Bonanza Creek Energy, Inc.
Form 424B4
December 19, 2011

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Table of Contents

Filed Pursuant to Rule 424(b)(4)
Commission File No. 333-174765

PROSPECTUS

10,000,000 Shares

Bonanza Creek Energy, Inc.

COMMON STOCK

Bonanza Creek Energy, Inc. is offering 10,000,000 shares of its common stock. This is our initial public offering, and no public market currently exists for our shares.

Our common stock has been approved for listing on the New York Stock Exchange under the symbol "BCEI."

Investing in our common stock involves risks. See "Risk Factors" beginning on page 16.

PRICE $17.00 A SHARE

	Price to Public	***Underwriting Discounts and Commissions***	***Proceeds to Bonanza Creek***
Per Share	*$17.00*	*$1.105*	*$15.895*
Total	*$170,000,000*	*$11,050,000*	*$158,950,000*

We have also granted the underwriters the right to purchase up to an additional 1,500,000 shares to cover over-allotments.

The Securities and Exchange Commission and state securities regulators have not approved or disapproved of these securities, or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to purchasers on or about December 20, 2011.

MORGAN STANLEY *CREDIT SUISSE*

RAYMOND JAMES *RBC CAPITAL MARKETS* *BMO CAPITAL MARKETS*
HOWARD WEIL INCORPORATED *KEYBANC CAPITAL MARKETS* *STIFEL NICOLAUS WEISEL*
BNP PARIBAS *SOCIETE GENERALE*
December 15, 2011

Table of Contents

Table of Contents

TABLE OF CONTENTS

You should rely only on the information contained in this prospectus and any free writing prospectus prepared by or on behalf of us or to which we have referred you. We have not authorized anyone to provide you with information different from that contained in this prospectus and any free writing prospectus. We are offering to sell shares of common stock and seeking offers to buy shares of common stock only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the common stock.

Until January 9, 2012 (the 25th day after the date of this prospectus), all dealers that buy, sell or trade our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This requirement is in addition to the dealers' obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is also based on our good faith estimates. Industry publications and other published independent sources generally state that they have obtained information from sources believed to be reliable but do not guarantee the accuracy and completeness of such information. Although we believe these third-party sources are reliable and that the information is accurate and complete, neither we nor the underwriters have independently verified the information. Likewise, we believe our internal research is reliable, but it has not been verified by any independent sources.

Table of Contents

PROSPECTUS SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. Because it is abbreviated, this summary does not contain all of the information that you should consider before investing in our common stock. You should read the entire prospectus carefully before making an investment decision, including the information presented under the headings "Risk Factors," "Cautionary Note Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements and unaudited pro forma financial information and related notes thereto included elsewhere in this prospectus. Unless otherwise indicated, information presented in this prospectus assumes that the underwriters' option to purchase additional common shares is not exercised. We have provided definitions for certain oil and natural gas terms used in this prospectus in the "Glossary of Certain Industry Terms" beginning on page 143 of this prospectus.

In this prospectus, unless the context otherwise requires, the terms "we," "us," "our" and the "company" refer to Bonanza Creek Energy, Inc. and its subsidiaries and Bonanza Creek Energy Company, LLC, its predecessor.

BONANZA CREEK ENERGY, INC.

Overview

Bonanza Creek Energy, Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. Our assets and operations are concentrated primarily in southern Arkansas (Mid-Continent region) and the Denver Julesburg ("DJ") and North Park Basins in Colorado (Rocky Mountain region). In addition, we own and operate oil producing assets in the San Joaquin Basin (California region). Our management team has extensive experience in acquiring and operating oil and gas properties, which we believe will contribute to the development of our sizable inventory of projects including those targeting the oily Cotton Valley sands in our Mid-Continent region and the Niobrara oil shale formation in our Rocky Mountain region. We operate approximately 99.4% and hold an average working interest of approximately 85.8% of our proved reserves, providing us with significant control over the rate of development of our long-lived, low-cost asset base.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves to be 32,860 MBoe as of December 31, 2010, 68.1% of which were classified as oil and natural gas liquids, and 35.1% of which were classified as proved developed. Our average net daily production rate during November 2011 was 6,105 Boe/d, which consisted of 71% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2010(1)					Estimated Production for the Month Ended November 30, 2011			
	Total Proved (MBoe)	% of Total	% Proved Developed	% Oil and Liquids	PV-10 ($ in MM)(2)	Average Net Daily Production (Boe/d)	% of Total	Projected 2011 Capital Expenditures (millions)(3)	Net Proved Undeveloped Drilling Locations as of December 31, 2010
Mid-Continent	22,876	69.6%	26.2%	67.3%	$ 313.3	3,223	52.8%	$ 85.2	151.3
Rocky Mountain	9,098	27.7	57.2	67.1	135.3	2,706	44.3	74.9	77.3
California	886	2.7	38.3	98.8	13.0	176	2.9	2.0	13.6
Total	32,860	100.0%	35.1%	68.1%	$ 461.6	6,105	100%	$ 162.1	242.2

(1) Proved reserves were calculated using prices equal to the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months, which were $79.43 per Bbl of crude oil and $4.38 per MMBtu of natural gas. Adjustments were made for location and the

1

Table of Contents

grade of the underlying resource, which resulted in an average decrease of $4.50 per Bbl of crude oil and an increase of $0.43 per MMBtu of natural gas.

(2)
PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure of Discounted Future Net Cash Flows ("Standardized Measure") because it does not include the effect of future income taxes. For a reconciliation of our Standardized Measure to PV-10, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation PV-10*."

(3)
Projected capital expenditures for our Mid-Continent region include $17.7 million for the construction of the Dorcheat gas processing facility, which was completed in September 2011.

Development Projects by Region

Mid-Continent: In southern Arkansas, we are primarily targeting the oil-bearing Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton fields. As of December 31, 2010, our estimated proved reserves in this region were 22,876 MBoe, 67.3% of which were oil and natural gas liquids and 26.2% of which were proved developed. We currently operate 138 gross (120.5 net) producing wells and, as of December 31, 2010, had an identified drilling inventory of approximately 188 gross (151.3 net) PUD drilling locations on our acreage. In 2011 we expect to drill and complete 40 gross (34.9 net) wells in the Dorcheat Macedonia field at a cost of approximately $1.7 million per well, and 2 gross (2.0 net) wells in the McKamie Patton field at a cost of approximately $1.2 million per well. As of October 31, 2011 we have drilled 36 gross (31.5 net) wells in the Dorcheat Macedonia field.

