ended December 31, 2013. On a per unit basis, we had an increase of $0.12 per Mcfe from $1.63 per Mcfe for the year ended December 31, 2012, to $1.75 per Mcfe for the year ended December 31, 2013.

General and administrative expenses increased $1.2 million, or 8.0%, from $14.8 million for the year ended December 31, 2012, to $16.0 million for the year ended December 31, 2013. The 2012 period included a $503,000 charge related to reorganization of our Oklahoma City office and $2.2 million of non-cash compensation. Expense in 2013 included $1.6 million of legal fees related to the litigation with CEP and Sanchez Energy, a $454,000 workman’s compensation charge, and $4.3 million of non-cash compensation. Excluding these charges, general and administrative expenses totaled $9.7 million, or 20.1%, lower than the prior year. The decrease was due primarily to reduced wages, benefits and bonuses of $601,000, higher capitalized labor of $434,000, and lower contract labor and other services of $299,000.

Other income (expense) consists primarily of realized and unrealized gains or losses from derivative instruments, gain or loss from equity investment, and net interest expense. We recorded a realized gain of $73.2 million and loss of $2.3 million on our derivative contracts for the years ended December 31, 2012 and 2013, respectively. We recorded a $66.7 million unrealized loss and a $1.7 million unrealized gain on our derivative contracts for the years ended December 31, 2012 and 2013, respectively. During 2012, we exited our above-market natural gas swap contracts, originally scheduled to settle in 2013, for proceeds of $30.2 million. These proceeds are included in the 2012 realized gains disclosed above. We recorded a mark-to-market loss of $5.2 million and a mark-to-market gain of $6.8 million on our equity investment in CEP for the years ended December 31, 2012 and 2013, respectively. The gain in 2013 was the result of an increase in the market price of CEP’s publicly traded equity, which consequently increased the value of our investment. Interest expense, net, was $10.5 million and $3.7 million for the years ended December 31, 2012 and 2013, respectively. Interest expense was lower as a result of reduced debt. We recorded a gain on forgiveness of debt of $255,000 for the year ended December 31, 2012 as a result of the restructuring of the QER Loan, discussed in Note 10 in Part II, Item 8. “Financial Statements and Supplementary Data.” There was no gain on forgiveness of debt for the year ended December 31, 2013.

We recorded a loss from discontinued operations of $2.9 million for the year ended December 31, 2012. The loss was related to the operations and subsequent sale of our interstate natural gas pipeline. There were no discontinued operations for the year ended December 31, 2013.

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

The following table presents financial and operating data for the fiscal years ended December 31, 2011 and 2012.

	Year Ended December 31,			
	2011	2012	Increase/(Decrease)	
	($ in thousands, except per unit data)			
Natural gas sales	$ 72,812	$ 43,911	$ (28,901)	(39.7)%
Crude oil sales	$ 7,075	$ 8,640	$ 1,565	22.1 %
Gathering revenue	$ 5,239	$ 2,444	$ (2,795)	(53.3)%
Production expense	$ 47,136	$ 42,213	$ (4,923)	(10.4)%
Depreciation, depletion and amortization	$ 24,088	$ 27,669	$ 3,581	14.9 %
Impairment of oil and gas assets	$ —	$ 5,919	$ 5,919	* %
Gain (loss) on disposal of assets	$ 10,557	$ (295)	$ (10,852)	* %
Sales Data - Volumes				
Natural gas sales (MMcf)	18,309	16,389	(1,920)	(10.5)%
Oil sales (Bbls)	78,087	95,863	17,776	22.8 %
Total sales (MMcfe)	18,778	16,964	(1,814)	(9.7) %
Average daily sales (MMcfe/d)	51.4	46.3	(5.1)	(9.9) %
Average Sales Price per Unit				
Natural gas (Mcf)	$ 3.98	$ 2.68	$ (1.30)	(32.7)%
Oil (Bbl)	$ 90.60	$ 90.13	$ (0.47)	(0.5) %
Natural gas equivalent (Mcfe)	$ 4.25	$ 3.10	$ (1.15)	(27.1)%
Average Unit Costs per Mcfe				
Production expense	$ 2.51	$ 2.49	$ (0.02)	(0.8) %
Depreciation, depletion and amortization	$ 1.28	$ 1.63	$ 0.35	27.3 %

* Not meaningful.

Natural gas sales decreased $28.9 million, or 39.7%, from $72.8 million for the year ended December 31, 2011, to $43.9 million for the year ended December 31, 2012. Lower realized natural gas prices decreased revenues by $21.3 million while lower volumes decreased revenues by $7.6 million. Natural gas volumes decreased 1.9 Bcf due to suspended gas development during the low gas price environment in 2012 and natural production declines. These decreases were partially offset by higher crude oil revenues of $1.6 million, which increased from $7.1 million during 2011 to $8.6 million during 2012, with most of the increase a result of higher volumes. Average realized natural gas prices decreased from $3.98 per Mcf in 2011 to $2.68 per Mcfe in 2012 while average oil price decreased from $90.60 per barrel in 2011 to $90.13 per barrel in 2012. Oil and gas sales exclude hedge settlements.

Gathering revenue decreased $2.8 million, or 53.3%, from $5.2 million during the year ended December 31, 2011, to $2.4 million during the year ended December 31, 2012. The decrease is primarily due to the settlement of the royalty lawsuits discussed below, which lowered the rates we receive for gathering royalty interest gas coupled with lower production volumes and lower realized prices.

Production expense decreased $4.9 million, or 10.4%, from $47.1 million during the year ended December 31, 2011, to $42.2 million during the year ended December 31, 2012. Expense in 2012 included a $368,000 charge related to our field reorganization in March 2012. Excluding this charge, production expense was $5.3 million lower than the prior year. The decrease was driven by lower labor costs of $2.0 million, lower repairs and maintenance of $1.0 million and lower vehicle and equipment costs of $1.7 million. These decreases are attributed to field efficiency projects that we began in the latter half of 2011 and continued in 2012. In addition, we incurred lower production taxes of $2.7 million partially driven by the decline in pricing and production. These cost reductions were partially offset by a reduction in capitalized costs of $2.1 million. Excluding the field reorganization charge, production expense per Mcfe decreased $0.04, or 1.6%, from $2.51 per Mcfe during the year ended December 31, 2011, to $2.47 per Mcfe during the year ended December 31, 2012.

Depreciation, depletion and amortization increased $3.6 million, or 14.9%, from $24.1 million during the year ended December 31, 2011, to $27.7 million during the year ended December 31, 2012. The increase was a result of a higher depreciation rate partially offset by a decline in production volumes. On a per unit basis, we had an increase of $0.35 per Mcfe from $1.28 per Mcfe during the year ended December 31, 2011, to $1.63 per Mcfe during the year ended December 31, 2012.

Impairment of our oil and gas properties was $5.9 million for the year ended December 31, 2012. We are required to assess the recoverability of the carrying value of our oil and gas properties against the present value of their future expected net revenues utilizing a twelve month average first of the month price for oil and natural gas. As a result of a decrease in the average natural gas price in 2012 relative to the prior year, the carrying value of our oil and natural gas properties exceeded the present value, thus requiring us to record an impairment during 2012.

We recorded a gain from the disposal of oil and gas assets of $10.6 million during the year ended December 31, 2011, compared to a loss of $295,000 during the year ended December 31, 2012. The gain in 2011 was primarily related to the second and third phases of the Appalachian Basin asset sale partially offset by $1.9 million of losses on the disposal of excess equipment.

General and administrative expenses decreased $1.2 million, or 7.4%, from $16.0 million during the year ended December 31, 2011, to $14.8 million during the year ended December 31, 2012. During the 2011 period, a $757,000 charge was recorded for the closure of our Houston office. During the 2012 period, a $503,000 severance charge was recorded for the restructuring of our Oklahoma City office. Excluding these charges, general and administrative expenses were $0.9 million, or 6.2%, lower than the prior year. The decrease was primarily due to reduced wages and benefits of $1.2 million and lower legal, accounting and audit fees of approximately $1.1 million. The reductions were partially offset by higher non-cash compensation expense of $837,000 and cash bonus compensation of $751,000. Non-cash compensation was higher as a result of the forfeiture of unvested grants in the prior-year period coupled with new award grants in the current year. Bonus compensation was higher as a result of growth in oil production and reserves, benchmarked against various other year-end performance metrics.

Litigation reserve was $11.6 million for the year ended December 31, 2011. The expense during 2011 was due to settlement costs for our royalty owner lawsuits in Oklahoma and Kansas. The royalty owner lawsuits included allegations that we failed to properly make payments to certain royalty owners in the past. Our Oklahoma royalty owner lawsuits were settled and funded in July 2011 for $5.6 million. Our Kansas royalty owner lawsuits were settled in December 2011 for $7.5 million with payments of $3.0 million and $4.5 million made in January 2012 and December 2012, respectively. As part of these settlements, all ambiguity in the calculation of prospective, as well as prior, royalties in our lease agreements was eliminated. Subsequent to the settlements, we have charged post-production costs to royalty and overriding royalty interest owners pursuant to an agreed upon formula. These settlements comprised the last material litigation or dispute related to our predecessor entities or management. The expense recorded in 2011 for these lawsuits established the $5.6 million reserve for the Oklahoma matters and increased the reserve for the Kansas lawsuit by $6.0 million.

Table of Contents

Other income (expense) consists primarily of gains (losses) from derivative instruments, gain (loss) from equity investment, gain from forgiveness of debt and net interest expense. We recorded realized gains of $33.7 million and $73.2 million on our derivative contracts for the years ended December 31, 2011 and 2012, respectively. We recorded a $1.7 million unrealized gain and a $66.7 million unrealized loss on our derivative contracts for the years ended December 31, 2011 and 2012, respectively. During 2012, we exited our above market natural gas swap contracts originally scheduled to settle in 2013 for proceeds of $30.2 million. These proceeds are included in the realized gains disclosed above. The mark-to-market losses on our equity investment in CEP were $4.6 million and $5.2 million for the years ended December 31, 2011 and 2012, respectively. These losses are the result of a decline in the market price of CEP's publicly traded equity, which consequently reduced the value of our investment. Interest expense, net, was $10.2 million and $10.5 million for the years ended December 31, 2011 and 2012, respectively. Although our debt was lower in 2012, interest expense was higher due to the $1.2 million write-off of unamortized debt fees associated with our previous credit facility upon the refinancing of that facility in December 2012. We recorded gains on forgiveness of debt of $1.6 million and $255,000 for the years ended December 31, 2011 and 2012, respectively. Both gains are the result of the restructuring of the QER Loan, discussed in Note 10 in Part II, Item 8. "Financial Statements and Supplementary Data."

We recorded income from discontinued operations of $643,000 for the year ended December 31, 2011, compared to a loss of $2.9 million for the year ended December 31, 2012. The reduction was driven by the $5.4 million loss on the sale of KPC in September 2012 partially offset by a $1.9 million improvement in the operating results of the pipeline compared to the prior year. Prior to the sale of KPC, revenues were higher in 2012 as a result of increased throughput from growing gas volumes associated with oil production in Osage County, Oklahoma, while expenses were lower as the prior year included costs for a capacity lease that expired in October 2011, an external gas leak that occurred during the first quarter of 2011 and contract services that we did not require in the current year. These improvements more than offset the foregone net revenues from KPC subsequent to its sale in September 2012.

Liquidity and Capital Resources

Debt Borrowings

Our total debt increased from $57.5 million at December 31, 2012 to $92.0 million at December 31, 2013. The additional debt was used for capital expenditures, including acquisitions. We refinanced our existing credit facility in December 2012, resulting in a new, four-year $200 million senior secured revolving facility.

Historical Cash Flows and Liquidity

Cash flows from operating activities have historically been driven by the quantities of our production and the prices received from the sale of this production. Prices of oil and gas have historically been very volatile and can significantly impact the cash from the sale of our production. Use of derivative financial instruments help mitigate this price volatility. Proceeds from or payments for derivative settlements are included in cash flows from operations. Cash expenses also impact our operating cash flow and consist primarily of production operating costs, production taxes, interest on our indebtedness and general and administrative expenses.

Cash flows from operations totaled $42.7 million, $69.1 million and $11.2 million for the years ended December 31, 2011, 2012 and 2013, respectively. The decrease from 2012 to 2013 is mainly due to the significant reduction in realized cash from derivative contracts in 2013 compared to 2012. The increase from 2011 to 2012 is due to higher realized gains on derivative contracts and lower operating expenses compared to 2011, partially offset by lower revenues in 2012.

Cash flows from investing activities have historically been driven by exploration and development costs, leasehold acquisitions, acquisitions of businesses and sales of oil and gas properties. Net cash used in investing activities was $27.8 million and $49.7 million for the years ended December 31, 2011 and 2013, respectively, compared to net cash received of $35.6 million for the year ended December 31, 2012. Cash used in investing activities in 2013 was largely a result of $52.3 million of capital expenditures. Cash from investing activities in 2012 was the result of $53.4 million in gross proceeds from the KPC sale partially offset by $16.8 million of capital expenditures and $1.5 million set aside as restricted cash prior to our transitioning outstanding letters of credit to our new credit facility. Cash used in investing activities in 2011 was a result of $29.3 million of capital expenditures and $12.9 million of cash for our investment in CEP partially offset by proceeds of $14.4 million (including proceeds of $1.6 million from the sale of stock received as consideration) from asset sales primarily related to the Appalachian Basin sale.

Table of Contents

The following table sets forth our capital expenditures, including costs we have incurred but not paid for the periods presented:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Capital Expenditures			
Leasehold acquisition	$ 853	$ 203	$ 16,590
Exploration	—	—	—
Development	23,825	12,506	40,004
Pipeline	839	563	—
Other items	4,736	4,238	4,093
Total capital expenditures	$ 30,253	$ 17,510	$ 60,687

Cash flows from financing activities have historically been driven by borrowing and repayments on debt instruments, issuances of equity and the costs associated with these activities. Cash used in financing activities was $15.3 million and $104.6 million for the years ended December 31, 2011 and 2012, respectively, while cash from financing activities was $37.9 million for the year ended December 31, 2013. The cash from financing activities in 2013 was from borrowings from our Borrowing Base Facility and from issuance of $4.1 million of our common stock under our at-the-market sales agreement. The cash used in 2012 was primarily debt repayments of $193.0 million to settle our prior credit facilities along with debt and equity issuance costs of $2.3 million. These outflows were partially offset by $57.5 million in proceeds from our Borrowing Base Facility, $32.5 million in proceeds from the issuance of common stock, preferred stock and warrants to White Deer, and $724,000 in proceeds from the issuance of common stock under our at-the-market program described below. The cash used in 2011 was primarily due to $15.3 million in net repayments of debt.

KPC Sale

On September 28, 2012, we sold our interstate pipeline subsidiary KPC to MV for $53.5 million in cash, $53.4 million net of a working capital adjustment. Of this amount, $500,000 was deposited into an escrow account pending the acceptable cleanup of a site previously owned by KPC. The cleanup was completed and the escrowed funds were released in January 2013. MV also agreed to make additional payments of $1.0 million for each of the next four years if qualified EBITDA, as defined in the purchase agreement, of KPC for that year exceeds a target amount.

White Deer Investment

At December 31, 2013, White Deer holds $102.8 million in liquidation preference of our Series A Cumulative Redeemable Preferred Stock (the “Series A Preferred Stock”) along with warrants to purchase 20,161,351 shares of our common stock at a weighted average exercise price of $1.54 per share. In addition, White Deer also holds 113,521 shares of our Series B Voting Preferred Stock (the “Series B Preferred Stock”), each share entitled to 100 votes, and 10,958,601 shares of our common stock. Our issuance of equity to White Deer occurred in five transactions as disclosed below.

•On September 21, 2010, we issued to White Deer $60 million initial liquidation preference of our Series A Preferred Stock along with 7 1/2 year warrants to purchase 19,047,619 shares of our common stock at an exercise price of $3.15 per share.

•On February 9, 2012, we issued to White Deer 2,180,233 shares of our common stock at $3.44 per share for an aggregate purchase price of $7.5 million.

•On August 1, 2012, we issued to White Deer 3,076,923 shares of our common stock at $1.95 per share, $6.0 million initial liquidation preference of our Series A Preferred Stock and warrants to purchase 3,076,923 shares of common stock at an exercise price of $1.95 per share. Total proceeds from the issuance were $12.0 million.

•On December 20, 2012, we issued to White Deer 4,577,464 shares of our common stock at $1.42 per share, $6.5 million initial liquidation preference of our Series A Preferred Stock and warrants to purchase 4,577,464 shares of common stock at an exercise price of $1.42 per share. Total proceeds from the issuance were $13.0 million.

•On December 13, 2013, we issued to White Deer 1,123,981 shares of our common stock with a fair value of $1.5 million in exchange for the retirement of warrants exercisable for 22,241,333 shares of our common stock together with a like number of one one-hundredths of a share of Series B Voting preferred Stock that were issued as a unit with the warrants. For additional details, see Note 12 in Part II, Item 8. “Financial Statements and Supplementary Data.”

Table of Contents

The Series A Preferred Stock is entitled to a cumulative dividend of 12% per year on its liquidation preference, compounded quarterly. Prior to December 31, 2014, we can elect to pay dividends on the Series A Preferred Stock in cash. During this period, if such dividends are not paid in cash, the liquidation preference of the Series A Preferred Stock will increase by the amount of the dividend and we will issue additional warrants exercisable for a number of shares of our common stock equal to the amount of the dividend divided by, with respect to the Series A Preferred Stock issued in September 2010, the closing price of the common stock on the trading day prior to the dividend payment date or, with respect to the Series A Preferred Stock issued in August and December 2012, $1.95 and $1.42, respectively, with the exercise price of such warrants equal to such applicable price.

We have not paid cash dividends since White Deer's initial investment in September 2010 but instead have chosen to increase the liquidation preference on the Series A Preferred Stock by $30.3 million, the cumulative amount of accrued dividends through December 31, 2013. Excluding the warrants retired in the Warrant Exchange, as a result of paying dividends in kind since the initial investment, we have also issued warrants to purchase 12,506,964 shares of our common stock at a weighted average exercise price of $1.48 per share. We are required to redeem the Series A Preferred Stock on March 21, 2018, at 100% of the liquidation preference. See Note 12 in Part II, Item 8 of this Annual Report for further details on the securities issued as a result of White Deer's investment.

Credit Agreement

On December 20, 2012, we completed a refinancing of our existing revolving credit facility with a new group of banks. The refinancing was structured as an amendment to the existing facility to minimize costs. At refinancing, the existing facility was amended and restated by the Third Amended and Restated Credit Agreement (the "Borrowing Base Facility"). The Borrowing Base Facility, which is currently our sole credit facility, is a $200 million senior secured revolving facility secured by a first lien on substantially all of our assets except the assets of Constellation Energy Partners Management, LLC, one of our consolidated subsidiaries. See Note 10 in Part II, Item 8. in this Annual Report on Form 10-K for a summary of the material terms of this facility.

At December 31, 2013, the borrowing base under the Borrowing Base Facility was $115.0 million with outstanding borrowings of $92.0 million and $1.3 million in outstanding letters of credit. We had $21.7 million available under the Borrowing Base Facility at that date.