We also own and operate the McKamie and Dorcheat gas processing facilities and approximately 150 miles of associated gathering pipelines that serve our acreage position in southern Arkansas. These facilities have a combined maximum processing capacity of 27.5 MMcf/d of natural gas and 30,000 gallons per day of natural gas liquids. These two facilities currently process all of the natural gas that we produce from the Dorcheat Macedonia and McKamie Patton fields.

Rocky Mountain: In the DJ and North Park Basins in Colorado, we hold 83,617 gross (62,688 net) acres that currently produce oil, natural gas and CO_2 from the Pierre B, Niobrara, Codell, J-Sand, D-Sand and Dakota formations. As of December 31, 2010, our estimated proved reserves in this region were 9,098 MBoe, of which 67.1% were oil and 57.2% were proved developed. In the DJ Basin we control 29,262 net acres and, as of December 31, 2010, have identified approximately 93 gross (73.3 net) vertical PUD drilling locations targeting the Codell sand and Niobrara oil shale formations. In 2011, we expect to drill and complete 64 gross (63.0 net) vertical wells targeting the Codell sand and Niobrara oil shale formations, at a cost of approximately $0.8 million per well. As of October 31, 2011, we have completed 64 gross (63.0 net) of our planned 2011 wells. In addition, we believe that horizontal drilling and multi-stage fracture completion techniques are an attractive alternative to vertical well completions for the Niobrara oil shale. To date, we have drilled all four, and completed three, of our operated horizontal Niobrara wells in the DJ Basin planned for 2011. In the North Park Basin we control 33,426 net acres and, as of December 31, 2010, have identified 4 gross (4.0 net) vertical PUD locations. We have identified highly fractured and dual porosity areas which we believe will support vertical and horizontal drilling techniques for the Niobrara. The development and testing of the North Park Basin began this year with the drilling of 2 gross (2.0 net) vertical wells at a drilling and evaluation cost of approximately $2.9 million for the first well and an estimated $2.2 million for the second well.

California: In California, we employ thermal techniques to recover heavy oil in the Kern River and Midway Sunset fields, and we produce medium gravity oil from the Greeley and Sargent fields. As of December 31, 2010, our estimated proved reserves in this region were 886 MBoe, of which 98.8% were oil and 38.3% were proved developed. We have identified approximately 18 gross (13.6 net) PUD drilling opportunities in these fields. In 2011, we expect to drill 3 gross (1.5 net) wells with individual well costs ranging from approximately $0.3 to $1.0 million. As of October 31, 2011, we have drilled and completed 3 gross (1.5 net) wells.

Recent Developments

On July 24, 2011, we completed our first operated horizontal Niobrara well, the State Antelope 11-2Hz, and reported a 24-hour rate after cleanup on August 1, 2011 of 738 Boe/d and a 30-day rate of 362 Boe/d. Our second operated horizontal Niobrara well, the North Platte 44-11-28Hz, was completed on August 9, 2011 and reported a 24-hour rate after cleanup on August 19, 2011 of 887 Boe/d and a 30-day rate of 599 Boe/d. These two wells cost an average of $3.9 million per well. We recently completed our third operated horizontal Niobrara well, the State Antelope 11-14-1Hz, reporting a 24-hour rate after cleanup on November 1, 2011 of 886 Boe/d. Our fourth and final operated horizontal Niobrara well of 2011, the State Whitetail 14-11-36Hz, has been drilled and is currently being fracture stimulated. We expect costs for these two wells to average $4.3 million per well.

We recently approved our 2012 capital expenditure budget, pursuant to which we expect to spend approximately $250 million to continue developing our oil and gas properties across our regions and to expand our gas processing facilities in southern Arkansas.

Our Business Strategies

Our goal is to increase stockholder value by investing capital to increase our production, cash flow and proved reserves. We intend to accomplish this goal by focusing on the following key strategies:

Increase Production from Existing Low-Cost Proved Inventory. In the near term, we intend to accelerate the drilling of our lower-risk vertical PUD drilling locations in southern Arkansas and in the oily Codell and Niobrara formations of the DJ Basin. Substantially all of these infill locations are characterized by multiple productive horizons.

Test and Evaluate Our Niobrara Oil Shale Acreage. We hold approximately 83,617 gross (62,688 net) acres prospective for the development of the Niobrara oil shale in Weld and Jackson Counties, Colorado, and own approximately 17,400 acres of proprietary 3-D seismic data covering our acreage position in Weld County, which aids in identifying our horizontal drilling locations. Although full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, we and other operators in the region, including Noble Energy (DJ Basin), Anadarko Petroleum (DJ Basin), EOG Resources (DJ Basin and North Park Basin), and PDC Energy (DJ Basin) have recently applied horizontal drilling and multi-stage fracture stimulation techniques to enhance recoveries and economic returns.

Exploit Additional Development Opportunities. We are evaluating additional resource potential opportunities that could result in future development projects on several of our assets. For example, we have evaluated and believe we may achieve attractive returns by exploiting the Lower Smackover (Brown Dense) trend in our southern Arkansas acreage. We have 5,672 net acres prospective for the Brown Dense. Finally, we believe there are additional thermal recovery opportunities in California.

Pursue Accretive Acquisitions. We intend to pursue bolt-on acquisitions in regions where we operate and where we believe we possess a strategic or technical advantage, such as southern Arkansas where we own a gas processing facility and the associated infrastructure. In addition, we intend to focus on other oil and liquids-rich opportunities where we believe our operational experience will enhance the value and performance of acquired properties.

Table of Contents

Maintain High Degree of Operatorship. We currently have and intend to maintain a high working interest in our assets, thereby allowing us to leverage our technical, operating and management skills and control the timing of our capital expenditures.

Our Competitive Strengths

We believe the following combination of strengths will enable us to implement our strategies:

Significant Drilling Inventory. We have identified 303 gross (242.2 net) PUD drilling locations, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. Since 2005, we have accumulated 62,688 net acres in Weld and Jackson Counties, Colorado, targeting the Niobrara formation. Our acreage is proximate to horizontal drilling operations which have been successfully completed by other operators. Significant increases in permitting, spud notices and reported oil and gas production involving the Niobrara formation in these counties have made this area one of the most active oil shale plays in the United States. In Weld County, the average initial 30-day production rate is 318 Boe/d from 70 wells with oil and gas production and no dry holes reported to the state regulatory commission. In the North Park Basin, EOG Resources has completed seven wells horizontally in an area of the Niobrara that we believe to be geologically similar to our acreage position based on electric and porosity log response. The average initial 30-day production rate from these wells has been 294 Boe/d.

We believe our significant acreage position in the Niobrara represents production, reserve and value growth potential and that the continued development of this play by other operators validates our investment in this play and will result in the continued development of infrastructure in the area. Geological risks associated with our Weld County acreage position have been mitigated by the high volume of data provided through the drilling, completion and production of thousands of vertical wells in the Niobrara in close proximity to and within our acreage. We own proprietary 3-D seismic surveys on 17,400 acres of our properties in Weld County and 22 proprietary 2-D seismic lines in Jackson County. Additionally, adequate gathering systems are in place in this region, enabling a short time period from well completion to first product sales.

High Degree of Operational Control. We hold an average working interest in our properties of approximately 85.8% and operate approximately 99.4% of our estimated proved reserves, which allows us to employ the drilling and completion techniques we believe to be most effective, manage costs and control the timing and allocation of our capital expenditures.

Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie facility improves our well development economics in southern Arkansas. In addition, we expanded our infrastructure by adding an additional gas processing facility in our Dorcheat Macedonia field to accommodate future drilling on our acreage in this region.

Experienced Management. Our senior management team averages more than 31 years of experience, and certain members of our executive management have worked together for over 24 years. Our management team has significant acquisition experience, having negotiated and closed more than 12 acquisition transactions since 2006.

Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. As adjusted for the completion of this offering, our liquidity as of October 31, 2011 was approximately $232.0 million, comprised of $220 million of availability under our credit facility and approximately $12.0 million of cash on hand.

Table of Contents

Corporate Restructuring

On December 23, 2010, our predecessor, Bonanza Creek Energy Company, LLC ("BCEC") was recapitalized through the following series of transactions (collectively referred to as our "Corporate Restructuring"):

- we issued shares of our common stock to Project Black Bear LP ("Black Bear"), an entity advised by West Face Capital Inc. ("West Face Capital"), and to certain clients of Alberta Investment Management Corporation ("AIMCo") in exchange for $265 million in cash;

- BCEC contributed to us all of its ownership interest in Bonanza Creek Energy Operating Company, LLC ("BCEOC") in exchange for shares of our common stock;

- members of Holmes Eastern Company, LLC ("HEC") contributed all of their outstanding membership interests in HEC to us in exchange for cash and shares of our common stock; and

- we repaid certain of BCEC's indebtedness and assumed the remaining balance outstanding under BCEC's credit facility.

Following completion of these transactions, BCEC was dissolved and the shares of our common stock held by BCEC were distributed for the benefit of its members.

Credit Facility

On March 29, 2011, we entered into a four-year $300 million credit agreement with a syndicate of banks providing for a senior secured revolving credit facility with an initial borrowing base of $130 million and with a $5 million subfacility for standby letters of credit. As of December 2, 2011, the borrowing base under our credit facility is $220 million with a $15 million subfacility for standby letters of credit. For a description of the material terms of our credit facility, see "*Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit facility.*"

Class B Common Stock Conversion

Immediately prior to the consummation of this offering, 10,000 shares of our Class B common stock, par value $0.001 per share ("Class B Common Stock"), issued in the form of shares of restricted stock to certain of our employees pursuant to our Management Incentive Plan, will automatically be converted into a number of shares of our Class A Common Stock pursuant to a formula set forth in our amended and restated certificate of incorporation. Such shares of our Class A Common Stock subsequently will be reclassified as shares of our common stock pursuant to our second amended and restated certificate of incorporation. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*." We expect to issue 437,787 shares of our common stock upon conversion of the Class B Common Stock and reclassification of our Class A Common Stock.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. In particular, the following considerations may offset our competitive strengths or have a negative effect on our ability to execute our business strategies as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- Our future revenues are dependent on our ability to successfully replace our proved producing reserves.

Table of Contents

A decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our identified drilling locations are scheduled over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Unless we replace our oil and gas reserves, our reserves and production will decline.

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

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

We have incurred losses from operations during certain periods since our inception and may continue to do so in the future.

For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, see "*Risk Factors*" beginning on page 16 and "*Cautionary Note Regarding Forward-Looking Statements*."

Principal Stockholders

Our principal stockholder, Black Bear, is an affiliate of West Face Capital, a Toronto-based investment management firm with over $2.0 billion of assets under management. West Face Capital specializes in event-oriented investments where its ability to navigate complex investment processes is the most significant determinant of returns and invests across the capital structure with specializations in natural resource industries, distressed debt, high yield debt and common equity. West Face Capital indirectly holds its interest in our common stock through Black Bear, a Delaware limited partnership formed by West Face Capital as a special purpose vehicle to invest in our securities on behalf of its limited partner investors. Pursuant to an advisory agreement, West Face Capital has authority to direct the trading and investing activities of Black Bear, including the power to vote and control the disposition of the shares of our Class A Common Stock held by Black Bear (approximately 46.63% of our issued and outstanding shares prior to this offering). West Face Capital and AIMCo, on behalf of certain of its clients, have entered into an investment management agreement pursuant to which West Face Capital has the right to vote the shares of our common stock held by certain clients of AIMCo. West Face Capital, via the investment management agreement with AIMCo and an advisory agreement with Black Bear, has the power to vote 72.66% of our issued and outstanding common stock prior to this offering and 53.50% after this offering, and, therefore, may exercise significant control over the outcome of matters submitted to a vote of the stockholders, including the election of our board of directors.