Sources of Liquidity in 2013 and Capital Requirements

We rely on our cash flows from operating activities as a source of internally generated liquidity. During two of the past three years, our cash flows from operating activities have been sufficient to fund our investing activities. In 2013 we borrowed $34.5 million to fund capital expenditures. Our long-term ability to generate liquidity internally depends in part on our ability to hedge future production at attractive prices as well as our ability to control operating expenses. We generated cash of $33.7 million and $73.6 million from settlements of our oil and gas derivatives during 2011 and 2012, respectively, while we owed cash of $2.3 million in 2013. The cash we generated in 2012 includes $30.2 million from the early exit of above market natural gas swap contracts originally scheduled to settle in 2013. These contracts were settled early in connection with our debt refinancing in 2012. Our natural gas contracts that settled during 2010 to 2012 were entered into prior to 2010 and were priced in the range of $6.26 to $7.28 per MMBtu. We have natural gas and crude oil swap contracts covering a portion of our production between 2014 to 2016. At March 3, 2014, our outstanding natural gas swaps have a weighted average price of $4.01 per MMBtu while our open crude oil swaps have a weighted average price between $93.07 per barrel. Our outstanding contracts are disclosed below under Commodity Price Risk.

From time to time, we may issue equity to fund certain transactions, such as our CEP investment, to repay outstanding debt and for working capital purposes. As discussed above, we issued additional equity to White Deer on three separate occasions in 2012 for gross proceeds of $32.5 million.

We have an effective $100 million universal shelf registration statement on Form S-3. We are initially limited to selling debt or equity securities under the shelf registration statement in one or more offerings over a 12 consecutive month period for a total initial public offering price not exceeding one third of our public equity float. The registration statement is intended to give us the flexibility to sell securities if and when market conditions and circumstances warrant, to provide funding for growth or other strategic initiatives, for debt reduction or refinancing and for other general corporate purposes. The actual amount and type of securities or combination of securities and the terms of those securities will be determined at the time of sale, if such sale occurs. If and when a particular series of securities is offered, the prospectus supplement relating to that offering will set forth our intended use of the net proceeds. In addition, we have entered into an at-the-market issuance sales agreement with a sales agent relating to the offering from time to time of shares of our common stock under the shelf registration statement. Sales of shares of our common stock, if any, may be made directly on the NASDAQ Global Market, on any other existing trading market for the common stock or through a market maker, or in privately negotiated transactions, subject to our approval. Our sales agreement is limited to the sale of up to a number of shares of common stock with an initial offering price not to exceed the amount that can be sold under the registration statement. As of the date of the

Table of Contents

sales agreement, such amount is limited to approximately $20.3 million. During the first half of 2013, we sold 2,592,313 shares of common stock under the program for $4.0 million, net of $115,000 in agent commissions. We renewed our at-the-market program in late August 2013. There were no sales of common stock in the third and fourth quarters.

We rely on our Borrowing Base Facility as an external source of long and short-term liquidity. At March 3, 2014, we had $95 million of outstanding borrowings and $20 million of availability under this facility. The borrowing base under our Borrowing Base Facility will be redetermined on May 1, 2014, based on reserves at December 31, 2013. The borrowing base under that facility is determined based on the value of our oil and natural gas reserves at our lenders' forward price forecasts, which are generally derived from futures prices. With the current availability under our Borrowing Base Facility and expected cash flows from operations, we believe that we have sufficient liquidity to fund our capital expenditures and financial obligations through 2014.

Contractual Obligations

We have certain contractual commitments in the ordinary course of business, including debt service requirements, purchase obligations and operating lease commitments. The following table summarizes these commitments at December 31, 2013:

	Payments Due by Period				
	Total	Less Than 1 Year	1 - 3 Years	4 - 5 Years	More Than 5 Years
	(in thousands)				
Borrowing Base Facility	$ 92,000	$ —	$ 92,000	$ —	$ —
Interest on bank credit facility (1)	8,652	2,913	5,739	—	—
Purchase obligations	2,374	1,314	1,059	1	—
Operating lease obligations	7,256	3,558	3,315	383	—
Total commitments	$ 110,282	$ 7,785	$ 102,113	$ 384	$ —

(1) Interest due by period is an estimate as the credit facility has variable interest rate.

Off-Balance Sheet Arrangements

At December 31, 2013, we did not have any relationships with unconsolidated entities or financial partnerships, such as entities often referred to as structured finance or special purpose entities, which would have been established for the purpose of facilitating off-balance sheet arrangements or other contractually narrow or limited purposes. In addition, we do not engage in trading activities involving non-exchange traded contracts. As such, we are not exposed to any financing, liquidity, market, or credit risk that could arise if we had engaged in such activities.

Critical Accounting Policies

The preparation of our consolidated financial statements requires us to make assumptions and estimates that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the dates of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting periods. We base our estimates on historical experiences and various other assumptions that we believe are reasonable; however, actual results may differ. We believe the following critical accounting policies affect our more significant judgments and estimates used in the preparation of our consolidated financial statements.

Oil and Gas Reserves

Our most significant financial estimates are based on estimates of proved oil and gas reserves. Proved reserves represent estimated quantities of oil and gas that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future revenues, rates of production, and timing of development expenditures, including many factors beyond our control. The estimation process relies on assumptions and interpretations of available geologic, geophysical, engineering, and production data and, the accuracy of reserve estimates is a function of the quality and quantity of available data, engineering and geologic interpretation, and judgment. In addition, as a result of changing market conditions, commodity prices and future development costs will change from year to year, causing estimates of proved reserves to also change. Estimates of proved reserves are key components of our most significant financial estimates involving our unevaluated properties, our rate for recording depreciation, depletion and amortization and our full cost ceiling limitation. Our reserves are estimated on an annual basis by independent petroleum engineers.

Table of Contents

Oil and Natural Gas Properties

The method of accounting for oil and gas properties determines what costs are capitalized and how these costs are ultimately matched with revenues and expenses. We use the full cost method of accounting for oil and natural gas properties. Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of our oil and gas properties are capitalized.

Oil and gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved oil and gas reserves. Estimation of proved oil and gas reserves relies on professional judgment and the use of factors that cannot be precisely determined. Holding all other factors constant, if proved oil and gas reserves were revised upward or downward, earnings would increase or decrease, respectively. Subsequent proved reserve estimates that are materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of oil and gas properties unless the sale or disposition would have a significant impact on the depreciation, depletion, and amortization rate.

Under the full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum, plus the lower of cost or fair value of unevaluated properties less income tax effects (the “ceiling limitation”). Future net revenues used to calculate the ceiling do not include cash outflows associated with settling asset retirement obligations. We perform a quarterly ceiling test to evaluate whether the net book value of our full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion, and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of our full cost pool is a non-cash charge that reduces earnings and impacts stockholders’ equity in the period of occurrence and typically results in lower depreciation, depletion, and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The risk that we will be required to write-down the carrying value of our oil and natural gas properties increases during a period when oil or gas prices are depressed. In addition, a write-down may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly.

Unevaluated Properties

The costs directly associated with unevaluated properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination together with interest costs capitalized for these projects. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in our unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. Any impairment to unevaluated properties is transferred to the amortization base.

Future Abandonment Costs

We have significant legal obligations to plug, abandon and dismantle existing wells and facilities that we have acquired, constructed, or developed. Liabilities for asset retirement obligations are recorded at fair value in the period incurred. Upon initial recognition of the asset retirement liability, the asset retirement cost is capitalized by increasing the carrying amount of the long-lived asset by the same amount as the liability. Asset retirement costs included in the carrying amount of the related asset are subsequently allocated to expense as part of our depletion calculation. Additionally, increases in the discounted asset retirement liability resulting from the passage of time are recorded as depreciation expense.

Estimating the future asset retirement liability requires us to make estimates and judgments regarding timing, existence of a liability, as well as what constitutes adequate restoration. We use the present value of estimated cash flows related to our asset retirement obligations to determine the fair value. Present value calculations inherently incorporate numerous assumptions and judgments. These include the ultimate retirement and restoration costs, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the present value of the existing asset retirement liability, a corresponding adjustment will be made to the carrying cost of the related asset. There were no significant revisions for the years ended December 31, 2012 and 2013.

We have not recorded any asset retirement obligations relating to our gathering systems at December 31, 2012 and 2013 because we do not have any legal or constructive obligations relative to asset retirements of the gathering systems (see discussion in Note 9—Asset Retirement Obligations to the consolidated financial statements included in this Annual Report on Form 10-K).

Table of Contents

Derivative Instruments

Due to the historical volatility of oil and gas prices, we have implemented a hedging strategy aimed at reducing the variability of prices we receive for our production. Currently, we may use collars, fixed-price swaps and fixed price sales contracts as our mechanism for hedging commodity prices. Our current derivative instruments are not accounted for as hedges for accounting purposes in accordance with FASB ASC 815 Derivatives and Hedging. As a result, we account for our derivative instruments on a mark-to-market basis, and changes in the fair value of derivative instruments are recognized as gains and losses which are included in other income and expense in the period of change. While we believe that the stabilization of prices and production afforded us by providing a revenue floor for our production is beneficial, this strategy may result in lower revenues than we would have if we were not a party to derivative instruments in times of rising natural gas prices. For the year ended December 31, 2013, we recognized a total loss on derivative financial instruments in the amount of $599,000, consisting of a $2.3 million realized loss and a $1.7 million unrealized gain. We currently estimate the fair value of our commodity swaps with a discounted cash flow model utilizing, when possible, published forward commodity price curves and credit adjusted discount rates.

Income Taxes

We record our income taxes using an asset and liability approach in accordance with the provisions of FASB ASC 740 Income Taxes. We recognize deferred tax assets and liabilities for the expected future tax consequences of temporary differences (primarily property and equipment and the net operating loss carry forward) between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under FASB ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2012 and 2013, a full valuation allowance was recorded against our deferred tax assets.

We have net operating loss ("NOL") carryforwards that are available to reduce our U.S. taxable future income. Our ability to utilize NOL carryforwards to reduce our future federal taxable income and federal income tax is subject to various limitations under Internal Revenue Code ("IRC") Section 382. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of our stock during any three year period resulting in an aggregate change of more than 50% in the beneficial ownership of our Company. We experienced ownership changes within the meaning of IRC Section 382 on November 14, 2005, March 5, 2010, and September 21, 2010 and are therefore subject to IRC Section 382 limitations on our NOL carryforwards. See Note 11 in Part II, Item 8. of this Annual Report on Form 10-K for further discussion of these limitations.

FASB ASC 740 provides guidance on the measurement of the income tax benefit associated with uncertain tax positions, derecognition, classification, interest and penalties and financial statement disclosure. We regularly analyze tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FASB ASC 740. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. We accrue interest and penalties related to uncertain tax positions as income tax expense.

Recent Accounting Pronouncements

Recent accounting pronouncements relevant to us are discussed within Note 2 in Part II, Item 8. of this Annual Report on Form 10-K. There have been no recent accounting pronouncements that have had a material impact on our consolidated financial statements. Furthermore, we are not aware of any new accounting standards we will be required to adopt in the future that will have a material impact on our consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

The discussion in this section provides information about the financial instruments we use to manage commodity price and interest rate volatility. All contracts are financial contracts, which are settled in cash and do not require the actual delivery of a commodity quantity to satisfy settlement.

Commodity Price Risk

Our most significant market risk relates to the prices we receive for our oil and natural gas production. For example, NYMEX-WTI oil prices during 2013 ranged from a high of $110.53 per barrel to a low of $86.68 per barrel. Meanwhile, NYMEX natural gas futures prices during 2013 ranged from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu. In light of the historical volatility of

Table of Contents

these commodities, we periodically have entered into, and expect in the future to enter into, derivative arrangements aimed at reducing the variability of the prices we receive for our production.

We have used, and may continue to use, a variety of commodity-based derivative financial instruments, including collars, fixed-price swaps and basis protection swaps. Our fixed price swap transactions are settled based upon NYMEX pricing. Natural gas prices at our primary delivery point in the Cherokee Basin are based on the Southern Star index, which is typically at a discount to the NYMEX pricing at Henry Hub. Settlement for our gas derivative contracts typically occurs in advance of our purchaser receipts.

While we believe that the oil and gas price derivative arrangements we enter into are important to our program to manage price variability for our production, we have not designated any of our derivative contracts as hedges for accounting purposes. We record all derivative contracts on the balance sheet at fair value, which reflects changes in prices. Both realized and unrealized gains and losses from settlements of or changes in fair values of our derivative contracts are currently recognized in other income (expense) as they occur. As a result, our current period earnings may be significantly affected by changes in fair value of our commodity derivative contracts. Changes in fair value are principally measured based on period-end forward prices compared to the contract price.

Gains and losses associated with derivative financial instruments related to gas and oil production were as follows for the years indicated.

	2011	2012	2013
	(in thousands)		
Realized gain (loss)	$ 33,692	$ 73,162	$ (2,271)
Unrealized gain (loss)	1,737	(66,708)	1,672
Total gain (loss) from derivative financial instruments	$ 35,429	$ 6,454	$ (599)

The following table summarizes the estimated volumes, fixed prices and fair value attributable to all oil and natural gas derivative contracts at December 31, 2013.

Year Ending December 31,			
2014	2015	2016	Total

	($ in thousands, except per unit data)			
Natural Gas Swaps				
Contract volumes (MMBtu)	10,327,572	8,983,560	7,814,028	27,125,160
Weighted-average fixed price per MMBtu	$ 4.01	$ 4.01	$ 4.01	$ 4.01
Fair value, net	$ (1,800)	$ (1,076)	$ (720)	$ (3,596)
Crude Oil Swaps				
Contract volumes (Bbl)	116,076	71,568	65,568	253,212
Weighted-average fixed price per Bbl	$ 95.19	$ 92.73	$ 90.33	$ 93.24
Fair value, net	$ (53)	$ 281	$ 340	$ 568
Total fair value, net	$ (1,853)	$ (795)	$ (380)	$ (3,028)

Interest Rate Risk

Although none are currently outstanding, from time to time we may enter into interest rate derivatives to mitigate our exposure to fluctuations in interest rates on variable-rate debt. At December 31, 2013, we had outstanding $92.0 million of variable-rate debt. A 1% increase in our interest rates would increase gross interest expense approximately $920,000 per year.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

Please see the accompanying consolidated financial statements and related notes thereto beginning on page F-1.

ITEM 9.CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) are designed to ensure that information required to be disclosed in reports filed or submitted under the Exchange Act is recorded, processed, summarized, and reported within the time periods specified in SEC rules and forms and that such information is accumulated and communicated to management, including the principal executive officer and the principal financial officer, to allow timely decisions regarding required disclosures. There are inherent limitations to the effectiveness of any system of disclosure controls and procedures, including the possibility of human error and the circumvention or overriding of the controls and procedures. Accordingly, even effective disclosure controls and procedures can only provide reasonable assurance of achieving their control objectives.

In connection with the preparation of this Annual Report on Form 10-K, our management, under the supervision and with the participation of our principal executive officer (who also currently serves as our principal financial officer), conducted an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures as of December 31, 2013. Based on that evaluation, such officer concluded that, as of December 31, 2013, our disclosure controls and procedures were effective with respect to the recording, processing, summarizing and reporting, within the time periods specified in the SEC's rules and forms, of information required to be disclosed by us in the reports that we file or submit under the Exchange Act.

Management's Annual Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP and includes those policies and procedures that (a) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of assets, (b) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, (c) provide reasonable assurance that receipts and expenditures are being made only in accordance with appropriate authorization of management and the board of directors, and (d) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of assets that could have a material effect on the financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In connection with the preparation of this Annual Report on Form 10-K, our management, under the supervision and with the participation of our principal executive officer (who also currently serves as our principal financial officer), conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring

Organizations of the Treadway Commission (the “1992 COSO Framework”). Based on the evaluation performed, we concluded that our internal control over financial reporting as of December 31, 2013, was effective based on the criteria set forth in the 1992 COSO Framework.

Changes in Internal Control Over Financial Reporting

There was no change in our internal control over financial reporting that occurred during the fourth quarter of 2013 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Auditor Attestation Report

This Annual Report does not include an attestation report of our independent registered public accounting firm regarding internal control over financial reporting due to an exemption provided by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”) enacted into law in July 2010. The Dodd-Frank Act provides smaller public companies and debt-only issuers with a permanent exemption from the requirement to obtain an external audit on the effectiveness of internal financial reporting controls provided in Section 404(b) of the Sarbanes-Oxley Act. PostRock is a smaller reporting company and is eligible for this exemption under the Dodd-Frank Act.

ITEM 9B. OTHER INFORMATION

None.

Table of Contents

PART III

ITEM 10.DIRECTORS, EXECUTIVE OFFICERS OF THE REGISTRANT AND CORPORATE GOVERNANCE

Information required by Part III, Item 10. is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

ITEM 11.EXECUTIVE COMPENSATION

Information required by Part III, Item 11. is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

ITEM 12.SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information required by Part III, Item 12. is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

ITEM 13.CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information required by Part III, Item 13. is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

ITEM 14.PRINCIPAL ACCOUNTING FEES AND SERVICES

Information required by Part III, Item 14. is incorporated by reference to our definitive proxy statement which is to be filed with the Securities Exchange Commission no later than 120 days after the end of our fiscal year pursuant to the Securities Exchange Act of 1934, as amended.

PART IV

ITEM 15.EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a)(1) and (2) Financial Statements See "Index to Financial Statements" set forth on page F-1 of this Annual Report on Form 10-K.

(a)(3) Index to Exhibits Exhibits requiring attachment pursuant to Item 601 of Regulation S-K are listed in the Index to Exhibits to this Annual Report on Form 10-K that is incorporated herein by reference.

Table of Contents

Index to Financial Statements

PostRock Energy Corporation

Table of Contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and
Stockholders of PostRock Energy Corporation:

We have audited the accompanying consolidated balance sheets of PostRock Energy Corporation and subsidiaries ("the Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, stockholders' equity (deficit), and cash flows for each of the years in the three-year period ended December 31, 2013. The Company's management is responsible for these consolidated financial statements. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2013 and 2012, and the consolidated results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

/s/ UHY LLP

Houston, Texas

March 27, 2014

Table of Contents

POSTROCK ENERGY CORPORATION

CONSOLIDATED BALANCE SHEETS

	December 31, 2012	December 31, 2013
	(in thousands, except share and per share data)	
ASSETS		
Current assets		
Cash and equivalents	$ 525	$ 37
Restricted cash	1,500	—
Accounts receivable—trade, net	7,207	7,722
Other receivables	180	194
Inventory	990	886
Other	2,100	820
Derivative financial instruments	1,771	54
Total	14,273	9,713
Oil and natural gas properties, full cost method of accounting, net	107,531	141,911
Other property and equipment, net	14,244	14,180
Equity investment	7,820	14,588
Derivative financial instruments	615	652
Other, net	2,180	2,038
Total assets	$ 146,663	$ 183,082
LIABILITIES AND STOCKHOLDERS' DEFICIT		
Current liabilities		
Accounts payable	$ 9,373	$ 7,406
Revenue payable	4,447	4,397
Accrued expenses and other	4,928	4,055
Derivative financial instruments	4,449	1,937
Total	23,197	17,795
Derivative financial instruments	2,638	1,796
Long-term debt	57,500	92,000
Mandatorily redeemable preferred stock—6,000 shares at December 31, 2013	—	64,523
Asset retirement obligations	10,868	13,099
Other	316	75
Total liabilities	94,519	189,288
Commitments and contingencies		
Series A Cumulative Redeemable Preferred Stock, $0.01 par value; 7,250 and 1,250 shares issued and outstanding, respectively	73,152	23,828

Stockholders' equity		
Preferred stock, $0.01 par value; 5,000,000 authorized shares; 265,095 and 113,521 shares of Series B Voting Preferred Stock issued and outstanding, respectively	3	1
Common stock, $0.01 par value; 100,000,000 authorized shares; issued—21,309,159 and 29,915,951; outstanding—21,309,159 and 29,556,263, respectively	213	299
Additional paid-in capital	396,732	397,170
Treasury stock, at cost	—	(512)
Accumulated deficit	(417,956)	(426,992)
Total stockholders' deficit	(21,008)	(30,034)
Total liabilities and stockholders' deficit	$ 146,663	$ 183,082

The accompanying notes are an integral part of these statements.