Corporate Information

Our principal executive offices are located at 410 17th Street, Suite 1500, Denver, Colorado 80202, and our telephone number at that address is (720) 440-6100. Our website is www.bonanzacrk.com. Information on our website or any other website is not incorporated by reference herein and does not constitute a part of this prospectus.

Table of Contents

THE OFFERING

Common stock offered by us.	10,000,000 shares
Common stock to be outstanding after this offering	39,560,308 shares (41,060,308 shares if the underwriters exercise their over-allotment option in full)
Over-allotment option	1,500,000 shares
Use of proceeds	We estimate that our net proceeds from the sale of common stock in this offering will be approximately $156.0 million, or $179.8 million if the underwriters exercise their over-allotment option in full, in each case after deducting estimated expenses and underwriting discounts and commissions. We intend to use a portion of the net proceeds from this offering to repay the outstanding indebtedness under our credit facility, which as of October 31, 2011, was approximately $149.1 million. We intend to use the remaining $6.9 million, or $30.7 million if the underwriters exercise their over-allotment option in full, of net proceeds from this offering, together with borrowings under our credit facility, to fund our drilling and development program and the expansion of our gas processing facilities. As of October 31, 2011, our cash and cash equivalents, as adjusted to give effect to this offering and the application of the net proceeds, was $12.0 million, or $35.8 million if the underwriters exercise their over-allotment option in full. Affiliates of certain of the underwriters are lenders and agents under our credit facility and, accordingly, will receive a portion of the net proceeds from this offering through the repayment of outstanding borrowings under the credit facility. See "*Underwriters; Conflicts of Interest*."
Dividend policy	We do not intend to pay any cash dividends on our common stock. We intend to retain any earnings for use in the operation of our business and to fund future growth. In addition, our credit facility prohibits us from paying cash dividends. See "*Dividend Policy*."
New York Stock Exchange listing	Our common stock has been approved for listing on the NYSE under the symbol "BCEI."
Risk factors	You should carefully read and consider the information beginning on page 16 of this prospectus set forth under the heading "*Risk Factors*" and all other information set forth in this prospectus before deciding to invest in our common stock.

Unless specifically stated otherwise, all information in this prospectus:

- gives effect to the conversion of all shares of Class B Common Stock into 437,787 shares of Class A Common Stock and the subsequent reclassification of our Class A Common Stock immediately prior to this offering; and

- assumes no exercise of the over-allotment option.

Table of Contents

SUMMARY HISTORICAL AND PRO FORMA CONSOLIDATED FINANCIAL DATA

The following tables set forth summary historical and pro forma financial data of us and our predecessor, BCEC and pro forma financial data to give effect to the acquisition of HEC as of and for the periods indicated. The consolidated statement of operations data for the years ended December 31, 2008 and 2009 and the period ended December 23, 2010 are derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2010 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2009 is derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2008 is derived from the audited consolidated financial statements of BCEC which are not included in this prospectus. The consolidated statement of operations data for the nine months ended September 30, 2010 are derived from the unaudited financial statements of BCEC appearing elsewhere in this prospectus, and the consolidated statement of operations data for the period from inception (December 23, 2010) to December 31, 2010 and the nine months ended September 30, 2011 and the consolidated balance sheet data as of September 30, 2011 are derived from our financial statements appearing elsewhere in this prospectus. In management's opinion, these financial statements include all adjustments necessary for the fair presentation of our financial condition as of such dates and our results of operations for such periods.

The summary unaudited pro forma statement of operations of Bonanza Creek Energy, Inc. for the year ended December 31, 2010 gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The summary unaudited balance sheet of Bonanza Creek Energy, Inc. as of September 30, 2011 gives effect to this offering and the repayment of indebtedness as if they had occurred on September 30, 2011.

The summary historical and pro forma consolidated financial data should be read in conjunction with "*Selected Historical Consolidated and Unaudited Pro Forma Financial Data*" and "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and both our and our predecessor's financial statements and the notes to those financial statements included elsewhere in this document. The financial information included in this prospectus may not be indicative of our future results of operations, financial position and cash flows.

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		Bonanza Creek Energy, Inc. Pro Forma[(2)]
	Year Ended December 31, 2008	Year Ended December 31, 2009	Period Ended December 23, 2010[(1)]	Nine Months Ended September 30, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011	Year Ended December 31, 2010
				(unaudited)		(unaudited)	(unaudited)
	(in thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil sales	$ 39,967	$ 27,601	$ 34,431	$ 24,412	$ 1,325	$ 57,177	$ 45,413
Natural gas sales	5,165	3,671	6,226	4,807	207	9,283	10,253
Natural gas liquids and CO_2 sales	2,782	3,169	7,672	5,469	213	9,076	8,365
Total revenues	$ 47,914	$ 34,441	$ 48,329	$ 34,688	$ 1,745	$ 75,536	$ 64,031
Operating expenses:							
Lease operating	20,434	13,449	14,792	10,581	483	14,461	17,285
Severance and ad valorem taxes	1,847	2,148	1,621	1,055	70	3,860	2,524
Depreciation, depletion and amortization	25,463	14,108	14,225	11,554	506	21,083	20,917
General and administrative	7,477	7,610	8,375	6,289	323	9,116	9,338
Employee stock compensation[(3)]							
Exploration	25	131	361	202		573	380
Impairment of oil and gas properties[(4)]	26,437	579				4,067	
Cancelled private placement[(5)]			2,378	2,378			2,378
Total operating expenses	$ 81,683	$ 38,025	$ 41,752	$ 32,059	$ 1,382	$ 53,160	$ 52,822
Income (loss) from operations	(33,769)	(3,584)	6,577	2,629	363	22,376	11,209
Other income (expense):							
Interest expense	(12,870)	(16,582)	(18,001)	(13,494)	(58)	(2,687)	(1,263)
Amortization of debt discount	(5,987)	(7,963)	(8,862)	(6,556)			
Write off of deferred financing costs			(1,663)	(1,663)			(1,663)
Gain on sale of oil and gas properties	8	303	4,055	4,055			4,055
Unrealized gain (loss) in fair value of warrant put option[(6)]	70,972	(80,640)	34,345	23,672			
Unrealized gain (loss) in fair value of commodity derivatives	48,716	(34,589)	(7,605)	(2,523)	(514)	7,096	(8,119)
Realized gain (loss) on settled commodity derivatives	1,913	13,451	5,919	4,897	(47)	(2,353)	5,872
Other income (loss)	(229)	(179)	19	125		(100)	(47)