Table of Contents

POSTROCK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31,		
	2011	2012	2013
	(in thousands, except per share data)		
Revenues			
Natural gas sales	$ 72,812	$ 43,911	$ 51,489
Crude oil sales	7,075	8,640	18,200
Gathering	5,239	2,444	2,611
Total	85,126	54,995	72,300
Costs and expenses			
Production expense	47,136	42,213	40,085
General and administrative	16,005	14,810	15,990
Litigation reserve	11,592	—	—
Depreciation, depletion and amortization	24,088	27,669	27,369
Impairment of oil and gas properties	—	5,919	—
(Gain) loss on disposal of assets	(10,557)	295	(194)
Acquisition costs	—	—	348
Total	88,264	90,906	83,598
Operating loss	(3,138)	(35,911)	(11,298)
Other income (expense)			
Realized gains (losses) from derivative financial instruments	33,692	73,162	(2,271)
Unrealized gains (losses) from derivative financial instruments	1,737	(66,708)	1,672
Gain (loss) from equity investment	(4,607)	(5,174)	6,768
Gain on forgiveness of debt	1,647	255	—
Other income	207	111	12
Interest expense	(10,154)	(10,454)	(3,740)
Interest income	3	2	1
Total	22,525	(8,806)	2,442
Income (loss) from continuing operations before income taxes	19,387	(44,717)	(8,856)
Income taxes	—	—	180
Income (loss) from continuing operations	19,387	(44,717)	(9,036)
Income (loss)from discontinued operations	643	(2,855)	—
Net income (loss)	20,030	(47,572)	(9,036)
Preferred stock dividends	(7,779)	(9,083)	(11,047)
Accretion of redeemable preferred stock	(1,580)	(2,238)	(3,283)
Net income (loss) available to common stockholders	$ 10,671	$ (58,893)	$ (23,366)

Net income (loss) per share common share			
Basic income (loss) per share—continuing operations	$ 1.14	$ (4.12)	$ (0.93)
Basic income (loss) per share—discontinued operations	0.07	(0.21)	—
Basic income (loss) per share	$ 1.21	$ (4.33)	$ (0.93)
Diluted income (loss) per share—continuing operations	$ 0.67	$ (4.12)	$ (0.93)
Diluted income (loss) per share—discontinued operations	0.04	(0.21)	—
Diluted income (loss) per share	$ 0.71	$ (4.33)	$ (0.93)
Weighted average common shares outstanding			
Basic	8,786	13,596	25,069
Diluted	15,050	13,596	25,069

The accompanying notes are an integral part of these statements.

Table of Contents

POSTROCK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Cash flows from operating activities			
Net income (loss)	$ 20,030	$ (47,572)	$ (9,036)
Adjustments to reconcile net income (loss) to net cash flows from operating activities			
Depreciation, depletion and amortization	27,662	30,206	27,369
Impairment of oil and gas properties	—	5,919	—
Share-based and other compensation	1,258	2,224	4,268
Amortization of deferred loan costs	1,709	2,820	461
Change in fair value of derivative financial instruments	(1,737)	67,186	(1,672)
Litigation reserve	6,042	—	—
Loss (gain) on disposal of assets	(10,560)	5,735	(194)
Gain on forgiveness of debt	(1,647)	(255)	—
Loss (gain) from equity investment	4,607	5,174	(6,768)
Other non-cash changes to items affecting net loss	618	409	497
Changes in operating assets and liabilities			
Accounts receivable	2,696	1,519	(529)
Other current assets	(1,281)	5,020	578
Other assets	(649)	33	16
Accounts payable	(2,521)	2,453	(3,094)
Accrued expenses	(3,502)	(11,701)	(512)
Other	(17)	(51)	(141)
Net cash flows from operating activities	42,708	69,119	11,243
Cash flows from investing activities			
Restricted cash	28	(1,500)	1,500
Proceeds from sale of equity securities	1,634	—	—
Equity investment	(12,883)	—	—
Expenditures for equipment, development, leasehold and pipeline	(29,338)	(16,759)	(52,283)
Proceeds from sale of discontinued pipeline	—	53,397	—
Proceeds from sale of assets	12,723	496	1,111
Net cash flows from (used in) investing activities	(27,836)	35,634	(49,672)
Cash flows from financing activities			
Proceeds from debt	3,000	57,500	98,500
Repayments of debt	(18,319)	(193,000)	(64,000)

Proceeds from stock option exercises	66	—	—
Debt and equity financing costs	—	(2,301)	(635)
Proceeds from issuance of common stock	—	20,724	4,076
Proceeds from issuance of preferred stock and warrants	—	12,500	—
Net cash flows from (used in) financing activities	(15,253)	(104,577)	37,941
Net increase (decrease) in cash and cash equivalents	(381)	176	(488)
Cash and equivalents beginning of period	730	349	525
Cash and equivalents end of period	$ 349	$ 525	$ 37

The accompanying notes are an integral part of these statements.

Table of Contents

POSTROCK ENERGY CORPORATION

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

	Preferred Shares	Preferred Stock Par Value	Common Shares Issued	Common Stock Par Value	Additional Paid-in Capital	Shares of Treasury Stock	Treasury Stock	Accumulated Deficit	Total (Deficit) Equity
	($ in thousands, except share amounts)								
Balance, December 31, 2010	195,842	$ 2	8,238,982	$ 82	$ 377,538	—	$ —	$ (390,414)	$ (12,792)
Stock-based compensation	—	—	75,169	1	1,252	—	—	—	1,253
Restricted stock grants, net of forfeitures	—	—	460,000	5	—	—	—	—	5
Issuance of Series B preferred stock	19,820	—	—	—	—	—	—	—	—
Issuance of warrants	—	—	—	—	3,763	—	—	—	3,763
Issuance of common stock, net	—	—	1,141,186	11	4,833	—	—	—	4,844
Stock option exercises	—	—	20,000	—	66	—	—	—	66
Preferred stock dividends	—	—	—	—	(7,779)	—	—	—	(7,779)
Preferred stock accretion	—	—	—	—	(1,580)	—	—	—	(1,580)
Net income	—	—	—	—	—	—	—	20,030	20,030
Balance, December 31, 2011	215,662	$ 2	9,935,337	$ 99	$ 378,093	—	$ —	$ (370,384)	$ 7,810
Stock-based compensation	—	—	—	—	2,213	—	—	—	2,213
Restricted stock grants,	—	—	1,085,104	11	—	—	—	—	11

net of forfeitures									
Issuance of Series B preferred stock	49,433	1	—	—	—	—	—	—	1
Issuance of warrants	—	—	—	—	7,405	—	—	—	7,405
Issuance of common stock, net	—	—	10,280,718	103	20,342	—	—	—	20,445
Preferred stock dividends	—	—	—	—	(9,083)	—	—	—	(9,083)
Preferred stock accretion	—	—	—	—	(2,238)	—	—	—	(2,238)
Net loss	—	—	—	—	—	—	—	(47,572)	(47,572)
Balance, December 31, 2012	265,095	$ 3	21,301,159	$ 213	$ 396,732	—	$ —	$ (417,956)	$ (21,008)
Stock-based compensation	—	—	—	—	3,213	—	—	—	3,213
Restricted stock grants, net of forfeitures and cancellations	—	—	(393,760)	(4)	—	35,166	(39)	—	(43)
Funding of 401K and deferred compensation plans	—	—	649,527	7	1,397	324,522	(473)	—	931
Warrant exchange (see Note 12)	(222,413)	(3)	1,123,981	11	(4,366)	—	—	—	(4,358)
Issuance of Series B preferred stock	70,839	1	—	—	—	—	—	—	1
Issuance of warrants	—	—	—	—	3,984	—	—	—	3,984
Issuance of common stock, net	—	—	7,235,044	72	10,540	—	—	—	10,612
Preferred stock dividends	—	—	—	—	(11,047)	—	—	—	(11,047)
Preferred stock accretion	—	—	—	—	(3,283)	—	—	—	(3,283)
Net loss	—	—	—	—	—	—	—	(9,036)	(9,036)
Balance, December 31, 2013	113,521	$ 1	29,915,951	$ 299	$ 397,170	359,688	$ (512)	$ (426,992)	$ (30,034)

The accompanying notes are an integral part of these statements.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1—Business Organization

PostRock Energy Corporation (“PostRock”) is an independent oil and gas company engaged in the acquisition, exploration, development, production and gathering of crude oil and natural gas. It manages its business in one segment, oil and gas and production. Its primary production activity is focused in the Cherokee Basin, a 15-county region in southeastern Kansas and northeastern Oklahoma, and Central Oklahoma. It also has minor oil and gas producing properties in the Appalachian Basin. Unless the context requires otherwise, any reference to “the Company”, “we”, “us”, and “our” is to PostRock and subsidiaries.

Note 2—Summary of Significant Accounting Policies

Principles of Consolidation—These consolidated financial statements include PostRock’s and its subsidiaries’ accounts. Subsidiaries in which PostRock directly or indirectly owns more than 50% of the outstanding voting securities or those in which PostRock has effective control over are generally accounted for under the consolidation method of accounting. Under this method, a subsidiaries’ balance sheet and results of operations are reflected within the Company’s consolidated financial statements. All significant intercompany accounts and transactions have been eliminated.

Use of Estimates in the Preparation of Financial Statements—The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America (“GAAP”) requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company’s most significant recurring estimates are based on remaining proved oil and gas reserves. Estimates of proved reserves are key components of the Company’s depletion rate for oil and gas properties and its full cost ceiling test limitation. In addition, estimates are used in computing fair value of impaired assets, taxes, asset retirement obligations, fair value of derivative contracts and other items. Actual results could differ from these estimates.

Cash and Cash Equivalents—The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents. Cash balances are maintained at a few financial institutions that are insured by the Federal Deposit Insurance Corporation although such balances at times are in excess of the insured amount; however, no losses have been recognized as a result of this circumstance. During 2011, the Company began utilizing a controlled disbursement cash account which is funded when outstanding checks and electronic payments are presented for payment and an overdraft is the normal book balance. The Company's policy has been to fund these outstanding checks and electronic payments as they clear through the banking system with customer receipts and borrowings under its Borrowing Base Credit Facility (as defined below). The Company accounts for such book overdrafts by reporting them in accounts and revenue payable in its consolidated balance sheets and including the change in such amounts in cash flows from operating activities in its consolidated statements of cash flows. Outstanding checks and electronic payments included in accounts and revenue payable at December 31, 2012 and 2013, amounted to $6.6 million and $4.5 million, respectively.

Accounts Receivable—The Company conducts the majority of its operations in Kansas and Oklahoma and operates exclusively in the oil and gas industry. Receivables are generally unsecured; however, the Company has not experienced any significant losses to date. Receivables are recorded at the estimate of amounts due based upon the terms of the related agreements. Management periodically assesses the accounts receivable and establishes an allowance for estimated uncollectible amounts. Accounts estimated to be uncollectible are charged to operations in the period the reserve is established. The allowance for doubtful accounts was approximately $193,000 and $194,000 at December 31, 2012 and 2013, respectively.

Inventory—Inventory includes tubular goods and other lease and well equipment which the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market using the specific identification method.

Oil and Natural Gas Properties—The Company uses the full cost method of accounting for oil and gas properties. Under the full cost method, all direct costs and certain indirect costs associated with the acquisition, exploration, and development of its oil and gas properties are capitalized.

Oil and gas properties are depleted using the units-of-production method. The depletion expense is significantly affected by the unamortized historical and future development costs and the estimated proved oil and gas reserves. Estimation of proved oil and gas reserves relies on professional judgment and use of factors that cannot be precisely determined. Subsequent proved reserve estimates that are materially different from those reported would change the depletion expense recognized during the future reporting period. No gains or losses are recognized upon the sale or disposition of oil and gas properties such will result in an amortization rate materially different from the amortization rate calculated upon recognition of gains or losses.

Under the full cost accounting rules, total capitalized costs are limited to a ceiling equal to the present value of future net revenues, discounted at 10% per annum less income tax effects (the "ceiling limitation"). The Company performs a quarterly ceiling test to evaluate whether the net book value of its full cost pool exceeds the ceiling limitation. If capitalized costs (net of accumulated depreciation, depletion, and amortization) less related deferred taxes are greater than the discounted future net revenues or ceiling limitation, a write-down or impairment of the full cost pool is required. A write-down of the carrying value of the full cost pool is a non-cash charge that reduces earnings and impacts stockholders' (deficit) equity in the period of occurrence and typically results in lower depreciation, depletion, and amortization expense in future periods. Once incurred, a write-down is not reversible at a later date. The risk that the Company will be required to write down the carrying value of its oil and gas properties increases when oil and gas prices are depressed, even if low prices are temporary. This is partially mitigated by the use of an unweighted arithmetic first day of the month price for trailing average twelve-month market prices to determine the ceiling. In addition, a write-down may occur if estimates of proved reserves are substantially reduced or estimates of future development costs increase significantly.

Unevaluated Properties—The costs directly associated with unevaluated oil and gas properties and properties under development are not initially included in the amortization base and relate to unproved leasehold acreage, seismic data, wells and production facilities in progress and wells pending determination. Unevaluated leasehold costs are transferred to the amortization base once determination has been made or upon expiration of a lease. Geological and geophysical costs and cumulative drilling costs to date associated with a specific unevaluated property are transferred to the amortization base with the associated leasehold costs on a specific project basis. Costs associated with wells in progress and wells pending determination are transferred to the amortization base once a determination is made whether or not proved reserves can be assigned to the property. All items included in the Company's unevaluated property balance are assessed on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of numerous factors, including intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, assignment of proved reserves and economic viability of development if proved reserves are assigned. Any impairments of unevaluated properties are transferred to the amortization base.

Capitalized General and Administrative Expenses—Under the full cost method of accounting, a portion of general and administrative expenses that are directly attributable to acquisition, exploration, and development activities are capitalized to the full cost pool. The capitalized costs include salaries, related fringe benefits, cost of consulting services and other costs directly associated with those activities. In addition to costs related to acquisition, exploration, and development activities, the Company has also capitalized certain software costs. The Company's capitalized general and administrative costs including software costs were $1.1 million, $904,000 and $1.3 million for the years ended December 31, 2011, 2012 and 2013, respectively.

Capitalized Interest Costs—The Company capitalizes interest based on the cost of major development projects. Capitalized interest was $51,000, $11,000 and nil for the years ended December 31, 2011, 2012 and 2013, respectively.

Other Property and Equipment—The cost of other property and equipment is depreciated over the estimated useful lives of the related assets. The cost of leasehold improvements is depreciated over the lesser of the length of the related leases or the estimated useful lives of the assets.

Upon disposition or retirement of property and equipment, other than oil and gas properties, the cost and related accumulated depreciation are removed from the accounts and the gain or loss thereon, if any, is recognized in the statement of operations in the period of sale or disposition. Maintenance and repair costs are charged to operating expense as incurred.

Impairment—Long-lived assets such as property and equipment are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of such assets may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of such assets to estimated undiscounted future cash flows expected to be generated by the assets. If the carrying amount of such assets exceeds their undiscounted estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of such assets exceeds the fair value of the assets.

Equity Investment—The Company elected to measure its investment in Constellation Energy Partners LLC (“CEP”) at fair value with changes in fair value included in the consolidated statements of operations. If the Company had not elected the fair value method, the investment would have previously qualified for the equity method of accounting, under which the Company’s proportionate share of the investee’s income would have been reported in the consolidated statements of operations.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Asset Retirement Obligations—Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 410, Asset Retirement and Environmental Obligations (ASC 410) requires that the fair value of an asset retirement cost and the corresponding liability should be recorded as part of the cost of the related long-lived asset and subsequently allocated to expense using a systematic and rational method. The Company records asset retirement obligations to reflect the Company’s legal obligations related to future plugging and abandonment of its natural gas and oil wells. Asset retirement obligations associated with the retirement of a tangible long-lived asset are recognized as a liability in the period incurred or when it becomes determinable that there is a legal or contractual obligation to dismantle or dispose of the asset and reclaim or remediate any related property at the end of its useful life, with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the asset retirement cost, is depreciated over the useful life of the asset. The asset retirement obligation is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company’s credit-adjusted risk-free interest rate. Accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. If the estimated future cost of the asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the long-lived asset. Revisions to estimated asset retirement obligations can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment. The Company has not recorded an asset retirement obligation relating to its gathering system because it does not have any legal or constructive obligations relative to asset retirements of the gathering system.

Derivative Instruments—The Company utilizes derivative instruments in conjunction with marketing and trading activities to manage price risk attributable to its forecasted sales of oil and gas production.

The Company does not designate its oil and natural gas derivative contracts as hedges under ASC 815 Derivatives and Hedging although it believes that such contracts are effective hedges of its commodity price exposure. These contracts are accounted for using the mark-to-market accounting method. Using this method, the contracts are carried at their fair value on the Company’s consolidated balance sheets under the caption “Derivative financial instruments.” Changes in the fair value of these derivative financial instruments are recorded in earnings. The Company recognizes all unrealized and realized gains and losses related to these contracts on its consolidated statements of operations under the captions “Realized gain (loss) from derivative financial instruments” and “Unrealized gain (loss) from derivative financial instruments” both which are components of “Other income (expense)”.

The Company has exposure to credit risk to the extent a counterparty to a derivative instrument is unable to meet its settlement commitment. It actively monitors the creditworthiness of each counterparty and assesses the impact, if any, on its derivative positions.

Legal—The Company is subject to certain legal proceedings, claims and liabilities which arise in the ordinary course of its business. It accrues for losses associated with legal claims when such losses are probable and can be reasonably estimated. These estimates are adjusted as additional information becomes available or circumstances change.

Revenue Recognition—Revenue from the Company's oil and gas operations is derived from the sale of produced oil and natural gas. The Company uses the sales method of accounting for the recognition of oil and gas revenue. Because there is a ready market for oil and gas, the Company sells its oil and gas shortly after production at various pipeline receipt points at which time title and risk of loss transfers to the buyer. Revenue is recorded when title and risk of loss is transferred based on the Company's net revenue interests. Gathering revenue is recognized at the time the gas is gathered or transported through the system and delivered to a third party as evidenced by a contract.

Environmental Costs—Environmental expenditures are expensed or capitalized, as appropriate, depending on future economic benefit. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and costs can be reasonably estimated. The Company has no environmental costs accrued for the periods presented.

Stock-Based Compensation—The Company grants various types of stock-based awards including stock options, restricted stock and restricted stock units to its employees and non-employee directors. The Company accounts for stock-based compensation in accordance with FASB ASC 718 Compensation – Stock Compensation where the awards are measured at fair value on the date of grant and are generally recognized as a component of general and administrative expenses in the consolidated statement of operations over the applicable requisite service periods. The fair value of stock option awards is determined using a Black-Scholes pricing model where volatility is derived from a peer group of companies.

Deferred compensation plan—The Company's deferred compensation plan permits selected employees and members of its board of directors to defer part or all of their eligible compensation. The Company accounts for this deferred compensation in accordance with FASB ASC 710 Compensation – General. The Company issues common stock into a rabbi trust created to hold the assets associated with the plan. A participant's deferred compensation is credited with earnings, gains and losses based on the Company's common stock, the only investment option currently available under the plan. The Company may also make discretionary employer credits in an amount it determines each plan year. Distributions to participants will be made in shares of the Company's common stock. Company shares held in the rabbi trust are recorded as treasury stock in the consolidated balance sheets. Since the deferred compensation arrangement currently does not permit diversification and only allows for settlement by delivery of Company common stock, the obligation is recorded as a component of paid-in-capital and changes in the fair value of the obligation are not recognized.

Income Taxes—The Company records its income taxes using an asset and liability approach in accordance with the provisions of the FASB ASC 740 Income Taxes. This results in the recognition of deferred tax assets and liabilities for the expected future tax consequences of temporary differences (primarily property and equipment and the net operating loss carry forward) between the book carrying amounts and the tax bases of assets and liabilities using enacted tax rates at the end of the period. Under FASB ASC 740, the effect of a change in tax rates of deferred tax assets and liabilities is recognized in the year of the enacted change. Deferred tax assets are reduced by a valuation allowance when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2012 and 2013, a full valuation allowance was recorded against the Company's net deferred tax assets.

The Company regularly analyzes tax positions taken or expected to be taken in a tax return based on the threshold condition prescribed under FASB ASC 740. Tax positions that do not meet or exceed this threshold condition are considered uncertain tax positions. The Company accrues interest and penalties related to uncertain tax positions as income tax expense.

Net Income (Loss) per Common Share—Basic earnings (loss) per share is calculated by dividing net income (loss) available to common stockholders by the weighted average number of shares of common stock outstanding during the period. The Company also includes contingently issuable shares in basic earnings (loss) per share when there is no circumstance under which those shares would not be issued. These include vested shares under the Company's deferred compensation plan and vested deferred restricted stock units as all necessary conditions have been satisfied for the issuance of those shares other than the passage of time. Diluted earnings (loss) per share assumes the conversion of all potentially dilutive securities (warrants, stock options and restricted stock awards) and is calculated by dividing net income (loss) by the sum of the weighted average number of shares of common stock outstanding plus potentially dilutive securities under the treasury stock method.

Concentrations of Market Risk—The Company's future results will be affected by the market price of oil and gas. The availability of a ready market for oil and gas will depend on numerous factors beyond the Company's control, including weather, production of oil and gas, imports, marketing, competitive fuels, proximity of oil and gas pipelines and other transportation facilities, any oversupply or undersupply of oil and gas, the regulatory environment, and other regional and political events, none of which can be predicted with certainty.

Concentrations of Credit Risk—Financial instruments, which subject the Company to concentrations of credit risk, consist primarily of cash and accounts receivable. Risk with respect to receivables at December 31, 2012 and 2013, arise substantially from the sales of oil and gas. The following table discloses the percentage of consolidated revenues from our major customers:

	Year Ended December 31,	
	2012	2013
British Petroleum Energy Company	22 %	56 %
ONEOK Energy and Marketing and Trading Company	34 %	11 %
Sunoco	9 %	11 %

Fair Value—The Company applies the provisions of FASB ASC 820 Fair Value Measurements and Disclosures. Fair value is the exit price that we would receive to sell an asset or pay to transfer a liability in an orderly transaction between market participants at the measurement date.

FASB ASC 820 also establishes a hierarchy that prioritizes the inputs used to measure fair value. The three levels of the fair value hierarchy are as follows:

•Level 1—Quoted prices available in active markets for identical assets or liabilities at the reporting date.

•Level 2—Pricing inputs other than quoted prices in active markets included in Level 1 which are either directly or indirectly observable at the reporting date. Level 2 consists primarily of non-exchange traded commodity derivatives.

•Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources.

The Company classifies assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. Transfers of assets and liabilities between Level 1 and Level 2 are recognized at the end of a reporting period. The Company prioritizes the use of the highest level inputs available in determining fair value.

Recent Accounting Pronouncements

In December 2011, the FASB issued Accounting Standards Update (“ASU”) 2011-11 Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities requiring entities to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on the financial position of an entity. The disclosure affects all entities with financial instruments and derivatives that are either offset on the balance sheet or subject to a master netting arrangement, irrespective of whether they are offset on the balance sheet. This information will enable users of an entity’s financial statements to evaluate the effect or potential effect of netting arrangements on an entity’s financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. The guidance is effective for annual periods beginning on or after January 1, 2013 and interim periods within those annual periods. Other than the additional disclosure requirements, which are presented in Note 6—Derivative Financial Instruments, the Company’s adoption of this guidance did not have an impact on its financial statements.

Note 3—Acquisitions and Divestitures

Acquisitions

During May 2013, we acquired leasehold interests in 4,300 acres located in Lincoln and Payne Counties in Oklahoma. The total purchase price of the acquired interests was $1.9 million which was paid in cash of $1.7 million and 126,602 shares of the Company's common stock.

During November 2013, we acquired a 50% working interest in 110 operated acres and three producing wells in Seminole County, Oklahoma, for $750,000 in cash.

During November 2013, the Company closed on an acquisition of oil and natural gas assets located in Pottawatomie, Cleveland and McClain Counties in Central Oklahoma. The acquisition included approximately 22,000 net acres of leasehold mineral interests, including certain producing oil and gas properties and related wells. The total purchase price of the acquired assets was approximately $10.0 million and was paid in cash and 4,516,129 shares of the Company's common stock. The Company estimated the fair value of the assets and liabilities acquired as of the acquisition date. The following table discloses the fair value of consideration transferred to the sellers as wells as the purchase price allocation of the assets and liabilities assumed:

Consideration given (in thousands)	
Cash	$ 3,440
Common stock	6,548
Total consideration given	$ 9,988
Amounts recognized for fair value of assets acquired and liabilities assumed	
Proved oil and natural gas properties	$ 7,081
Unproved oil and natural gas properties	3,253
Crude oil inventory	177
Accounts receivable	167
Asset retirement obligations	(538)
Accounts payable	(152)
Total fair value of oil and gas properties acquired	$ 9,988

To estimate the fair values of the properties as of the acquisition date, the Company utilized a discounted cash flow model that took into account the following inputs to arrive at estimates of future net cash flows: (i) estimated ultimate recovery of crude oil and natural gas as prepared by a third party reservoir engineering consultant; (ii) estimated future commodity prices based on NYMEX crude oil and gas futures prices as of the acquisition date and adjusted for estimated location and quality differentials; (iii) estimated future production rates; and (iv) estimated timing and amounts of future operating and development costs. To estimate the fair value of proved properties, the Company discounted the future net cash flows using a market-based rate that the Company determined appropriate at the acquisition date for the various proved reserve categories. The valuation of the assets and liabilities received is a Level 3 valuation under the fair value hierarchy. The Company has not presented pro forma information for the acquired businesses because the revenues and expenses from the acquired properties were not material to the results of operations of the Company.

Subsequent Event

During January 2014, the Company acquired additional well interests for the assets mentioned above in Pottawatomie, Cleveland, and McClain Counties in Central Oklahoma. The total purchase price of the acquired well interests was $1.8 million which was paid in cash of approximately $900,000 and 725,806 shares of the Company’s common stock.

Divestitures

KPC Sale—In September 2012, the Company sold KPC to MV Pipelines, LLC (“MV”) for $53.4 million in cash after a working capital adjustment. Details of the transaction are discussed further in Note 16 — Discontinued Operations.

Appalachia Basin Sale— On December 24, 2010, the Company entered into an agreement with Magnum Hunter Resources Corporation (“MHR”) to sell certain oil and gas properties and related assets in West Virginia. The sale closed in three phases for a total of $44.6 million. The first phase closed in December 2010 for $28 million while the following two phases closed in January and June 2011 for a combined $16.6 million. The amount received for the first and second phases was paid half in cash and half in MHR common stock, while the amount received for the third phase was paid entirely in cash.

Gains of $13.7 million and $12.5 million, net of $728,000 and $2.6 million in selling costs and adjustments, were recorded in 2010 and 2011 related to the three phases of the sale. The corresponding reduction in the Company’s oil and gas full cost pool for the three phases of the sale was $13.6 million and $1.5 million in 2010 and 2011, respectively.

Of the total proceeds received from all three phases of the sale, $6.4 million was set aside in escrow to cover potential claims for indemnity and title defects. During 2012, $5.7 million of escrowed funds relating to the first and second closing was released after net claims of $219,000 were paid. Of the $5.7 million released to the Company, $1.3 million was retained by the Company while $4.4 million was paid to Royal Bank of Canada ("RBC") under the asset sale agreement discussed in Note 10. The $219,000 of net claims paid out of escrow effectively reduced the net proceeds received from the sale, and along with certain post-closing adjustments, resulted in a $266,000 reduction in the gain on sale recognized in 2012.

At December 31, 2012, the remaining balance in escrow, which was related to the third closing, was $564,000. The escrow agreement expired by its terms on December 31, 2012, and the escrowed funds were released to MHR in January 2013.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 4—Other Balance Sheet Items

The following describes the components of the following consolidated balance sheet items at December 31, 2012 and 2013:

	December 31,	
	2012	2013
	(in thousands)	
Other current assets		
Prepaid fees and deposits	$ 1,036	$ 820
Escrowed funds from Appalachian Basin sale (1)	564	—
Escrowed funds from KPC sale (2)	500	—
Total	$ 2,100	$ 820
Other noncurrent assets, net		
Deferred financing costs	$ 1,668	$ 1,547
Noncurrent deposits and other	512	491
Total	$ 2,180	$ 2,038
Accrued expenses and other		
Interest	$ 56	$ 39
Employee-related costs and benefits	1,790	1,062
Non-income related taxes	88	72
Escrowed funds due to third parties (3)	400	—
KPC site cleanup costs (4)	313	—
Fees for services	1,327	1,127
Asset retirement obligations	—	129
Current income taxes	—	80
Other	954	1,546
Total	$ 4,928	$ 4,055
Other noncurrent liabilities		
Lease termination costs	$ 255	$ 75
Other	61	—
Total	$ 316	$ 75

(1)Escrowed funds relate to the proceeds from the Appalachian Basin sale. The escrowed funds are restricted to cover indemnities and title defects related to the sale. In 2012, $5.7 million in escrowed funds were released after $219,000 in net claims were paid. The remaining $564,000 was released to MHR in January 2013.

(2)Escrowed funds relate to the proceeds from the KPC sale and were released to the Company in January 2013 upon acceptable cleanup of a site previously owned by KPC.

(3)The balance at December 31, 2012, represented escrowed funds from the Appalachian Basin sale that were released to MHR in January 2013.

(4)Represent accrued costs for cleanup of a site previously owned by KPC as discussed above.

Deferred Financing Costs—The Company’s expense related to amortizing or writing off deferred financing costs was $1.7 million, $2.8 million and $461,000 for the years ended December 31, 2011, 2012 and 2013, respectively. These costs are included in interest expense. Included in the amounts above was a $1.2 million write-off of unamortized debt issuance costs for the year ended December 31, 2012, made in connection with the refinancing of the Company’s credit facility that year.

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 5—Property

Oil and gas properties, and other property and equipment were comprised of the following at December 31, 2012 and 2013:

	December 31, 2012	2013
	(in thousands)	
Oil and gas properties under the full cost method of accounting		
Properties being amortized	$ 353,093	$ 405,895
Properties not being amortized	31	4,862
Total oil and gas properties, at cost	353,124	410,757
Less accumulated depletion, depreciation and amortization	(245,593)	(268,846)
Oil and gas properties, net	107,531	141,911
Other property and equipment at cost	$ 30,247	$ 30,019
Less accumulated depreciation	(16,003)	(15,839)
Other property and equipment, net	$ 14,244	$ 14,180

Depreciation on other property and equipment is computed on the straight-line basis over the following estimated useful lives:

Buildings	25 years
Machinery and equipment	10 years
Software and computer equipment	3 years
Furniture and fixtures	10 years
Vehicles	5 years

For the years ended December 31, 2011, 2012 and 2013, depletion, depreciation and amortization expense on oil and gas properties amounted to $19.6 million, $23.3 million and $23.3 million, respectively. For the years ended December 31, 2011, 2012 and 2013, depreciation expense on other property and equipment amounted to $3.9 million, $3.6 million and $3.2 million, respectively. Depreciation and amortization expense on the Company's interstate pipeline that was sold in September 2012 is disclosed in Note 16. During 2011, the Company elected to shorten the depreciable lives of selected vehicle and equipment property in its pipeline segment as well as technologically limited assets, including computer hardware and communication devices, in service throughout the Company. The overall impact of this change was to increase depletion, depreciation and amortization by $0.7 million in 2011 and align the remaining depreciable lives for these assets along the lines of the demonstrated useful lives of these assets.

Note 6—Derivative Financial Instruments

The Company is exposed to commodity price risk and management believes it prudent to periodically reduce exposure to cash-flow variability resulting from this volatility. Accordingly, the Company enters into certain derivative financial instruments in order to manage exposure to commodity price risk inherent in its oil and gas production. Derivative financial instruments are also used to manage commodity price risk inherent in customer pricing requirements and to fix margins on the future sale of oil and natural gas. Specifically, the Company may utilize futures, swaps and options.

Derivative instruments expose the Company to counterparty credit risk. The Company's commodity derivative instruments are currently with two counterparties. The Company generally executes commodity derivative instruments under master agreements which allow it, in the event of default, to elect early termination of all contracts with the defaulting counterparty. If the Company chooses to elect early termination, all asset and liability positions with the defaulting counterparty would be net cash settled at the time of election.

The Company monitors the creditworthiness of its counterparties; however, it is not able to predict sudden changes in counterparties' creditworthiness. In addition, even if such changes are not sudden, it may be limited in its ability to mitigate an increase in counterparty credit risk. Possible actions would be to transfer its position to another counterparty or request a voluntary termination of the derivative contracts resulting in a cash settlement. Should one of these counterparties not perform, the Company may not realize the benefit of some of its derivative instruments under lower commodity prices as well as incur a loss. The Company includes a measure of counterparty credit risk in its estimates of the fair values of derivative instruments in an asset position. At

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

December 31, 2013, the Company was a net obligor with respect to outstanding derivative contracts with both of its counterparties and therefore utilized its own credit risk in estimating the fair value of those derivatives.

The Company entered into an International Swap Dealers Association Master Agreement ("ISDA") with each of its two counterparties for which it holds derivative contracts. The ISDA is a standard contract that governs all derivative contracts entered into between the Company and the respective counterparty. The ISDA allows for offsetting of amounts payable or receivable between the Company and the counterparty, at the election of both parties, for transactions that occur on the same date and in the same currency. The Company has multiple oil swap contracts that could be offset under these provisions but has elected not to offset the fair values of its derivative assets against the fair value of its derivative liabilities on its consolidated balance sheets. The ISDA also includes a master netting arrangement in the event of early termination or default.

The Company does not designate its derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, it recognizes the change in the respective instruments' fair value currently in earnings. The tables below outline the classification of derivative financial instruments on the consolidated balance sheet:

		December 31,	
		2012	2013
Derivative Financial Instruments	Balance Sheet Location	(in thousands)	
Commodity contracts	Current derivative financial instrument asset	$ 1,771	$ 54
Commodity contracts	Long-term derivative financial instrument asset	615	652
Commodity contracts	Current derivative financial instrument	(4,449)	(1,937)

	liability		
Commodity contracts	Long-term derivative financial instrument liability	(2,638)	(1,796)
		$ (4,701)	$ (3,027)

Gains and losses associated with derivative financial instruments related to oil and gas production were as follows for the periods indicated:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Realized gains (losses)(1)	$ 33,692	$ 73,162	$ (2,271)
Unrealized gains (losses)	1,737	(66,708)	1,672
Total gain (loss) from derivative financial instruments	$ 35,429	$ 6,454	$ (599)

____

(1)2012 includes $30.2 million received from exiting above market natural gas swap contracts originally scheduled for delivery in 2013.

The following table summarizes the estimated volumes, fixed prices and fair values attributable to all of the Company's oil and gas derivative contracts at December 31, 2013.

	Year Ending December 31,			
	2014	2015	2016	Total
	($ in thousands, except per unit data)			
Natural Gas Swaps				
Contract volumes (MMBtu)	10,327,572	8,983,560	7,814,028	27,125,160
Weighted-average fixed price per MMBtu	$ 4.01	$ 4.01	$ 4.01	$ 4.01
Fair value, net	$ (1,800)	$ (1,076)	$ (719)	$ (3,595)
Crude Oil Swaps				
Contract volumes (Bbl)	116,076	71,568	65,568	253,212
Weighted-average fixed price per Bbl	$ 95.19	$ 92.73	$ 90.33	$ 93.23
Fair value, net	$ (53)	$ 281	$ 340	$ 568
Total fair value, net	$ (1,853)	$ (795)	$ (379)	$ (3,027)

The following table summarizes the estimated volumes, fixed prices and fair values attributable to all of the Company's oil and gas derivative contracts at December 31, 2012:

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

	Year Ending December 31,				
	2013	2014	2015	2016	Total
	($ in thousands, except per unit data)				
Natural Gas Swaps					
Contract volumes (MMBtu)	3,747,285	4,324,032	3,755,184	3,765,840	15,592,341
Weighted-average fixed price per MMBtu	$ 3.95	$ 3.95	$ 3.95	$ 3.96	$ 3.95
Fair value, net	$ 1,270	$ (320)	$ (908)	$ (1,410)	$ (1,368)
Natural Gas Basis Swaps					
Contract volumes (MMBtu)	9,000,003	—	—	—	9,000,003
Weighted-average fixed price per MMBtu	$ (0.71)	$ —	$ —	$ —	$ (0.71)
Fair value, net	$ (4,448)	$ —	$ —	$ —	$ (4,448)
Crude Oil Swaps					
Contract volumes (Bbl)	65,892	61,680	58,164	53,892	239,628
Weighted-average fixed price per Bbl	$ 101.70	$ 97.00	$ 93.40	$ 91.10	$ 96.09
Fair value, net	$ 546	$ 276	$ 168	$ 125	$ 1,115
Total fair value, net	$ (2,632)	$ (44)	$ (740)	$ (1,285)	$ (4,701)

The following table discloses and reconciles the gross amounts as presented in the consolidated balance sheets to the net amounts allowed under a master netting arrangement. Amounts not offset on the condensed consolidated balance sheets represent positions that do not meet all the conditions for "a right of offset" or positions for which the Company has elected not to offset.

	December 31,	
	2012	2013
	(in thousands)	
Derivative Assets		
Gross amounts of recognized assets	$ 2,386	$ 706
Gross amounts offset in the balance sheet	—	—
Net amounts of assets presented in the balance sheet	2,386	706
Gross amounts not offset in the balance sheet	(2,386)	(706)
Net amount	$ —	$ —
Derivative Liabilities		

Gross amounts of recognized liabilities	$ 7,087	$ 3,733
Gross amounts offset in the balance sheet	—	—
Net amounts of liabilities presented in the balance sheet	7,087	3,733
Gross amounts not offset in the balance sheet	(2,386)	(706)
Net amount	$ 4,701	$ 3,027

Note 7—Financial Instruments

The Company's financial instruments include commodity derivatives, debt, cash, receivables, payables, redeemable preferred stock and equity securities. The carrying amount of cash, receivables and payables approximates fair value because of the short-term nature of those instruments.

The Company classifies assets and liabilities within the fair value hierarchy based on the lowest level of input that is significant to the fair value measurement of each individual asset and liability taken as a whole. The Company did not own any Level 3 assets or liabilities during 2012 and 2013 and there were no movements between Levels 1 and 2 for the respective time period.