Total other income (expense)	102,523	(126,199)	8,207	8,513	(619)	1,956	(1,165)
Income (loss) before income taxes	68,754	(129,783)	14,784	11,142	(256)	24,332	10,044
Income tax benefit (expense)(7)					94	(11,464)	(3,696)
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ 11,142	$ (162)	$ 12,868	$ 6,348
Net income per common share(8)							
Basic					$ (0.01)	$ 0.44	
Diluted					$ (0.01)	$ 0.44	
Weighted average shares outstanding							
Basic					29,123	29,123	
Diluted					29,123	29,123	

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(1) We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEC for the period ended December 23, 2010 are included in the statement of operations presented above.

(2) The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010.

(3) We will recognize employee stock-based compensation expense immediately prior to the consummation of this offering. We also expect to have stock-based compensation expense for future awards. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations Selected Factors and Trends Affecting Our Results of Operations Stock-based Employee Compensation Expenses.*"

(4) The impairment for the year ended 2008 resulted from a write-down of the carrying value of our oil and natural gas reserves due to depressed year-end oil and natural gas prices.

Table of Contents

(5) Expenditures in connection with a cancelled private placement of our preferred stock.

(6) In connection with its purchase of our senior subordinated notes, D. E. Shaw Synoptic Portfolios 5, L.L.C. received warrants to purchase equity interests in our predecessor. These warrants contained a put right exercisable beginning on May 17, 2014. The periods presented for our predecessor reflect the changes in the fair market value of that put option. The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(7) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a corporation at an estimated combined state and federal income tax rate of 36.8%.

(8) As a limited liability company, ownership interests in our predecessor were held as membership interest units rather than shares.

	Bonanza Creek Energy Company, LLC (Predecessor)		**Bonanza Creek Energy, Inc.**		
	As of December 31,		**As of December 31, 2010**	**As of September 30, 2011**	**As of September 30, 2011 As Adjusted(1)**
	2008	**2009**		**(unaudited)**	**(unaudited)**
			(in thousands)		
Balance Sheet Data:					
Cash and cash equivalents	$ 4,088	$ 2,522	$	$ 153	$ 24,003
Property and equipment, net	195,280	188,367	496,582	596,454	596,454
Total assets	241,625	211,552	516,104	626,903	650,753
Long term debt, including current portion:					
Credit facility	107,000	99,000	55,400	132,100	
Senior subordinated notes, net of discount	75,499	92,442			
Second lien term loan(2)					
Subordinated unsecured note	10,000	10,799			
Warrant put options(3)	828	81,468			
Total members'/stockholders' equity (deficit)	35,988	(93,795)	356,380	369,317	525,267

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)					Bonanza Creek Energy, Inc.
	Year Ended December 31,		Period Ended December 23, 2010[4]	Nine Months Ended September 30, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011
	2008	2009				
				(unaudited)		(unaudited)
	(in thousands)					
Other Financial Data:						
Net cash provided by operating activities	$ 11,128	$ 11,134	$ 22,759	$ 14,141	$ (1,633)	$ 37,333
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,127)	(17,265)	(817)	(110,852)
Net cash provided by (used in) financing activities	72,541	(5,515)	9,297	(2,857)		73,671
Adjusted EBITDAX[5]	14,435	19,067	25,071	18,414	822	45,646

(1) As adjusted for this offering and the application of proceeds as described in "*Use of Proceeds*."

(2) Our $30 million second lien term loan was fully funded on May 7, 2010 and repaid in full in connection with our Corporate Restructuring on December 23, 2010.

(3) Warrants and the aggregate warrant exercise price were exchanged for our common shares in connection with our Corporate Restructuring on December 23, 2010.

(4) We completed our Corporate Restructuring on December 23, 2010. The cash flows from BCEC's operations for the audited period from January 1, 2010 to December 23, 2010 are included in the results presented above.

(5) Adjusted EBITDAX is an unaudited non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net income (loss) and to net cash provided by (used in) operating activities, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation Adjusted EBITDAX*," below.

Table of Contents

SUMMARY RESERVE AND OPERATIONS DATA

The following tables present summary information regarding the estimated net proved oil and natural gas reserves and the historical operating data of us, our predecessor BCEC, and HEC, as of the dates indicated. The estimates of our net proved reserves at December 31, 2010 and of BCEC at December 31, 2009 are based on the December 31, 2010 and 2009 reserve reports prepared by Cawley, Gillespie & Associates, Inc., our independent reserve engineers. The December 31, 2008 estimates of net proved reserves of BCEC are based on a reserve report prepared by MHA Petroleum Consultants LLC, independent reserve engineers.

For additional information regarding our reserves, please see "*Business Development Projects by Region*" and Note 14 to our audited consolidated financial statements included elsewhere in this prospectus.

	Bonanza Creek Energy Company, LLC (Predecessor)		Bonanza Creek Energy, Inc.
	As of December 31,		
	2008	2009[1]	2010[2]
Estimated Proved Reserves:			
Crude oil (MBbls)	11,294	12,913	18,601
Natural gas (MMcf)	19,906	27,610	62,884
Natural gas liquids (MBbls)	1,162	2,357	3,778
Total proved (MBoe)[3]	15,774	19,872	32,860
Proved developed producing (MBoe)	4,550	4,540	7,478
Proved developed non-producing (MBoe)	1,549	1,340	4,048
Total proved developed (MBoe)	6,099	5,880	11,526
Proved undeveloped (MBoe)	9,675	13,992	21,335
PV-10 ($ in millions)[4]	$ 84.7	$ 208.2	$ 461.6

(1) The 2009 reserve report excludes proved reserves attributable to our ownership in the Jasmin property in California, which we sold on March 31, 2010. At December 31, 2009, the Jasmin property had proved developed and total proved reserves of 401 MBoe and 568 MBoe, respectively, and a PV-10 value of $7.9 million.