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Assets and Liabilities Measured at Fair Value on a Recurring Basis—The following table sets forth, by level within the fair value hierarchy, our assets and liabilities that were measured at fair value on a recurring basis at December 31, 2012 and 2013:

	Level 1	Level 2	Level 3	Total Net Fair Value
	(in thousands)			
At December 31, 2012				
Equity investment	$ 6,984	$ 836	$ —	$ 7,820
Derivative financial instruments—assets	—	2,386	—	2,386
Derivative financial instruments—liabilities	—	(7,087)	—	(7,087)
Total	$ 6,984	$ (3,865)	$ —	$ 3,119
At December 31, 2013				
Equity investment	$ 14,205	$ 383	$ —	$ 14,588
Derivative financial instruments—assets	—	706	—	706
Derivative financial instruments—liabilities	—	(3,733)	—	(3,733)
Total	$ 14,205	$ (2,644)	$ —	$ 11,561

Commodity Derivative Instruments—The Company's oil and gas derivative instruments may consist of variable to fixed price swaps, collars and basis swaps. When possible, the Company estimates the fair values of these instruments based on published forward commodity price curves as of the date of the estimate. The discount rate used in the discounted cash flow projections is based on published LIBOR rates adjusted for counterparty credit risk. Counterparty credit risk is incorporated into derivative assets while the Company's own credit risk is incorporated into derivative liabilities. Both are based on the current published credit default swap rates.

Equity Investment—The Company owns an equity investment in CEP that was purchased in 2011. At December 31, 2013, the investment included 484,505 Class A Member Interests and 5,918,894 Class B Member Interests. Fair value for the Class B Member Interests, which are publicly traded, is based on market price and classified as a Level 1 measurement under the fair value hierarchy. Fair value for the Class A Member Interests, classified as a Level 2 measurement, is based on the market price of the publicly traded interests and a liquidity discount as the units are not publicly traded. At December 31, 2013, the fair values used for the Class A units and the Class B units were $0.79 and

$2.40 per unit, respectively.

Additional Fair Value Disclosures—The Company has 7,250 outstanding shares of Series A Cumulative Redeemable Preferred Stock (see Note 12—Redeemable Preferred Stock). At December 31, 2013, the obligation to redeem the preferred shares is reflected as debt (“Mandatorily redeemable preferred stock”) and temporary equity (“Series A Cumulative Redeemable Preferred Stock”) in the condensed balance sheet (see Note 12—Redeemable Preferred Stock). At December 31, 2012, the entire obligation was reflected in temporary equity in the balance sheet. The fair value and the carrying value of these securities at December 31, 2012, were $91.3 million and $73.2 million, respectively. The fair value and the carrying value of these securities at December 31, 2013, were $30.9 million and $23.8 million, respectively for the portion reflected as temporary equity and $71.9 million and $64.5 million, respectively, for the portion reflected in debt. The fair value was determined by discounting the cash flows over the remaining life of the securities utilizing a LIBOR interest rate and a risk premium of approximately 7.1% and 12.9% at December 31, 2012 and 2013, respectively, which was based on companies with similar leverage ratios to PostRock. The Company has classified the valuation of these securities under Level 2 of the fair value hierarchy.

The Company’s long term debt consists entirely of floating-rate facilities. The carrying amount of floating-rate debt approximates fair value because the interest rates paid on such debt are generally set for periods of six months or shorter.

Note 8—Equity Investment

The Company elected the fair value option to account for its interest in CEP. The fair value option was chosen as the Company determined that the market price of CEP’s publicly traded interests provided a more accurate fair value measure of the Company’s investment in CEP. The Company has not elected the fair value option for any of its other assets and liabilities.

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The following table presents the mark-to-market gains (losses) on our equity investment, which are recorded as a component of other income (expense) in the consolidated statement of operations:

	Year ended December 31,		
	2011	2012	2013
	(in thousands)		
Mark to market gains (losses) on equity investment	$ (4,607)	$ (5,174)	$ 6,768

The following table presents summarized condensed financial information of CEP.

	Year ended December 31,		
	2011	2012	2013
	(in thousands)		
Gross revenues	$ 105,217	$ 59,335	$ 46,381
Gross profit (loss)(1)	29,453	(80,964)	(25,589)
Net income (loss) from continuing operations (2)	—	(9,462)	(25,857)
Net income (loss)	19,586	(86,543)	(28,543)

(1) Equals revenues less operating expenses
(2) Net income from continuing operations is not available for 2011

On August 9, 2013, CEP announced that it had closed the transactions contemplated by a Contribution Agreement (the "Contribution Agreement") with Sanchez Energy Partners I, LP ("Sanchez") pursuant to which Sanchez agreed to sell to CEP all of the equity of an entity that owns oil and natural gas properties located in Texas and Louisiana in exchange for consideration consisting of 4,724,407 CEP Class B units, 1,130,512 CEP Class A Units, one CEP Class Z Unit and $20,090,876 in cash, for an aggregate purchase price of approximately $30.4 million. CEP also announced that Sanchez, as the holder of a majority of the Company's Class A Units, removed John R. Collins and Gary M. Pittman as the Company's Class A managers and elected Antonio R. Sanchez, III and Gary Willinger to the CEP's Board of

Managers to serve as the Class A managers.

On August 30, 2013, CEPM, a wholly owned subsidiary of the Company, together with Gary M. Pittman and John R. Collins, as Plaintiffs, filed suit in the Delaware Court of Chancery against CEP, CEP's Chief Executive Officer, Stephen R. Brunner, Richard S. Langdon, Richard H. Bachmann and John N. Seitz, each a member of the five-person CEP Board of Managers, Sanchez Oil & Gas Corporation and Sanchez Energy Partners I, LP (collectively, the "Sanchez Defendants"), Antonio R. Sanchez, III and Gerald F. Willinger, as Defendants (Case No. 8856-VCL).

The lawsuit arises from actions taken by the Defendants prior to and during the August 9, 2013, meeting of the CEP Board of Managers. Specifically, the lawsuit alleges that the Defendants conspired to dilute CEPM's ownership interest in CEP and thereby remove CEPM's right, as the sole owner of Class A units, to select two Managers to the CEP Board of Managers. At the time of the August 9th meeting, Pittman and Collins were serving as CEPM's duly selected members on the CEP Board of Managers.

The suit asserts that by purporting to issue to the Sanchez Defendants 4,724,407 Class B units and 1,130,512 Class A units in connection with CEP's purchase of the oil and gas properties, the Defendants acted in bad faith, violated CEP's Operating Agreement, wrongfully interfered with CEPM's contractual relations, and breached contractual and fiduciary obligations owed to CEPM. As such, the complaint further alleges that the Sanchez Defendants were without authority to remove Pittman and Collins as the Class A unit representatives on the Board of Managers and purportedly replace them with Defendants Sanchez and Willinger. Among other relief, Plaintiffs seek a declaration that the purported issuance of units to the Sanchez Defendants violates the CEP operating agreement and is therefore invalid and void. Plaintiffs also seek to have Pittman and Collins reinstated to the CEP Board of Managers. Trial was initially scheduled for mid-December 2013, but has been postponed indefinitely based on anticipated settlement in early 2014.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 9—Asset Retirement Obligations

The following table reflects the changes to asset retirement obligations for the periods indicated:

	Year Ended December 31, 2012	Year Ended December 31, 2013
	(in thousands)	
Asset retirement obligations at beginning of period (1)	$ 10,087	$ 10,868
Liabilities incurred	160	533
Liabilities settled	(111)	(88)
Acquisitions	—	538
Accretion	743	811
Revision of estimates	(11)	566
Asset retirement obligations at end of period	$ 10,868	$ 13,228
Current portion of asset retirement obligations	$ —	$ 129
Noncurrent portion of asset retirement obligations at end of period	$ 10,868	$ 13,099

(1)Amounts in the table do not include the asset retirement obligations of KPC which was divested by the Company during 2012.

During 2013, revisions to the Company's asset retirement obligations totaled $566,000. The increase is due to higher estimated cost to plug an oil/gas well, salt water disposal (SWD) well, as well as a tank battery remediation costs.

Note 10—Long-Term Debt

The following is a summary of long-term debt at the dates indicated:

	December 31,	
	2012	2013
	(in thousands)	
Borrowing Base Facility	$ 57,500	$ 92,000
Less current maturities	—	—
Total long-term debt	$ 57,500	$ 92,000

Borrowing Base Facility

The Company's sole credit facility is the Third Amended and Restated Credit Agreement, dated as of December 20, 2012 (the "Borrowing Base Facility"), among PostRock Energy Services Corporation ("PESC") and PostRock MidContinent Production, LLC ("MidContinent"), as borrowers, Citibank, N.A., as successor administrative and collateral agent, Royal Bank of Canada, as resigning administrative and collateral agent, and the lenders and other loan parties party thereto. The Borrowing Base Facility is a $200 million senior secured revolving facility guaranteed by the Company and its subsidiaries other than the borrowers and Constellation Energy Partners Management, LLC (the "Excluded Subsidiary"). At December 31, 2013, the borrowing base under the Borrowing Base Facility was $115.0 million, an increase from the borrowing base of $90.0 million at December 31, 2012. With outstanding borrowings of $92.0 million and letters of credit of $1.3 million, $21.7 million was available for additional borrowings at December 31, 2013,

Material terms of the Borrowing Base Facility include the following:

Covenants. The Borrowing Base Facility contains affirmative and negative covenants that are customary for transactions of this type, including financial covenants that prohibit the Company and any of its subsidiaries (other than the Excluded Subsidiary) from:

•permitting the ratio of consolidated current assets of the Company and its subsidiaries (excluding the Excluded Subsidiary) to consolidated current liabilities, after certain adjustment, at any fiscal quarter-end to be less than or equal to 1.0 to 1.0;

•permitting the Company's interest coverage ratio (ratio of consolidated EBITDAX (as defined in the Borrowing Base Facility) to consolidated interest charges) at any fiscal quarter-end to be less than or equal to 3.0 to 1.0 measured on a trailing four quarter basis; and

Table of Contents

•permitting the Company’s leverage ratio (ratio of consolidated funded debt to consolidated EBITDAX for the four fiscal quarters ending on the applicable fiscal quarter-end) to be greater than to 3.5 to 1.0.

Interest Rate. LIBOR plus 2.50% to 3.25% or, at the borrowers’ option, Base Rate (as defined) plus 1.5% to 2.25%, in each case depending on utilization. The interest rate on outstanding borrowings on December 31, 2013 was 3.17%.

Maturity Date. December 20, 2016.

Borrowing Base Redetermination. Borrowing base redeterminations by the lenders will be effective every May 1st and November 1st until maturity taking into account the value of MidContinent’s proved reserves. In addition, during each period between scheduled redeterminations of the borrowing base, the borrowers and the administrative agent, respectively, have the right to initiate a redetermination of the borrowing base between each scheduled redetermination, provided that no more than two such redeterminations may occur in a 12-month period. In addition, upon a material disposition of assets and a material acquisition of oil and gas properties, and in certain other limited circumstances, the borrowing base will or may be redetermined. If the borrowing base is reduced in connection with a redetermination, the borrowers can elect to either repay the entire deficiency within 30 days, repay the deficiency in six equal monthly installments, or contribute additional properties to increase the value of the collateral to support the prior borrowing base.

Payments. The aggregate principal amount of all outstanding revolving loans is required to be repaid on the maturity date. The borrowers are required to make a mandatory prepayment upon the occurrence of any of the following events: (a) a material disposition of oil and gas properties; (b) a change of control; (c) the existence of a borrowing base deficiency; (d) a sale of assets whose proceeds exceed 5% of the borrowing base then in effect; (e) the issuance or incurrence of indebtedness by any loan party not otherwise permitted under the Borrowing Base Facility; and (f) certain equity issuances. Interest payments are due (i) at the end of each LIBOR interest period, but in no event less frequently than quarterly in the case of LIBOR loans or (ii) quarterly in the case of Base Rate loans.

Security Interest. The Borrowing Base Facility is secured by a first lien on substantially all of the assets of the Company and its subsidiaries other than the Excluded Subsidiary and its assets.

Events of Default. Events of default are customary for transactions of this type and include, without limitation, non-payment of principal when due, non-payment of interest, fees and other amounts within three business days after the due date, failure to perform or observe covenants and agreements (subject to a 30-day cure period in certain cases), representations and warranties not being correct in any material respect when made, certain acts of bankruptcy or insolvency, cross defaults to other material indebtedness, non-appealable judgment in a material amount is entered against a borrower or its affiliate, ERISA violations, invalidity of loan documents, dissolution, collateral impairment, existence of any borrowing base deficiency beyond any permitted grace periods, and change of control.

The Company's leverage ratio at December 31, 2013 was slightly greater than the allowed 3.5 to 1.0. The Company has obtained a waiver of noncompliance as of December 31, 2013 from the required lenders under the Borrowing Base Facility. The Company was in compliance with all other financial covenant ratios as of December 31, 2013.

QER Loan

The QER Loan was a former credit facility collateralized by a first priority lien on all the assets of PostRock Eastern Production, LLC, formerly named Quest Eastern Resource LLC ("QER"). In connection with the restructuring of the Company's credit facilities in 2010, the Company entered into an asset sale agreement with RBC that allowed the Company to sell QER, or its assets and, in the event the proceeds were not adequate to repay the QER Loan in full, the Company agreed to pay a portion of such shortfall in cash, stock or a combination thereof.

As discussed in Note 3, the Company sold certain Appalachian Basin oil and gas properties to MHR in three phases that closed in December 2010, January 2011 and June 2011. Included in the $44.6 million total was approximately $41.6 million representing the purchase price of assets owned by QER pledged as collateral under the QER Loan. From the sale proceeds, QER made payments to the lender, RBC, in the amount of $21.2 million in December 2010, $9.3 million in January 2011 and $4.3 million in June 2011. Concurrent with the June 2011 payment and pursuant to the terms of the asset sale agreement with RBC, the Company fully settled the outstanding balance of the QER Loan of approximately $843,000 by issuing 141,186 shares of its common stock with a fair value of $744,000 to RBC. The settlement also included the future remittance of a portion of the sale proceeds scheduled to be released from the escrow in June 2012. In June 2012, $5.7 million of the escrowed proceeds was released to the Company, of which $1.3 million

Table of Contents

was retained by the Company while $4.4 million was paid to RBC, representing the final payment in connection with the QER Loan. Included in the amount released to the Company was a recovery by the Company of the $843,000 payment to RBC made in June 2011.

The settlement of the QER Loan was facilitated by the restructuring of a prior loan that met the criteria under accounting guidance to be classified as a troubled debt restructuring. The Company had previously recorded gains on debt restructuring related to the QER Loan of $2.9 million in 2010 and $1.6 million in 2011. The gain in 2011 included $799,000 of accrued interest that was forgiven at the time the balance of the loan was settled. As a result of the Company's final evaluation of all payments made to RBC in connection with the QER Loan, an additional gain on debt restructuring of $255,000 was recorded in 2012. These gains are reflected as a "gain on forgiveness of debt" in the consolidated statement of operations.

Deferred Financing Costs

In connection with the closing of the Borrowing Base Facility on December 20, 2012, the Company incurred $1.7 million in financing costs that were capitalized and will be amortized over the four-year life of the facility. In conjunction with the closing of the Borrowing Base Facility, the Company's prior credit facility was settled and $1.2 million in remaining unamortized deferred financing costs associated with the prior facility was written off.

Note 11—Income Taxes

The Company has not recorded any provision or benefit for income taxes for the years ended December 31, 2011, and 2012. For 2013, the Company has recorded a tax expense of $180,000. During 2013 the Company settled an IRS exam relating to the 2011 tax year which resulted in current tax expense of $30,000. The Company also recorded $70,000 of tax expense related to the current tax year. All of the tax expense recorded in 2013 is alternative minimum tax, which creates an alternative minimum tax credit carryforward. The Company has recorded a valuation against the alternative minimum tax credit carryforward.

A reconciliation of federal income taxes at the statutory federal rates to our actual provision for income taxes is as follows:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Income tax expense (benefit) at statutory rate	$ 7,011	$ (16,650)	$ (3,100)
State income tax expense (benefit), net of federal	647	958	19
Effect of the Recombination	—	—	—
2011 IRS Settlement	—	—	30
Other	2,942	1,650	496
IRC Section 382 limitation	(2,135)	30,491	2,575
Change in valuation allowance	(8,465)	(16,449)	160
Total tax expense (benefit)	$ —	$ —	$ 180

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax reporting. Deferred tax assets are reduced by a valuation allowance if it is deemed more likely than not that some or all of the deferred assets will not be realized based on the weight of all available evidence. Based on the negative evidence that existed at each reporting period, the Company recorded a full valuation allowance against its net deferred tax asset at December 31, 2011, 2012, and 2013.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Deferred tax assets and liabilities at December 31, 2012 and 2013 were as follows:

	Year Ended December 31,	
	2012	2013
	(in thousands)	
Current deferred income tax assets		
Unrealized loss for commodity derivative recorded for book, not for tax	$ 1,658	$ 722
Accrued liabilities	1,047	1,038
Allowance for bad debts	72	72
Other	630	277
Total current deferred income tax assets	3,407	2,109
Noncurrent deferred income tax assets		
Unrealized loss for commodity derivative recorded for book, not for tax	983	669
Partnership basis differences	6,037	6,287
Property and equipment	45,733	37,849
Asset retirement obligations	1,871	2,173
Net operating loss carryforwards	18,459	14,943
Other carryforwards	1,516	2,264
Total noncurrent deferred income tax assets	74,599	64,185
Total deferred income tax assets	78,006	66,294
Current deferred income tax liabilities		
Unrealized gain for commodity derivative recorded for book, not for tax	(11,905)	(20)
Other	—	—
Total current deferred income tax liabilities	(11,905)	(20)
Noncurrent deferred income tax liabilities		
Unrealized gain for commodity derivative recorded for book, not for tax	(407)	(420)
Total noncurrent deferred income tax liabilities	(407)	(420)
Total deferred income tax liabilities	(12,312)	(440)
Net deferred income tax assets	65,694	65,854
Valuation allowance	(65,694)	(65,854)
Total deferred tax asset (liability)	$ —	$ —

The Company has net operating loss (“NOL”) carryforwards that are available to reduce future U.S. taxable income. If not utilized, such carryforwards will expire from 2025 through 2033.

The Company's ability to utilize NOL carryforwards to reduce future federal taxable income and federal income tax of the Company is subject to various limitations under Internal Revenue Code ("IRC") Section 382. The utilization of such carryforwards may be limited upon the occurrence of certain ownership changes, including the issuance or exercise of rights to acquire stock, the purchase or sale of stock by 5% stockholders, as defined in the Treasury regulations, and the offering of stock of PostRock during any three-year period resulting in an aggregate change of more than 50% in the beneficial ownership of PostRock. The Company experienced ownership changes within the meaning of IRC Section 382 on November 14, 2005, March 5, 2010, and September 21, 2010. The Company has NOL carryforwards of approximately $237 million at December 31, 2013 that are available to reduce future U.S. taxable income in certain circumstances. At December 31, 2013, $228 million of federal NOL carryforwards are subject to the IRC Section 382 limitation and it is anticipated that $210 million of these federal NOL carryforwards will expire unused due to the IRC Section 382 limitation. As a result, only $27 million of federal NOL carryforwards have been recorded as a deferred tax asset. The limitation does not result in a current federal tax liability for the period ended December 31, 2013.

In addition to the restrictions imposed on the Company's NOL carryforwards under IRC Section 382, the Company also had a net unrealized built-in loss in its assets at the date of the ownership changes. IRC Section 382 generally restricts the Company's ability to utilize any recognized built-in losses ("RBILs") which are recognized during the 5-year period following an ownership change. The Company has recognized tax depreciation and depletion and tax losses on the disposition of its built-in loss assets during 2010, 2011, 2012 and 2013 of approximately $96.1 million. Of this amount, only $3.5 million was allowed to be deducted in the year incurred. The remaining RBILs of $92.6 million are allowed to be carried forward in a manner similar to NOLs, subject to limitation under IRC

Section 382. It is anticipated that approximately $89.4 million of these RBIL carryforwards will expire unused due to the IRC Section 382 limitation. As a result, only $3.2 million of RBILs have been recorded as a deferred tax asset.

FASB ASC 740-10 provides guidance for recognizing and measuring uncertain tax positions. Based upon the provision of FASB ASC 740-10, the Company did not record any amounts for uncertain tax benefits upon adoption of the standard and has no amounts recorded for uncertain tax benefits at December 31, 2013. Accordingly, there has been no change in unrecognized tax benefits during the year. The Company files income tax returns in the U.S. federal jurisdiction and various state and local jurisdictions. Tax years ended December 31, 2010, 2011 and 2012 remain open for examination by the relevant taxing authorities. In addition, the Company's tax returns for the tax years ended May 31, 2000, through December 31, 2009, can be examined and adjustments made to the amount of net operating losses flowing from those years into an open tax year. However, no assessment of income tax may generally be made for those years on which the statute has closed. The Company's policy is to recognize interest and penalties, if any, related to unrecognized tax benefits as income tax expense.

Note 12—Redeemable Preferred Stock and Warrants

On September 21, 2010, the Company issued to White Deer Energy L.P. and its affiliates ("White Deer") 6,000 shares of the Company's Series A Cumulative Redeemable Preferred Stock (the "Series A Preferred Stock"), 190,476.19 shares of its Series B Voting Preferred Stock (the "Series B Preferred Stock") and warrants to purchase 19,047,619 shares of the Company's common stock. The preferred stock and warrants were issued in exchange for $60 million. During 2012, the Company issued additional shares of Series A Preferred Stock and warrants to White Deer in two separate transactions. The first transaction, which closed in August 2012, included 600 shares of Series A Preferred Stock with $6.0 million initial liquidation preference along with warrants to purchase 3,076,923 shares of common stock at an exercise price of $1.95 a share. These securities were issued for proceeds of $6.0 million. The second transaction, which closed in December 2012, included 650 shares of Series A Preferred Stock with $6.5 million initial liquidation preference along with warrants to purchase 4,577,464 shares of common stock at an exercise price of $1.42 a share. These securities were issued for proceeds of $6.5 million. The terms of the Series A Preferred Stock and warrants issued in 2012 are substantially the same as those in White Deer's original September 2010 investment except as discussed below.

The investments discussed above were recognized on the Company's consolidated balance sheet based on the relative fair values of the Series A Preferred Stock and the warrants allocated to the proceeds. The allocation results in an increase to the Company's temporary equity related to the Series A Preferred Stock and an increase to additional paid in capital related to the warrants issued.

The Series A Preferred Stock is entitled to a cumulative dividend of 12% per year on its liquidation preference, compounded quarterly. The liquidation preference will increase by the amount of dividends paid in kind. Changes in the liquidation value are disclosed in the table below. The Company is not required to pay cash dividends until December 31, 2014. Any dividends prior to that time not paid in cash will accrue as additional liquidation preference. Subsequent to December 31, 2014, dividends are required to be paid in cash, subject to the legal availability of funds for the declaration and payment thereof, and any payment default after that date will increase the accrual of the additional liquidation preference during the default period to 14%. The Company is required to redeem the Series A Preferred Stock on March 21, 2018, at 100% of the liquidation preference. From and after one year from the issuance date until such mandatory redemption date, the Company will have the option to redeem all or a specified minimum portion of the Series A Preferred Stock at 110% of the liquidation preference. The holders of the Series A Preferred Stock have the right to require the Company to purchase their shares on the occurrence of specified change in control events at 110% of the liquidation preference. In the case of specified defaults by the Company, including the failure to pay dividends for any quarterly period after December 31, 2014, and until the defaults are cured, the holders of the Series A Preferred Stock have the right to appoint two additional directors to the Board of Directors. The Series A Preferred Stock does not vote generally with the common stock, but has specified approval rights with respect to, among other things, changes to the Company’s certificate of incorporation that affect the Series A Preferred Stock, cash dividends on the common stock or other junior stock, redemptions or repurchases of common stock or other capital stock, increases in the size of the Board of Directors, changes to specified debt agreements and changes to the Company’s business.

With respect to the Series A Preferred Stock issued on September 21, 2010, prior to December 31, 2014, if dividends are not paid in cash on a dividend payment date, the Company will issue additional warrants exercisable for a number of shares of common stock equal to the amount of dividends that are not paid on that dividend payment date divided by the closing price of the common stock on the trading date immediately preceding the dividend payment date. The exercise price of the warrants will be such closing price. The warrants, including any additional warrants, are exercisable for 90 months following the applicable issuance date. Each warrant is coupled, and may only be transferred as a unit, with a number of one one-hundredths of a share, or a “fractional share,” of Series B Preferred Stock equal to the number of shares of common stock purchasable upon exercise of the warrant. The warrants and the Series B Preferred Stock may not be transferred separately. If and when the warrant is exercised, the holder of the warrant will be required to deliver to the Company, as part of the payment of the exercise price, a number of fractional shares of Series B Preferred Stock equal to the number of shares of common stock purchased upon such exercise. The holders of the warrants have the right to pay the exercise price in cash, by electing a cashless exercise (whereby the holder will receive the excess of the market price of the common stock over the exercise price in shares of common stock valued at the market price) or by tendering shares of Series A Preferred Stock with a liquidation preference equal to the exercise price. If the market price of the common stock exceeds 300% of the exercise price for a specified period of time and other conditions are satisfied, the Company may require the holders of the warrants to exercise warrants to purchase up to 50% of shares covered thereby, but in the aggregate not less than 750,000 shares or more than 50% of the trading volume of the common stock over the preceding 20 trading days.

With respect to the warrants issued in conjunction with the Series A Preferred Stock in August 2012 and December 2012, including those that may be issued on future pay-in-kind dividends on this preferred stock, the terms are otherwise similar to those issued in September 2010 except they are not coupled with a fractional share of Series B Preferred Stock (and therefore have no voting right attached) and all of those warrants will have an exercise price of \$1.95 a share and \$1.42 a share, respectively, rather than the market price at the time of issuance.

The holders of Series B Preferred Stock are entitled to vote in the election of directors and on all other matters submitted to a vote of the holders of common stock of the Company, with the holders of Series B Preferred Stock and the holders of common stock voting together as a single class. Each fractional share of Series B Preferred Stock has one vote. The voting rights of each share of Series B Preferred Stock may not be exercised by any person other than the holder of the warrant that is part of the unit with such share or fractional share and will expire on the expiration date of such warrant. The Series B Preferred Stock has no dividend rights and a nominal liquidation preference. With respect to the votes applicable to the Series B Preferred Stock, the holders of the Series B Preferred Stock and their affiliates are limited to 45% of the votes applicable to all outstanding voting stock; such holders and their affiliates may vote any shares of common stock held by them without regard to that limit.

When the Company accrues dividends on its Series A Preferred Stock on a quarterly dividend payment date, it records the increase in liquidation preference and the issuance of additional warrants by allocating their relative fair values to the amount of accrued dividends. The allocation results in an increase to the Company’s temporary equity related to the Series A Preferred Stock and an increase to additional paid in capital related to the additional warrants issued.

The Series A Preferred Stock has been recorded outside of permanent equity and liabilities, in the Company’s consolidated balance sheet because the settlement provisions of the warrants allow White Deer to “net exercise” the warrants by requiring the Company to repay the Series A Preferred Stock at the liquidation preference to offset the strike price of the warrants that would otherwise be due from White Deer in cash. Absent this provision, the Series A Preferred Stock would have met the definition of mandatorily redeemable preferred stock under FASB ASC 480 Distinguishing Liabilities from Equity which would have required recognition as a liability. This provision allows the Series A Preferred Stock to effectively be convertible to common stock at the election of White Deer. In the event that White Deer exercises the warrants without net-exercising the Series A Preferred Stock back to the Company as payment for the strike price of the warrants, the Company will be required to reclassify a proportionate amount of Series A Preferred Stock from temporary equity to liabilities as that portion of the Series A Preferred Stock is no longer convertible to common stock and thus has become mandatorily redeemable.

In December 2013, the Company closed on a Warrant Exchange Agreement with White Deer pursuant to which the Company issued to White Deer 1,123,981 shares of its common stock with a fair value of $1.5 million in exchange for the following securities of the Company held by the White Deer: warrants exercisable for 22,241,333 shares of common stock (the “Warrants”) together with a like number of one one-hundredths of a share of Series B Voting Preferred Stock that were issued as a unit with the Warrants (collectively, the “Warrant Exchange”). The Warrants had exercise prices ranging from $2.80 to $6.39 per share, with a weighted average exercise price of $3.23 per share. The number of shares issued was calculated based on the Black-Scholes model. With the exchange and retirement of the Warrants, the likelihood that the portion of the liquidation preference on the Series A Preferred Stock will be utilized for a cashless exercise of the Warrants ceases to exist. Accordingly, that portion of the Series A Preferred Stock liquidation preference is no longer convertible to common stock and now becomes mandatorily redeemable. Pursuant to applicable accounting guidance, the Company reclassified $64.5 million out of temporary and permanent equity into liabilities representing the fair value of the Series A Preferred Stock liquidation preference that became mandatorily redeemable. No gain or loss was recognized as a result of the reclassification. The fair value of the reclassified mandatorily redeemable portion was determined by discounting the cash flows over the remaining life of the securities utilizing a LIBOR interest rate corresponding to the applicable maturity and a risk premium of 13.7%, which was based on companies with similar leverage ratios to PostRock. The Company has classified this valuation under Level 2 of the fair value hierarchy. Subsequent to the reclassification, dividends and accretion related to the reclassified Series A Preferred Stock will be recorded as interest expense for which $497,000 was recognized for the year ended December 31, 2013. However, when dividends on the mandatorily redeemable portion are paid in kind in the future through an increase in liquidation preference and additional issuance of warrants, the increase in liquidation preference is recorded to temporary

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

equity rather than liabilities as it still retains the potential of being used for a cashless exercise of the warrants and hence deemed to be conditionally redeemable.

The following table summarizes changes in the Series A Preferred Stock and associated warrants:

	Carrying Value of Series A Preferred Stock in Temporary Equity	Carrying Value of Series A Preferred Stock in Liabilities	Number of Outstanding Series A Preferred Shares	Liquidation Value of Series A Preferred Stock	Number of Outstanding Warrants	Weighted Average Exercise Price of Warrants
	(in thousands except share, warrant and per unit data)					
December 31, 2010	$ 50,622	$ —	6,000	$ 61,980	19,584,205	$ 3.16
Accrued dividends	4,534	—	—	7,779	1,982,040	3.92
Accretion	1,580	—	—	—	—	—
December 31, 2011	56,736	—	6,000	69,759	21,566,245	3.23
Issuance	8,428	—	1,250	12,500	7,654,387	1.63
Accrued dividends	5,750	—	—	9,083	5,115,782	1.78
Accretion	2,238	—	—	—	—	—
December 31, 2012	73,152	—	7,250	91,342	34,336,414	2.66
Accrued dividends	7,479	—	—	11,047	8,066,270	1.42
Accrued dividends recorded as interest	—	—	—	417	—	—
Warrant Exchange	(60,086)	64,443	—	—	(22,241,333)	3.23
Accretion	3,283	80	—	—	—	—
December 31, 2013	$ 23,828	$ 64,523	7,250	$ 102,806	20,161,351	$ 1.54

The following table summarizes changes to additional paid in capital (“APIC”) as a result of warrants issued to White Deer:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Warrants issued in conjunction with issuance of Series A Preferred Stock	$ —	$ 4,071	$ —
Warrants issued in conjunction with paid-in-kind dividends	3,245	3,334	3,984
Total change in APIC due to warrants issued	$ 3,245	$ 7,405	$ 3,984

Note 13—Equity and Earnings per Share

Restricted share and stock option grants to employees and non-employee directors is governed by PostRock's 2010 Long-Term Incentive Plan (the "LTIP") of which 10,850,000 shares have been authorized for awards.

The Company's employee share based grants, including restricted shares and options, have generally vested 33% a year for three years or have vested in one year when awarded in conjunction with the Company's annual bonus program. Share based grants to non-employee directors have generally vested immediately or in one year.

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

A summary of changes in the non-vested restricted shares or share units for PostRock and its Predecessors for the periods presented is below:

	Number of Non-Vested Restricted Shares	Weighted Average Grant Date Fair Value
Non-vested restricted shares at December 31, 2010	375,358	$ 4.83
Granted	487,500	2.90
Vested	(80,554)	5.91
Forfeited	(203,094)	5.08
Non-vested restricted shares at December 31, 2011	579,210	3.33
Granted	1,295,112	2.01
Vested	(275,900)	3.23
Forfeited	(118,856)	3.76
Non-vested restricted shares at December 31, 2012	1,479,566	2.16
Granted	641,902	1.75
Vested	(452,529)	2.79
Cancelled/Forfeited (1)	(1,053,673)	1.79
Non-vested restricted shares at December 31, 2013	615,266	$ 1.89

(1) 787,414 shares were cancelled with an associated accelerated stock compensation expense of approximately $500,000.

At December 31, 2013, total unrecognized stock-based compensation expense related to non-vested restricted shares was $444,000, which is expected to be recognized over a weighted average period of approximately 1.23 years while 7,208,111 shares were available under the LTIP for future stock awards and options.

Stock Options—The LTIP also provides for the granting of options to purchase shares of PostRock's common stock. The Company has in the past granted stock options to employees and non-employees. Option grants under the LTIP expire

5-6 years following the date of grant.

A summary of changes in stock options outstanding for PostRock and its Predecessors is presented below:

	Stock options	Weighted Average Exercise Price per Option	Weighted Average Grant Date Fair Value per Option
Options outstanding at December 31, 2010	567,050	$ 4.17	
Granted	799,400	3.63	$ 2.15
Exercised (1)	(20,000)	3.29	
Forfeited or expired	(289,600)	4.07	
Options outstanding at December 31, 2011	1,056,850	3.59	
Granted	1,303,653	1.80	1.07
Forfeited or expired	(190,220)	4.30	
Options outstanding at December 31, 2012	2,170,283	2.45	
Granted	584,949	1.77	0.89
Forfeited or expired	(448,813)	1.92	
Options outstanding at December 31, 2013	2,306,419	2.38	
Exercisable			
Options exercisable at December 31, 2011	310,922	$ 5.57	
Options exercisable at December 31, 2012	467,189	4.10	
Options exercisable at December 31, 2013	989,037	3.03	

(1)The Company received $66,000 upon exercise of these options which had a total intrinsic value of $34,000 at the exercise dates.

The weighted average remaining term of options outstanding and options exercisable at December 31, 2013, was 3.52 and 3.08 years, respectively. Both options outstanding and options exercisable at December 31, 2013, had aggregate intrinsic values of nil.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The Company determines the fair value of stock option awards using the Black-Scholes option pricing model. As the Company does not have sufficient historical exercise or post-vesting termination experience, the Company currently uses an expected option term of four years, which is the average of the vesting term and the original contractual term. The expected forfeiture rate was estimated based upon historical forfeiture experience. The volatility assumption was estimated based upon expectations of volatility over the life of the option as measured by historical and implied volatility of peer companies. The risk-free interest rate was based on the U.S. Treasury rate for a term commensurate with the expected life of the option. The dividend yield was based upon a 12-month average dividend yield.

The Company used the following assumptions to estimate the fair value of stock options granted during the years ending December 31, 2011, 2012 and 2013.

	2011	2012	2013
Expected option life-years	5-6	5	4
Volatility	74.4 - 77.0 %	74.3 - 76.1 %	64.0 - 82.7 %
Risk-free interest rate	0.9 - 2.0 %	0.9 - 1.3 %	0.6 - 1.4 %
Dividend yield	—	—	—
Fair value per share	$ 1.43 - 4.53	$ 0.87 - 1.88	$ 0.82 - 1.03

At December 31, 2013, there was $665,000 of total unrecognized compensation cost related to stock options which is expected to be recognized over a weighted average period of 1.27 years.

Total share-based compensation covering stock awards and options is included in general and administrative expense on the consolidated statement of operations and is disclosed below for the periods presented:

	Total Share Based Compensation Expense
	(in thousands)
Year Ended December 31, 2011	$ 1,258
Year Ended December 31, 2012	2,224
Year Ended December 31, 2013	3,177

Income/(Loss) per Share — A reconciliation of the denominator (number of shares) used in the basic and diluted per share calculations for the periods indicated is as follows:

	Year Ended December 31,		
	2011	2012	2013
Denominator for basic earnings per share (1)	8,785,551	13,595,843	25,068,574
Effect of potentially dilutive securities			
Unvested share-based awards	127,600	—	—
Warrants	6,089,339	—	—
Stock options	47,230	—	—
Denominator for diluted earnings per share	15,049,720	13,595,843	25,068,574
Securities excluded from earnings per share calculation			
Unvested share-based awards	14,998	149,988	—
Antidilutive stock options	1,056,850	2,170,283	2,306,419
Warrants	1,830,464	33,086,615	17,929,512

(1)Includes vested common shares in the Company’s deferred compensation plan and vested deferred restricted stock units, both of which will deliver shares to participants at a later date. Although shares have not been delivered on these awards, all conditions for issuance and delivery have been met. Pursuant to FASB ASC 260-10-45-13, such shares are to be included in the denominator in calculating basic earnings per share.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Common Stock Issuance—During 2012 and 2013, the Company issued common stock to generate capital, fund its 401K and deferred compensation plans (Note 18), fund property acquisitions (Note 3) and to retire outstanding warrants (Note 12). Equity issuances intended to raise capital are discussed below. Proceeds from these transactions were used for debt repayment and for other general corporate purposes.

During 2012, the Company issued common stock to White Deer in three separate transactions as disclosed in the table below.

	February 2012	August 2012	December 2012
Gross proceeds (in thousands)	$ 7,500	$ 6,000	$ 6,500
Common shares sold	2,180,233	3,076,923	4,577,464

The Company has an effective $100 million universal shelf registration statement under which it has been selling common shares pursuant to an at-the-market issuance sales agreement as disclosed in the table below.

	Year Ended December 31,	
	2012	2013
Gross proceeds (in thousands)	$ 724	$ 4,076
Common shares sold	446,098	2,592,313

Note 14—Commitments and Contingencies

Litigation—The Company is subject, from time to time, to certain legal proceedings and claims in the ordinary course of conducting its business. It records a liability related to its legal proceedings and claims when it has been determined that it is probable that it will be obligated to pay and the related amount can be reasonably estimated. The Company currently believes that there are no pending legal proceedings in which it is currently involved which have a reasonable possibility of materially affecting its financial position, results of operations or cash flows in an adverse manner.