(2) The 2010 reserve report includes proved reserves attributable to our ownership in HEC properties in Colorado and Arkansas, which we acquired on December 23, 2010. At December 31, 2010, HEC properties had proved developed and total proved reserves of 2,803 MBoe and 9,339 MBoe, respectively, and a PV-10 value of $113.1 million.

(3) Determined using the ratio of 6 Mcf of natural gas being equivalent to one Bbl of crude oil.

(4) PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure because it does not include the effect of future income taxes. A reconciliation of our Standardized Measure of Discounted Net Cash Flows to PV-10 is provided under " *Non-GAAP Financial Measures and Reconciliation PV-10*," below.

12

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		Holmes Eastern Company, LLC	Bonanza Creek Energy, Inc. Pro Forma(2)
	Year Ended December 31,		Period Ended December 23,	Nine Months Ended September 30,	Period from Inception (December 23, 2010) to December 31,	Nine Months Ended September 30,	Period Ended December 23,	Year Ended December 31,
	2008	2009	2010(1)	2010	2010	2011	2010(1)	2010
Net Sales Data:								
Crude oil (MBbls)	453.7	507.4	469.0	342.5	15.9	634.4	129.1	614.1
Natural gas (MMcf)	668.9	939.0	1,308.5	969.1	43.0	1,822.8	780.6	2,132.2
Natural gas liquids (MBbls)	35.5	69.1	126.5	91.8	3.3	128.8	8.7	138.4
CO_2 (MMcf)	663.0	217.1	533.1	464.3	4.5	232.0		537.6
Crude oil equivalent (MBoe)(3)	600.7	733.0	813.6	595.7	26.4	1,066.9	267.9	1,107.9
Average daily volumes (Boe/day)(3)	1,641	2,008	2,279	2,182	3,297	3,908	750	3,035
Average Sales Price (Before Hedging)(4):								
Crude oil (per Bbl)	$ 88.09	$ 54.40	$ 73.41	$ 71.29	$ 83.24	$ 90.13	$ 74.78	$ 73.95
Natural gas (per Mcf)	7.72	3.91	4.76	4.96	4.80	5.09	4.89	4.81
Natural gas liquids (per Bbl)	57.45	41.77	56.04	54.09	63.42	68.56	55.46	56.18
CO_2 (per Mcf)	1.12	1.30	1.09	1.09	1.12	1.07		1.09
Average equivalent price (per Boe)(3)	78.53	46.60	58.69	57.38	65.98	70.57	52.10	57.27
Average Sales Price (After Hedging)(4):								
Crude oil (per Bbl)	$ 79.59	$ 67.40	$ 75.07	$ 73.34	$ 81.18	$ 85.67	$ 74.78	$ 74.47
Natural gas (per Mcf)	7.93	5.05	5.01	5.51	4.48	5.36	4.89	5.16
Natural gas liquids (per Bbl)	57.45	41.77	56.04	54.09	63.42	68.56	55.46	56.18
CO_2 (per Mcf)	1.12	1.30	1.09	1.09	1.12	1.07		1.09
Average equivalent price (per Boe)(3)	72.35	57.07	60.05	59.45	64.21	68.36	52.10	58.22
Expenses (per Boe)(3):								
Lease operating expenses	$ 34.02	$ 18.35	$ 18.18	$ 17.76	$ 18.31	$ 13.55	$ 7.50	$ 15.60
Severance and ad valorem taxes	3.07	2.93	1.99	1.77	2.65	3.62	3.11	2.28
General and administrative	12.45	10.38	13.22	10.56	12.27	8.54	2.37	10.58
Depreciation, depletion and amortization	42.39	19.25	17.48	19.40	19.20	19.76	11.22	15.85

(1) We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEC for the period ended December 23, 2010 are included in the results presented above.

(2) Pro forma for our Corporate Restructuring as if it had occurred as of January 1, 2010.

(3) Does not include data relating to sales of CO_2.

(4) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

Non-GAAP Financial Measures and Reconciliation

Adjusted EBITDAX

Adjusted EBITDAX is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and

Table of Contents

rating agencies and is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP.

We define Adjusted EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, property impairments, exploration expenses, unrealized derivative gains and losses, non-cash stock-based compensation expense and the other items listed below.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that Adjusted EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

The following tables present a reconciliation of the non-GAAP financial measure of Adjusted EBITDAX to the GAAP financial measures of net income (loss) and net cash provided by (used in) operating activities, respectively.

	Bonanza Creek Energy Company, LLC (Predecessor)				**Bonanza Creek Energy, Inc.**	
	Year Ended December 31,					
	2008	**2009**	**Period Ended December 23, 2010[(1)]**	**Nine Months Ended September 30, 2010**	**Period from Inception (December 23, 2010) to December 31, 2010**	**Nine Months Ended September 30, 2011**
	(in thousands)					
Adjusted EBITDAX Reconciliation to Net Income (Loss):						
Net income (loss)	$ 68,754	$ (129,783)	$ 14,784	$ 11,142	$ (162)	$ 12,868
Changes in unrealized (gain) loss on derivative instruments	(119,689)	115,229	(26,740)	(21,149)	514	(7,096)
Change in unrealized loss on derivative liability assumed	(5,403)	(5,439)	(4,407)	(3,371)		
Income taxes					(94)	11,464
Cancelled private placement			2,378	2,378		
(Gain) on sale of properties	(8)	(303)	(4,055)	(4,055)		
Accretion of debt discount	5,986	7,963	8,862	6,556		
Write off of deferred financing costs			1,663	1,663		
Interest expense	12,870	16,582	18,001	13,494	58	2,687
Depreciation, depletion and amortization	25,463	14,108	14,225	11,554	506	21,083
Impairment of oil and gas properties	26,437	579				4,067
Exploration expenses	25	131	360	202		573
Adjusted EBITDAX	$ 14,435	$ 19,067	$ 25,071	$ 18,414	$ 822	$ 45,646

Table of Contents

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.	
	Year Ended December 31,		Period Ended December 23, 2010(1)	Nine Months Ended September 30, 2010	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011
	2008	2009				
	(in thousands)					
Adjusted EBITDAX Reconciliation to Net Cash Provided By (Used In) Operating Activities:						
Net cash provided by (used in) operating activities	$ 11,128	$ 11,134	$ 22,759	$ 14,141	$ (1,633)	$ 37,333
Cancelled private placement			2,378	2,378		
Interest expense for line of credit excluding amortization of deferred financing costs	5,374	5,159	5,368	3,971	42	1,984
Cash exploration expenses	25	131	318	202		573
Other		(138)				(92)
Provision for losses on accounts receivable	(343)					
Changes in working capital	(1,749)	2,781	(5,752)	(2,278)	2,413	5,848
Adjusted EBITDAX	$ 14,435	$ 19,067	$ 25,071	$ 18,414	$ 822	$ 45,646

(1) We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEC for the period ended December 23, 2010 are included in the results presented above.