The Company had been sued in royalty owner lawsuits filed in Oklahoma and Kansas. In Oklahoma, suits by a group of individual royalty owners and by a putative class representing all remaining royalty owners were filed in the District Court of Nowata County, Oklahoma. Generally, the lawsuits alleged that the Company wrongfully deducted post-production costs from the plaintiffs' royalties and engaged in self-dealing agreements resulting in a less than market price for the gas production. The Company denied the allegations. Settlements were reached in each of the cases, and upon final approval from the Court, the Company paid $5.6 million in settlement of the Oklahoma suits in July 2011.

The Kansas lawsuit was a putative class action filed in the United States District Court for the District of Kansas, brought on behalf of all the Company's royalty owners in that state. Plaintiffs generally alleged that the Company failed to properly make royalty payments by, among other things, charging post-production costs to royalty owners in violation of the underlying lease contracts, paying royalties based on sale point volumes rather than wellhead volumes, allocating expenses in excess of the actual and reasonable post-production costs incurred, allocating production costs and marketing costs to royalty owners, and making royalty payments after the statutorily prescribed time for doing so without paying interest thereon. We denied plaintiffs' claims. The parties reached a settlement and on December 30, 2011, the Court entered an order certifying a class for settlement purposes consisting of all current and former PostRock royalty and overriding royalty owners, approving the parties' settlement and dismissing the action. The settlement included a payment of $3.0 million that was made in January 2012, and a payment of $4.5 million which was made in December 2012, for a total of $7.5 million.

In connection with their criminal convictions, in November 2010, Jerry Cash and David Grose were ordered to pay the Company restitution in the sums of $5 million and $1 million, respectively. The Company intends to continue to pursue recovery of the restitution obligations.

Additionally, see Note 8 – Equity Investment for discussion on litigation with CEP. Litigation reserve expense was $11.6 million for the year ended December 31, 2011, while no litigation reserve expense was recorded for the years ended December 31, 2012 and 2013, respectively.

Environmental Matters—At December 31, 2012 and 2013, there were no known environmental or regulatory matters related to our operations which are reasonably expected to result in a material liability to us. Like other oil and gas producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental regulations governing air emissions,

wastewater discharges, and solid and hazardous waste management activities. Therefore it is difficult to reasonably quantify future environmental related expenditures.

Operating Lease Commitments—The Company has lease agreements to obtain natural gas compressors as and when required. Terms of the leases on the gas compressors call for a minimum obligation of one year and are month to month thereafter. In addition, the Company also has operating leases for office space, warehouse facilities, and office equipment expiring in various years through 2018.

Future minimum rental payments under all non-cancelable operating leases at December 31, 2013, were as follows:

Year ending December 31,	(in thousands)
2014	$ 3,558
2015	2,468
2016	847
2017	373
2018	10
Thereafter	—
Total minimum lease obligations	$ 7,256

Total rental expense under cancelable and non-cancelable operating leases was $13.6 million, $12.4 million and $10.8 million for the years ended December 31, 2011, 2012 and 2013, respectively.

Note 15—Impairment of Oil and Gas Properties

At the end of each quarterly period, the unamortized cost of oil and natural gas properties, net of related deferred income taxes, is limited to the full cost ceiling, computed as the sum of the estimated future net revenues from proved reserves using twelve-month average prices discounted at 10%, and adjusted for related income tax effects (ceiling test). Under full cost accounting rules, any ceiling test write-down of oil and natural gas properties may not be reversed in subsequent periods. Since the Company does not designate its derivative financial instruments as hedges, it is not allowed to use the impacts of the derivative financial instruments in its ceiling test computation. As a result, decreases in commodity prices which contribute to ceiling test write-downs may be offset by mark-to-market gains which are not reflected in the Company's ceiling test results.

The base for the Company's spot prices for natural gas is Henry Hub and for oil is Cushing, Oklahoma. At the end of the third and fourth quarters of 2012, the ceiling test computation resulted in the carrying costs of the Company's unamortized proved oil and natural gas properties, net of deferred taxes, exceeding the present value of future net revenues. As a result of this difference, the Company recorded ceiling test impairments of its oil and gas properties of $5.9 million for the year ended December 31, 2012. There were no ceiling test impairments for the years ended December 31, 2011 and 2013. The Company may face further ceiling test write-downs in future periods, depending on the level of commodity prices, drilling results and well performance.

The calculation of the ceiling test is based upon estimates of proved reserves. There are numerous uncertainties inherent in estimating quantities of proved reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing, production and changes in economics related to the properties subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

Note 16—Discontinued Operations

The Company previously owned an interstate natural gas pipeline in its PostRock KPC Pipeline, LLC ("KPC") subsidiary. On September 28, 2012, the Company, PostRock Energy Services Corporation, a wholly owned subsidiary of the Company ("Seller"), and KPC entered into and simultaneously closed a Purchase Agreement (the "Purchase Agreement") with MV pursuant to which the Seller sold all the equity of KPC to MV for a gross purchase price of $53.5 million. After an adjustment for working capital as set forth in the Purchase Agreement, the Company received $53.4 million in proceeds at closing. MV also agreed to make additional payments of $1.0 million for each of the next four years if qualified EBITDA (as defined in the Purchase Agreement) of KPC for that year exceeds a target amount. Determination of qualified EBITDA for the first year is due from MV no later than May 30, 2014. KPC owns a 1,120 mile interstate natural gas pipeline that transports natural gas from northern Oklahoma and western Kansas to Wichita and Kansas City, which formerly comprised the Company's pipeline segment.

The carrying value of KPC's net assets sold was $57.0 million which resulted in a loss on sale of $5.4 million. The loss on sale included $1.9 million in closing-related costs comprised of $1.0 million in legal, professional, and investment banking fees, $505,000 of severance and $350,000 in site cleanup costs. The operating results of KPC are classified as discontinued operations and are presented in a separate line in the consolidated statement of operations for all periods presented. Prior to the classification as a discontinued operation, the Company had reported this business as a separate segment under the heading "Pipeline."

The following table discloses the results of discontinued operations related to KPC:

	Year Ended December 31, 2011	Year Ended December 31, 2012
	(in thousands)	
Interstate pipeline revenue	$ 11,183	$ 8,934
Pipeline expense	(5,219)	(2,825)
Depreciation and amortization	(3,574)	(2,537)
Gain (loss) on disposal of assets (1)	3	(5,437)
General and administrative expenses	(1,194)	(945)
Interest expense	(556)	(45)
Income from discontinued operations before income taxes	643	(2,855)
Income taxes	—	—
Total income (loss) from discontinued operations	$ 643	$ (2,855)

(1)Includes a loss of $5.4 million from the disposal of KPC.

Note 17—Supplemental Cash Flow Information

The following discloses certain cash and noncash transactions for the periods indicated:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
Cash paid for interest	$ 8,623	$ 7,292	$ 2,780
Cash paid for income taxes	—	—	100
Non-cash investing activity			
Common stock issued for purchase of equity investment	4,100	—	—
Common stock issued for purchase of oil and gas properties	—	—	6,728
Common stock issued to fund 401K and deferred compensation plans	—	—	931
Common stock issued to repurchase and retire outstanding warrants	—	—	1,528
Warrants issued for purchase of equity investment	518	—	—
Equity securities received on the sale of oil and gas properties	5,875	—	—
Property additions financed through accounts payable and accrued liabilities	830	239	1,010
Additions to property and equipment by recognizing asset retirement obligations	4,067	159	1,099
Non-cash financing activity			
Reduction of debt through conveyance of financial securities received from sale of oil and gas properties	5,729	—	—
Reduction of debt through issuance of common stock	843	—	—
Issuance of preferred stock and warrants in lieu of cash dividends	7,779	9,083	11,464
Accretion of discount on redeemable preferred stock reflected in interest expense	—	—	80
Accretion of discount on redeemable preferred stock	1,580	2,238	3,283

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 18—Profit Sharing and Deferred Compensation Plan

401K plan — Substantially all of the Company's employees are eligible to participate in a profit sharing plan under Section 401(k) of the Internal Revenue Code (the "401K plan"). In 2013, the Company contributed three percent of employees' annual compensation regardless whether contributions were made by the employee. The Company would also match 100% of employee contributions in excess of three percent up to a total of six percent of annual compensation. Employees vest 33% in Company contributions in their first year of service, 67% in their second year of service and 100% in their third year of service. Prior to 2013, employer matching contributions to the 401K plan were made in cash. Beginning in 2013, employer matching contributions to the 401K plan may be made in Company common stock. In general, the Company issues common stock to fund its matching contributions although, from time to time, purchases of common stock on the open market by the 401K plan trust may occur if funds are available as a result of forfeitures. During the year ended December 31, 2013, 404,805 shares of common stock were contributed to the 401K plan, of which 325,005 shares were issued by the Company, and 79,800 shares were purchased by the 401K plan trust on the open market.

The following table presents the expense incurred by the Company related to the 401K plan which is reflected in the consolidated statements of operations as a component of general and administrative expense:

	Year Ended December 31,		
	2011	2012	2013
	(in thousands)		
401(k) profit sharing plan cost	$ 492	$ 235	$ 662

Deferred compensation plan — Effective January 1, 2013, the Company established a deferred compensation plan that permits selected employees and members of its board to defer part or all of their eligible compensation. The following table presents the number of shares and the related fair values of common stock contributed by the Company to the deferred compensation plan in 2013. The fair value of common stock is based on the market price of the stock on the preceding day that the stock is transferred and thus deemed to be a Level 1 measurement under the fair value hierarchy. Contributions were not made in the prior year as the plan was not in effect during that time.

	Year Ended December 31, 2013 ($ in thousands)
Shares of common stock contributed	324,522
Fair value of common stock contributed	$ 473

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Note 19—Supplemental Financial Information—Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2012 and 2013 are as follows:

	Quarters Ended March 31,	June 30,	September 30,	December 31,
	(in thousands, except per share data)			
2012				
Total revenues	$ 14,321	$ 11,124	$ 13,697	$ 15,853
Operating income (loss) (1)	(7,501)	(10,352)	(11,409)	(6,649)
Net income (loss)	7,347	(18,508)	(25,174)	(11,237)
Net income (loss) per common share				
Basic	$ 0.43	$ (1.71)	$ (1.94)	$ (0.89)
Diluted	$ 0.37	$ (1.71)	$ (1.94)	$ (0.89)

	Quarters Ended March 31,	June 30,	September 30,	December 31,
	(in thousands, except per share data)			
2013				
Total revenues	$ 16,053	$ 19,594	$ 18,614	$ 18,039
Operating income (loss) (1)	(3,727)	(2,019)	(1,679)	(3,873)
Net income (loss)	(7,894)	6,880	(645)	(7,377)
Net income (loss) per common share				
Basic	$ (0.50)	$ 0.13	$ (0.18)	$ (0.38)
Diluted	$ (0.50)	$ 0.13	$ (0.18)	$ (0.38)

(1)Total revenue less total costs and expenses.

Note 20—Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The supplementary oil and gas data that follows is presented in accordance with FASB ASC 932 Extractive Activities—Oil and Gas ("FASB ASC 932"), and includes (1) capitalized costs, costs incurred and results of operations related to oil and gas producing activities, (2) net proved oil and gas reserves, and (3) a standardized measure of discounted future net cash flows relating to proved oil and gas reserves.

Equity investment—At December 31, 2013, the Company owns 21.3% voting interest in CEP, a publicly traded oil and gas exploration and production company. The Company's equity interest in CEP was 26.4% and 26.5% at December 31, 2011 and 2012, respectively. CEP utilizes the successful efforts method of accounting for its oil and gas activities. Where applicable, the disclosures required under FASB ASC 932 are made below based on the Company's proportionate share of CEP's oil and gas activities according to the percentages described above. Information utilized to prepare disclosures on the Company's proportionate share of CEP is based on publicly available data. The Company has updated previously filed amounts for December 31, 2012 related to CEP as discontinued operations have now been presented in their current public filing. Since December 31, 2011 amounts were not publicly available these amounts do not reflect the changes from discontinued operations.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Net Capitalized Costs

Aggregate capitalized costs related to oil and gas producing activities of the Company at December 31, 2012 and 2013, are summarized as follows:

	2012	2013
	(in thousands)	
Oil and gas properties and related leasehold costs		
Proved	$ 353,093	$ 405,895
Unproved	31	4,862
	353,124	410,757
Accumulated depreciation, depletion and amortization	(245,593)	(268,846)
Net capitalized costs	$ 107,531	$ 141,911

Unproved properties not subject to amortization consisted mainly of leaseholds acquired through acquisitions. The Company will continue to evaluate its unproved properties; however, the timing of the ultimate evaluation and disposition of the properties has not been determined.

Aggregate capitalized costs related to oil and gas producing activities of the Company's proportionate investment in CEP at December 31, 2012 and 2013, are summarized as follows:

	2012	2013
	(in thousands)	
Oil and gas properties and related equipment (successful efforts		

method)				
Proved	$	156,851	$	135,642
Unproved		366		338
Materials, supplies and land		402		385
		157,619		136,365
Accumulated depreciation, depletion and amortization		(125,787)		(105,481)
Net capitalized costs	$	31,832	$	30,884

Costs Incurred

Costs incurred for oil and gas property acquisition, exploration and development activities that have been capitalized for the years ended December 31, 2011, 2012, and 2013 are summarized as follows:

	Consolidated Entities			CEP (1)		
	2011	2012	2013	2011	2012	2013
	(in thousands)					
Proved property acquisition costs (2)	$ 223	$ 151	$ 8,023	$ (74)	$ 20	$ 4,262
Unproved property acquisition costs	630	52	8,567	167	47	45
Exploration costs	—	—	—	—	—	—
Development Costs	23,825	12,506	40,004	2,895	4,064	3,343
	$ 24,678	$ 12,709	$ 56,594	$ 2,988	$ 4,131	$ 7,650

____

(1)Based on the Company's pro-rata interest in CEP (disclosed above) assuming that the Company's investment was made at the beginning of the period.

(2)The amount is negative for CEP in 2011 as it represents a post-closing receipt from an acquisition made by CEP in December 2010.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Results of Operations

The revenues and expenses associated directly with the Company’s oil and natural gas producing activities are reflected in the consolidated statement of operations. All of our ongoing operations are oil and natural gas producing activities located in the United States.

The table below presents the pro-rata results of oil and gas producing activities of the Company’s investment in CEP for the years ended December 31, 2011, 2012, and 2013 assuming that the Company’s investment was made at the beginning of the period presented.

	2011	2012	2013
	(in thousands)		
Revenues	$ 27,778	$ 12,330	$ 9,388
Lease operating expense	7,379	5,144	4,017
Cost of sales and production taxes	1,343	780	864
Exploration costs	35	—	—
Impairment of oil and gas properties	775	29	502
Depreciation, depletion and amortization	5,845	3,109	4,041

Oil and Gas Reserve Quantities

The following reserve schedule was developed by the Company’s reserve engineers and sets forth the changes in estimated quantities for its proved reserves, all of which are located in the United States. Cawley, Gillespie & Associates, Inc., independent reserve engineering firm, was retained to perform the annual year-end independent evaluation of the Company’s proved reserves.

Users of this information should be aware that the process of estimating quantities of “proved,” “proved developed” and “proved undeveloped” oil and gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history, and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions (upwards or downward) to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The table below presents changes in proved developed and undeveloped reserves of our consolidated entities.

	Gas - Mcf	Oil - Bbls
Proved reserves		
Balance, December 31, 2010	130,462,031	744,266
Purchase of reserves in place	—	—
Extensions, discoveries, and other additions	1,752,746	54,761
Sale of reserves	(754,479)	—
Revisions of previous estimates	5,068,946	352,981
Production	(18,309,056)	(78,087)
Balance, December 31, 2011	118,220,188	1,073,921
Purchase of reserves in place	—	—
Extensions, discoveries, and other additions	1,867,365	617,854
Sale of reserves	—	—
Revisions of previous estimates	(34,037,402)	1,095,656
Production	(16,388,878)	(95,863)
Balance, December 31, 2012	69,661,273	2,691,568
Purchase of reserves in place	98,822	554,892
Extensions, discoveries, and other additions	1,122,511	1,911,959
Sale of reserves	—	—
Revisions of previous estimates	30,246,006	(585,342)
Production	(14,521,385)	(192,474)
Balance, December 31, 2013	86,607,227	4,380,603
Proved developed reserves		
Balance, December 31, 2011	117,406,577	1,040,309
Balance, December 31, 2012	69,661,273	1,804,057
Balance, December 31, 2013	85,006,592	2,705,664

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The table below presents the Company's pro-rata share of changes in reserves and the amounts of proved developed reserves of CEP assuming that the Company's investment was made as of January 1, 2011.

	Mcfe
Proved reserves	
Balance, January 1, 2011	44,618,000
Purchase of reserves in place	—
Extensions, discoveries, and other additions	455,000
Sale of reserves	—
Revisions of previous estimates	11,216,000
Production	(3,138,000)
Balance, December 31, 2011	53,151,000
Purchase of reserves in place	—
Extensions, discoveries, and other additions	543,000
Sale of reserves	(68,000)
Revisions of previous estimates	(25,551,000)
Production	(3,435,000)
Balance, December 31, 2012	24,640,000
Decrease in pro rata ownership	(4,835,000)
Purchase of reserves in place	1,523,000
Extensions, discoveries, and other additions	1,028,000
Sale of reserves	(10,519,000)
Revisions of previous estimates	9,527,000
Production	(1,927,000)
Balance, December 31, 2013	19,437,000
Proved developed reserves	
Balance, December 31, 2011	40,295,000
Balance, December 31, 2012	23,850,000
Balance, December 31, 2013	16,748,000

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

Standardized Measure of Discounted Future Net Cash Flows

The following information is based on the Company's best estimate of the required data for the Standardized Measure of Discounted Future Net Cash Flows at December 31, 2011, 2012 and 2013 in accordance with FASB ASC 932 which requires the use of a 10% discount rate. Future income taxes are based on year-end statutory rates. This information is not the fair market value, nor does it represent the expected present value of future cash flows of Company's proved oil and gas reserves.

	Consolidated Entities			CEP (1)		
	2011	2012	2013	2011	2012	2013
	(in thousands)					
Future cash inflows	$ 592,796	$ 438,356	$ 720,924	$ 241,173	$ 95,619	$ 107,103
Future production costs	312,410	218,707	315,079	132,081	51,462	48,418
Future development costs	10,524	31,051	49,590	25,705	2,948	8,668
Future income tax expense	—	—	30,149	—	—	—
Future net cash flows	269,862	188,598	326,106	83,387	41,209	50,017
10% annual discount for estimated timing of cash flows	94,342	86,516	156,977	40,964	17,446	19,406
Standardized measure of discounted future net cash flows related to proved reserves	$ 175,520	$ 102,082	$ 169,129	$ 42,423	$ 23,763	$ 30,611
Standardized measure from continuing operations	$ 175,520	$ 102,082	$ 169,129	$ 42,423	$ 16,021	$ 30,611
Standardized measure from discontinued operations	—	—	—	—	7,742	—
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 175,520	$ 102,082	$ 169,129	$ 42,423	$ 23,763	$ 30,611

(1)Represents the Company's pro-rata share of its investment in CEP.

Future cash inflows are computed by applying a first-day-of-month, twelve-month average price, adjusted for location and quality differentials on a property-by-property basis, to year-end quantities of proved reserves, except in those instances where fixed and determinable price changes are provided by contractual arrangements at year-end. The discounted future cash flow estimates do not include the effects of our derivative instruments. See the following table for average oil and gas prices as of the periods indicated.