PV-10

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure because it does not include the effects of income taxes. Neither PV-10 nor Standardized Measure represents an estimate of fair market value of our natural gas and crude oil properties. PV-10 is used by the industry and by our management as an arbitrary reserve asset value measure to compare against past reserve bases and the reserve bases of other business entities that are not dependent on the taxpaying status of the entity.

The following table provides a reconciliation of our PV-10 to Standardized Measure:

	Bonanza Creek Energy Company, LLC (Predecessor)			Holmes Eastern Company, LLC	Bonanza Creek Energy, Inc. Pro Forma
	As of December 31,			As of December 31,	As of December 31,
(in millions)	2008(1)	2009	2010	2010	2010
PV-10	$ 84.7	$ 208.2	$ 346.6	$ 115.0	$ 461.6
Estimated taxes(2)	(0.8)	(22.5)	(61.5)	(25.3)	(86.9)
Standardized measure	$ 83.9	$ 185.7	$ 285.1	$ 89.7	$ 374.7

(1) As of December 31, 2008 the PV-10, estimated taxes, and Standardized Measure were significantly lower than these metrics as of December 31, 2009 due to SEC reserve pricing of $44.60 per Bbl as of December 31, 2008 as compared to $61.18 per Bbl as of December 31, 2009. Income taxes were further reduced as of December 31, 2008 due to a significant acquisition that took place during

2008 that added significant future income tax deductions for cost depletion and tangible well head equipment depreciation.

(2) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Historically, federal or state corporate income taxes have been passed through to BCEC's members. However, as a corporation, we are subject to U.S. federal and state income taxes. The estimated taxes shown above illustrate the effect of income taxes on net revenues as of December 31, 2008, 2009 and 2010, assuming we had been subject to entity-level tax and further assuming an estimated combined 38.5% federal and state income tax rate.

Table of Contents

RISK FACTORS

An investment in our common stock involves risks. You should carefully consider the risks described below before investing in our common stock. The risks and uncertainties described below are not the only ones we may face. The following risks, together with additional risks and uncertainties not currently known to us or that we may currently deem immaterial, could impair our financial position and results of operations.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our future revenues are dependent on our ability to successfully replace our proved producing reserves.

In general, production from oil and gas properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our current proved reserves will decline as reserves are produced and, therefore, our level of production and cash flows will be affected adversely unless we conduct successful exploration and development activities or acquire properties containing proved reserves. Thus, our future oil and natural gas production and, therefore, our cash flow and income are highly dependent upon our level of success in finding or acquiring additional reserves. However, we cannot assure you that our future acquisition, development and exploration activities will result in any specific amount of additional proved reserves or that we will be able to drill productive wells at acceptable costs.

Exploration and development activities involve numerous risks, including the risk that no commercially productive oil or gas reservoirs will be discovered. In addition, the future cost and timing of drilling, completing and producing wells is often uncertain. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- lack of acceptable prospective acreage;
- inadequate capital resources;
- reductions in oil and natural gas prices;
- unexpected drilling conditions, including pressure or irregularities in formations and equipment failures or accidents;
- adverse weather conditions, such as blizzards and ice storms;
- unavailability or high cost of drilling rigs, equipment or labor;
- title problems;
- compliance with governmental regulations;
- delays imposed by or resulting from compliance with regulatory requirements; and
- mechanical difficulties.

According to estimates included in our December 31, 2010 proved reserve report, if on January 1, 2011 we had ceased all drilling and development, including recompletions, refracs and workovers, then our proved developed producing reserves base would decline at an annual effective rate of 7.7% over 10 years, including 31.7% during the first year. If we fail to replace reserves through drilling, our level of production and cash flows will be affected adversely. Our total proved reserves will decline as reserves are produced unless we conduct other successful exploration and development activities or acquire properties containing proved reserves, or both.

A decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic and political conditions impacting the global supply and demand for oil and natural gas;
- the price and quantity of imports of foreign oil and natural gas;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic and foreign governmental regulations;
- speculation as to the future price of oil and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Further, oil prices and natural gas prices do not necessarily fluctuate in direct relationship to each other. Because approximately 68.1% of our estimated proved reserves as of December 31, 2010 were oil and natural gas liquids reserves, our financial results are more sensitive to movements in oil prices. The price of oil has been extremely volatile, and we expect this volatility to continue. During the year ended December 31, 2010, the daily NYMEX WTI oil spot price ranged from a high of $89.28 per Bbl to a low of $74.52 per Bbl, and the NYMEX natural gas Henry Hub spot price ranged from $5.60 to $3.62 per MMBtu.

Substantially all of our oil production is sold to purchasers under short-term (less than twelve months) contracts at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. Lower prices may also reduce the amount of oil and natural gas that we can produce economically and may affect our proved reserves.

Additionally, as of November 30, we had commodity price hedging agreements on approximately 29% of our estimated Boe production. To the extent we are unhedged or our hedge parties default in their obligations, we have significant exposure to adverse changes in the prices of oil and natural gas that could materially and adversely affect our results of operations.

Our identified drilling locations are scheduled to be developed over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management team has identified and scheduled drilling locations on our acreage over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, oil and natural gas prices, costs and drilling results. The final determination on whether to drill any of these drilling locations will be dependent upon the factors described elsewhere in this prospectus as well as, to some degree, the results of our drilling activities with respect to our proved drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected time-frame or will ever be drilled. As such, our actual drilling activities may be materially different from those presently identified, which could adversely affect our business, results of operations or financial condition.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage.