	2011	2012	2013
Crude oil price per Bbl	$ 96.19	$ 95.05	$ 96.94
Natural gas price per MMBtu	$ 4.12	$ 2.76	$ 3.67

Table of Contents

POSTROCK ENERGY CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS—(Continued)

The principal changes in the standardized measure of discounted future net cash flows relating to proven oil and gas properties were as follows:

	Consolidated Entities			CEP (1)		
	2011	2012	2013	2011	2012	2013
	(in thousands)					
Present value, beginning of period	$ 159,261	$ 175,520	$ 102,082	$ 34,765	$ 42,423	$ 23,763
Net changes in prices and production costs	11,876	18,071	37,826	38	(5,095)	10,741
Decrease in pro rata ownership	—	—	—	—	—	(4,664)
Net changes in future development costs	(1,154)	(18,008)	(30,462)	—	—	—
Previously estimated development costs incurred	18,192	12,743	40,196	1,892	4,987	1,196
Sales of oil and gas produced, net	(32,751)	(10,338)	(29,604)	(7,810)	(10,520)	(4,525)
Extensions and discoveries	3,045	7,724	23,514	2,157	3,336	6,069
Purchases of reserves in-place	—	—	6,401	—	—	—
Sales of reserves in-place	(1,104)	—	—	—	(391)	(489)
Revisions of previous quantity estimates	10,513	(38,064)	49,926	11,243	(22,034)	4,570
Net change in income taxes	12,037	—	(7,769)	—	—	—
Accretion of discount	16,448	16,730	8,975	3,477	4,258	1,910
Timing differences and other (2)	(20,843)	(62,296)	(31,956)	(3,339)	6,799	(7,960)
Present value, end of period	$ 175,520	$ 102,082	$ 169,129	$ 42,423	$ 23,763	$ 30,611
Standardized measure from continuing operations	$ 175,520	$ 102,082	$ 169,129	$ 42,423	$ 16,021	$ 30,611
Standardized measure from discontinued operations	—	—	—	—	7,742	—
Standardized measure of discounted future net cash flows related to proved gas reserves	$ 175,520	$ 102,082	$ 169,129	$ 42,423	$ 23,763	$ 30,611

(1)Represents the Company's pro-rata share of its investment in CEP assuming that the Company's investment was made at the beginning of each period presented.

(2)The change in timing differences and other are related to revisions in the Company's estimated time of production and development and the impact of changes in the relative proportion of oil versus natural gas in the Company's total reserves.

During 2013, the Company focused its development activities on oil related projects. As a result, the proportion of oil reserves to total reserves increased from 5% at December 31, 2011, to 19% at December 31, 2012 and 23% as of December 31, 2013. Since the Company calculates the price variance on an energy equivalent basis, the change in the Company's reserve mix coupled with the 26:1 ratio of oil price to natural gas price used in the calculation, resulted in a positive net price variance. The positive price variance is reflected under "net changes in prices and production costs" in the table above. As a positive net price variance is disclosed, existing natural gas reserves, which comprised 77% of total reserves at December 31, 2013, decreased in value due to a decrease in the average natural gas price. This decline in value of natural gas reserves is included in "timing differences and other" in the table above.

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized this 27th day of March, 2014.

POSTROCK ENERGY CORPORATION

/s/ TERRY W. CARTER
Terry W. Carter
Chief Executive Officer and President

POWER OF ATTORNEY

By signing this Annual Report on Form 10-K below, I hereby appoint Terry W. Carter as my attorney-in-fact to sign any and all amendments to this Annual Report on Form 10-K on my behalf, and to file this Annual Report on Form 10-K (including all exhibits and other documents related to the Annual Report on Form 10-K) with the Securities and Exchange Commission. I authorize each of my attorneys-in-fact to (1) appoint a substitute attorney-in-fact for himself and (2) perform any actions that he believes are necessary or appropriate to carry out the intention and purpose of this Power of Attorney. I ratify and confirm all lawful actions taken directly or indirectly by my attorneys-in-fact and by any properly appointed substitute attorneys-in-fact.

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

Name	Capacity	Date
/S/ TERRY W. CARTER Terry W. Carter	Chief Executive Officer and President and Director (Principal Executive and Financial Officer)	March 27, 2014
/S/ Casey E. Bigelow	Chief Accounting Officer	

Casey E. Bigelow		March 27, 2014
/S/ DUKE R. LIGON Duke R. Ligon	Chairman of the Board	March 27, 2014
/S/ NATHAN M. AVERY Nathan M. Avery	Director	March 27, 2014
/S/ WILLIAM H. DAMON III William H. Damon III	Director	March 27, 2014
/S/ THOMAS J. EDELMAN Thomas J. Edelman	Director	March 27, 2014
/S/ J. PHILIP MCCORMICK J. Philip McCormick	Director	March 27, 2014
/S/ MARK A. STANSBERRY Mark A. Stansberry	Director	March 27, 2014

Table of Contents

INDEX TO EXHIBITS

Exhibit No.	Description
2.1	Purchase Agreement, dated September 28, 2012, by and among PostRock, PostRock Energy Services Corporation, PostRock KPC Pipeline, LLC and MV Pipelines, LLC (incorporated herein by reference to Exhibit 2.1 to PostRock's Current Report on Form 8-K filed on October 3, 2012).
2.2	Purchase and Sale Agreement, dated as of December 24, 2010, by and among Quest Eastern Resource LLC, PostRock MidContinent Production, LLC, Magnum Hunter Resources Corporation and Triad Hunter, LLC (portions of this exhibit have been omitted and filed separately with the Securities and Exchange Commission pursuant to a confidential treatment request under Rule 24b-2 of the Securities Exchange Act of 1934, as amended) (incorporated herein by reference to Exhibit 2.1 to PostRock's Current Report on Form 8-K filed on January 21, 2011).
2.3	Purchase Agreement, dated August 8, 2011 ("CEG Purchase Agreement"), by and among PostRock, Constellation Energy Commodities Group, Inc. and Constellation Energy Partners Holdings, LLC (incorporated herein by reference to Exhibit 2.1 to PostRock's Current Report on Form 8-K filed on August 12, 2011).
2.4	Purchase Agreement, dated December 19, 2011, by and among PostRock, Constellation Energy Partners Management LLC, Constellation Energy Commodities Group, Inc. and Constellation Energy Partners Holdings, LLC (incorporated herein by reference to Exhibit 2.1 to PostRock's Current Report on Form 8-K filed on December 23, 2011).
2.5*	Purchase and Sale Agreement, dated October 14, 2013 (the "West Star PSA"), by and among PostRock, PostRock MidContintent Production, LLC, West Star Operating Company, West Star Exploration and Production Company and Shalco Energy (Delaware), LLC.
3.1	Restated Certificate of Incorporation of PostRock (incorporated herein by reference to Exhibit 3.1 to PostRock's Current Report on Form 8-K filed on March 10, 2010).
3.2	Certificate of Amendment to Restated Certificate of Incorporation of PostRock (incorporated herein by reference to Exhibit 3.2 to PostRock's Registration Statement on Form S-8 filed on May 17, 2012, Registration No. 333-181480).
3.3	Bylaws of PostRock (incorporated herein by reference to Exhibit 3.2 to PostRock's Current Report on Form 8-K filed on March 10, 2010).
4.1	Specimen of certificate for shares of Common Stock of PostRock (incorporated herein by reference to Exhibit 4.1 to Amendment No. 1 to PostRock's Registration Statement on Form S-4 filed on December 17, 2009, Registration No. 333-162366).
4.2	Second Amended and Restated Certificate of Designations for the Series A Cumulative Redeemable Preferred Stock (incorporated herein by reference to Exhibit 4.1 to PostRock's Current Report on Form 8-K filed on December 21, 2012).
4.4	Certificate of Designations for the Series B Voting Preferred Stock (incorporated herein by reference to Exhibit 4.2 to PostRock's Current Report on Form 8-K filed on September 23, 2010).
4.5	

	Form of Warrant with respect to the 2010 White Deer SPA (as defined below) (incorporated herein by reference to Exhibit 4.3 to PostRock's Current Report on Form 8-K filed on September 3, 2010).
4.6	Form of Warrant with respect to the CEG Purchase Agreement (incorporated herein by reference to Exhibit 4.1 to PostRock's Current Report on Form 8-K filed on August 12, 2011).
4.7	Form of Warrant with respect to the August White Deer SPA (as defined below) (incorporated herein by reference to Exhibit 4.2 to PostRock's Current Report on Form 8-K filed on August 7, 2012).
4.8	Form of Warrant with respect to the December White Deer SPA (as defined below) (incorporated herein by reference to Exhibit 4.2 to PostRock's Current Report on Form 8-K filed on December 21, 2012).
4.9*	Registration Rights Agreement with respect to the West Star PSA, dated November 1, 2013, by and among PostRock, West Star Operating Company, West Star Exploration and Production Company and Shalco Energy (Delaware), LLC.
10.1	Securities Purchase Agreement dated September 2, 2010 (the "2010 White Deer SPA") among PostRock, White Deer Energy L.P., White Deer Energy TE L.P., and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to PostRock's Current Report on Form 8-K filed on September 3, 2010).
10.2	Stock Purchase Agreement, dated February 9, 2012, among PostRock, White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to PostRock's Current Report on Form 8-K filed on February 15, 2012).

Table of Contents

10.3 Securities Purchase Agreement, dated August 1, 2012 (the "August White Deer SPA"), among PostRock, White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on August 7, 2012).
10.4 Securities Purchase Agreement, dated December 17, 2012 (the "December White Deer SPA"), among PostRock, White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to PostRock's Current Report on Form 8-K filed on December 21, 2012).
10.5 First Amended and Restated Registration and Investor Rights Agreement, dated August 8, 2011 (the "RRA"), by and among PostRock, Constellation Energy Commodities Group, Inc., White Deer Energy L.P., White Deer Energy TE, L.P. and White Deer Energy FI L.P. (incorporated herein by reference to Exhibit 10.1 to PostRock's Current Report on Form 8-K filed on August 12, 2011).
10.6 Amendment No. 1, dated as of February 9, 2012, among PostRock, White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P., to the RRA (incorporated herein by reference to Exhibit 10.2 to PostRock's Current Report on Form 8-K filed on February 15, 2012).
10.7 Amendment No. 2, dated as of August 1, 2012, among PostRock, White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P., to the RRA (incorporated herein by reference to Exhibit 10.2 to PostRock's Current Report on Form 8-K filed on August 7, 2012).
10.8 Amendment No. 3, dated as of December 20, 2012, among PostRock, White Deer Energy L.P., White Deer Energy TE L.P. and White Deer Energy FI L.P., to the RRA (incorporated herein by reference to Exhibit 10.2 to PostRock's Current Report on Form 8-K filed on December 21, 2012).
10.9 Form of Indemnification Agreement for Officers and Directors (incorporated herein by reference to Exhibit 10.2 to PostRock's Current Report on Form 8-K filed on September 23, 2010).
10.10† PostRock 2010 Long-Term Incentive Plan (incorporated herein by reference to Annex B to the joint proxy statement/prospectus that is a part of PostRock's Registration Statement on Form S-4/A filed on February 2, 2010).
10.11† Amendment No. 1 to PostRock 2010 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.33 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2011, filed on March 8, 2012).
10.12† Second Amendment to PostRock 2010 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 4.7 to PostRock's Registration Statement on Form S-8 filed on May 17, 2012, Registration No. 333-181480).
10.13† Third Amendment to PostRock 2010 Long-Term Incentive Plan (incorporated herein by reference to Exhibit 10.1 to PostRock's Quarterly Report on Form 10-Q for the quarter ended June 30, 2013, filed on August 14, 2013).
10.14† Nonqualified Stock Option Agreement, dated August 15, 2007, between QRCP and William Damon III (incorporated herein by reference to Exhibit 10.75 to PostRock's Registration Statement on Form S-4/A filed on December 17, 2009, Registration No. 333-162366).
10.15† PostRock 2010 Long-Term Incentive Plan Form of 2011 Restricted Share Award Agreement (incorporated herein by reference to Exhibit 10.1 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed on May 11, 2011).
10.16† PostRock 2010 Long-Term Incentive Plan Form of 2011 Restricted Share Award Agreement (multi-year vesting, change in control) (incorporated herein by reference to Exhibit 10.15 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
10.17† PostRock 2010 Long-Term Incentive Plan Form of Bonus Share Award Agreement (incorporated herein by reference to Exhibit 10.1 to PostRock's Current Report on Form 8-K filed on August 10, 2010).
10.18† PostRock 2010 Long-Term Incentive Plan Form of Restricted Share Award Agreement (change in control, one-year vesting) (incorporated herein by reference to Exhibit 10.17 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
10.19†

PostRock 2010 Long-Term Incentive Plan Form of Restricted Share Award Agreement (change in control, two-year vesting) (incorporated herein by reference to Exhibit 10.18 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).

10.20† PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (immediate vesting) (incorporated herein by reference to Exhibit 10.19 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).

10.21† PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (one-year vesting) (incorporated herein by reference to Exhibit 10.20 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).

10.22† PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (multi-year vesting) (incorporated herein by reference to Exhibit 10.2 to PostRock's Current Report on Form 8-K filed on August 10, 2010).

10.23† PostRock Executive Nonqualified Excess Plan Adoption Agreement (incorporated herein by reference to Exhibit 10.1 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, filed on May 9, 2013).

10.24† PostRock Executive Nonqualified Excess Plan (incorporated herein by reference to Exhibit 10.2 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2013, filed on May 9, 2013).

10.25† PostRock 2010 Long-Term Incentive Plan Form of Stock Option Award Agreement (multi-year vesting, change of control) (incorporated herein by reference to Exhibit 10.22 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).

10.26† PostRock 2010 Long-Term Incentive Plan Form of Restricted Share Award Agreement (multi-year vesting) (incorporated herein by reference to Exhibit 10.3 to PostRock's Current Report on Form 8-K filed on August 10, 2010).

10.27† PostRock 2010 Long-Term Incentive Plan Form of Restricted Share Unit Award Agreement (multi-year vesting) (incorporated herein by reference to Exhibit 10.4 to PostRock's Current Report on Form 8-K filed on August 10, 2010).

10.28† PostRock Form of Director Restricted Share Unit Award Agreement (Immediate Vesting) (incorporated herein by reference to Exhibit 10.5 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed on May 11, 2012).

10.29† PostRock Form of Director Restricted Share Unit Award Agreement (One Year Vesting, Five Year Settlement) (incorporated herein by reference to Exhibit 10.6 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed on May 11, 2012).

10.30† PostRock Energy Services Corporation 401(k) Profit Sharing Plan (incorporated herein by reference to Exhibit 4.5 to PostRock's Registration Statement on Form S-8 filed on December 28, 2012, Registration No. 333-185722).

10.31† Change in Control Severance Plan for Chief Executive Officer (incorporated herein by reference to Exhibit 10.3 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed on May 11, 2012).

10.32† Change in Control Severance Plan for Executive Officers Other than CEO and President (incorporated herein by reference to Exhibit 10.4 to PostRock's Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, filed on May 11, 2012).

10.33 At-The-Market Issuance Sales Agreement dated August 23, 2011 between PostRock and McNicoll, Lewis & Vlak LLC (incorporated herein by reference to Exhibit 10.1 to PostRock's Current Report on Form 8-K filed on August 24, 2011).

10.34 Amendment No. 1, dated August 23, 2013, to At-The-Market Issuance Sales Agreement, dated August 23, 2011, between PostRock Energy Corporation and MLV & Co. LLC (formerly McNicoll, Lewis & Vlak LLC), as agent (incorporated herein by reference to Exhibit 1.1 to PostRock's Current Report on Form 8-K filed on August 23, 2013).

10.35 Master Assignment and Assumption, dated December 20, 2012, by and among the assignor lenders party thereto and the assignee lenders party thereto (incorporated herein by reference to Exhibit 10.31 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).

10.36 Third Amended and Restated Credit Agreement, dated December 20, 2012, among PostRock Energy Services Corporation and PostRock MidContinent Production, LLC, as Borrowers, Citibank, N.A., as Administrative

	Agent and Collateral Agent, and the lenders party thereto (incorporated herein by reference to Exhibit 10.32 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
10.37	Amended and Restated Intercreditor and Collateral Agency Agreement, dated September 21, 2010, among Royal Bank of Canada, BP Corporation North America Inc., and PostRock Energy Services Corporation and PostRock MidContinent Production, LLC, as Borrowers (incorporated herein by reference to Exhibit 10.4 to PostRock's Current Report on Form 8-K filed on September 23, 2010).

10.38	Second Amendment to Amended and Restated Intercreditor and Collateral Agency Agreement, dated December 20, 2012, among Royal Bank of Canada, Citibank, N.A., BP Energy Company, PostRock Energy Services Corporation and PostRock MidContinent Production, LLC, as Borrowers, PostRock, PostRock Holdco, LLC, PostRock Eastern Production, LLC and STP Newco, Inc., as Obligors (incorporated herein by reference to Exhibit 10.34 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
10.39	Second Amended and Restated Guaranty, dated December 20, 2012, executed by PostRock in favor of Citibank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 10.35 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
10.40	Amended and Restated Guaranty (Subsidiary), dated December 20, 2012, executed by PostRock Eastern Production, LLC, PostRock Holdco, LLC and STP Newco, Inc. in favor of Citibank, N.A., as Administrative Agent (incorporated herein by reference to Exhibit 10.36 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
10.41	Second Amended and Restated Pledge and Security Agreement, dated December 20, 2012, among PostRock Energy Services Corporation, PostRock MidContinent Production, LLC, PostRock, PostRock Eastern Production, LLC, STP Newco, Inc. and PostRock Holdco, LLC in favor of Citibank, N.A., as Collateral Agent (incorporated herein by reference to Exhibit 10.37 to PostRock's Annual Report on Form 10-K for the year ended December 31, 2012, filed on March 12, 2013).
	Warrant Exchange Agreement, dated November 27, 2013, by and among PostRock, White Deer Energy L.P., White Deer Energy TW L.P. and White Deer Energy FI L.P.
10.42*	
21.1*	List of Subsidiaries.
23.1*	Consent of Cawley, Gillespie & Associates, Inc.
23.2*	Consent of UHY LLP.
31.1*	Certification by principal executive officer who also serves as principal financial officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1*	Certification by principal executive officer who also serves as principal financial officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Cawley, Gillespie & Associates, Inc.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema Document.
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB*	XBRL Taxonomy Extension Labels Linkbase Document.
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF*	Taxonomy Extension Definition Linkbase Document

*Filed herewith.

†Management contracts and compensatory plans and arrangements.

PLEASE NOTE: Pursuant to the rules and regulations of the Securities and Exchange Commission, we have filed or incorporated by reference the agreements referenced above as exhibits to this Annual Report on Form 10-K. The agreements have been filed to provide investors with information regarding their respective terms. The agreements are not intended to provide any other factual information about PostRock or its business or operations. In particular, the assertions embodied in any representations, warranties and covenants contained in the agreements may be subject to qualifications with respect to knowledge and materiality different from those applicable to investors and may be qualified by information in confidential disclosure schedules not included with the exhibits. These disclosure schedules may contain information that modifies, qualifies and creates exceptions to the representations, warranties and covenants set forth in the agreements. Moreover, certain representations, warranties and covenants in the agreements may have been used for the purpose of allocating risk between the parties, rather than establishing matters as facts. In addition, information concerning the subject matter of the representations, warranties and covenants may have changed after the date of the respective agreement, which subsequent information may or may not be fully reflected in our public disclosures. Accordingly, investors should not rely on the representations, warranties and covenants in the agreements as characterizations of the actual state of facts about PostRock or its business or operations on the date hereof.