The terms of certain of our oil and gas leases stipulate that the lease will terminate if not held by production. As of October 31, 2011, 30,296 net acres of our properties in the Rocky Mountain region, specifically 5,476 acres in the DJ Basin and 24,820 acres in the North Park Basin, were not held by production. For these properties, if production in paying quantities is not established on units containing these leases during the next three years, then 43 net acres will expire in 2011, 3,440 net acres will expire in 2012 and 11,355 net acres will expire in 2013. If our leases expire, we will lose our right to develop the related properties.

Our drilling plans for these areas are subject to change based upon various factors, many of which are beyond our control, including drilling results, oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints, and regulatory approvals. Further, some of our acreage is located in governmental sections where we do not hold the majority of the acreage and therefore it is likely that we will not be named operator of these sections. As a non-operating leaseholder we have less control over the timing of drilling and there is therefore additional risk of expirations occurring in sections where we are not the operator. For certain properties in which we are a non-operating leaseholder, we have the right to propose the drilling of wells pursuant to a joint operating agreement. Those properties that are not subject to a joint operating agreement are located in states where state law grants us the right to force pooling, except for our properties located in California, where state law does not grant the right to force pooling.

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

Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus.

In order to prepare our estimates, we must project production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data; the quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

Table of Contents

The present value of future net revenues from our proved reserves will not necessarily be the same as the current market value of our estimated oil and natural gas reserves.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. For the year ended December 31, 2008, we based the estimated discounted future net revenues from our proved reserves on prices and costs in effect at year end in accordance with previous SEC requirements. In accordance with SEC requirements for the years ended December 31, 2009 and 2010, we have based the estimated discounted future net revenues from our proved reserves on the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months without giving effect to derivative transactions. Actual future net revenues from our oil and natural gas properties will be affected by factors such as:

- the actual prices we receive for oil and natural gas;
- our actual development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating discounted future net revenues may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Actual future prices and costs may differ materially from those used in the present value estimates included in this prospectus. If oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2010 would decrease by approximately $100.4 million. If natural gas prices decline by $1.00 per Mcf, then our PV-10 as of December 31, 2010 would decrease by approximately $32.9 million.

We have incurred losses from operations during certain periods since our inception and may continue to do so in the future.

We incurred net operating losses of $33.8 million and $3.6 million in the years ended December 31, 2008 and 2009, respectively. Our development of, and participation in, a large number of prospects in the future will require substantial capital expenditures. The uncertainty and factors described throughout this section may impede our ability to economically find, develop, exploit, and acquire oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows from operating activities in the future.

Part of our strategy involves drilling in existing or emerging shale plays using the latest available horizontal drilling and completion techniques; therefore, the results of our planned exploratory drilling in these plays are subject to drilling and completion technique risks and drilling results may not meet our expectations for reserves or production.

Our operations involve utilizing the latest drilling and completion techniques as developed by us and our service providers in order to maximize cumulative recoveries and therefore generate the highest possible returns. Risks that we face while drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage.

The results of our drilling in new or emerging formations, such as the Niobrara oil shale, are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and consequently we are less able to predict future drilling results in these areas.

Ultimately, the success of these drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems and limited takeaway capacity or otherwise, and/or natural gas and oil prices decline, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write-downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

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

The crude oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of crude oil and natural gas reserves. In 2010, we had $35.5 million of capital and exploration expenditures. Our capital expenditures for 2011 are budgeted to be approximately $162.1 million with $141.3 million allocated for the development and operation of our oil and gas properties. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. In response to continued improvement in commodity prices we may increase our actual capital expenditures. We intend to finance our future capital expenditures primarily through our cash flows from operations, borrowings under our credit facility and the proceeds from this offering; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets.

Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the volume of crude oil and natural gas we are able to produce and sell from existing wells;
- the prices at which our crude oil and natural gas are sold;
- our ability to acquire, locate and produce new reserves; and
- the ability of our banks to lend.

If our revenues or the borrowing base under our credit facility decrease as a result of lower crude oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or cash available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our crude oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

Borrowings under our credit facility are limited by our borrowing base, which is subject to periodic redetermination.

The borrowing base under our credit facility is redetermined at least semi-annually, and the lenders holding $66^2/_3$% of the aggregate commitments or we may request one additional redetermination in each six-month period. Redeterminations are based upon a number of factors, including commodity prices and reserve levels. In addition, our lenders have substantial flexibility to reduce our borrowing base due to subjective factors. Upon a redetermination, we could be required to repay a portion of our bank debt to the extent our outstanding borrowings at such time exceed the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the facility and an acceleration of the loans thereunder.

Our level of indebtedness may increase, reducing our financial flexibility.

We intend to fund our capital expenditures through our cash flow from operations, borrowings under our credit facility and the proceeds from this offering. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves will be impaired if cash flow from operations is reduced and external sources of capital become limited or unavailable. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. Our level of debt could affect our operations in several important ways, including the following:

- a portion of our cash flow from operations would be used to pay interest on borrowings;

- the covenants contained in our credit facility limit our ability to borrow additional funds, pay dividends, dispose of assets or issue shares of preferred stock and otherwise may affect our flexibility in planning for, and reacting to, changes in business conditions;

- a high level of debt may impair our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes;

- a leveraged financial position would make us more vulnerable to economic downturns and decreases in commodity prices, and could limit our ability to withstand competitive pressures; and

- any debt that we incur under our credit facility would be at variable rates which could make us vulnerable to increases in interest rates.

The development and exploitation of certain of our resources is dependent on the funding and construction of additional gas processing capacity.

Our pipeline system that transports the natural gas produced from our properties in the Dorcheat Macedonia and McKamie Patton fields to our gas processing facilities does not have sufficient capacity to deliver anticipated increased volumes of natural gas from further development of the field. As a result, in order to fully develop and exploit our opportunities within the Dorcheat Macedonia and McKamie Patton fields we must construct additional gas processing capacity. Our inability to fund, or timely construct, additional gas processing capacity to service production from the Dorcheat Macedonia and McKamie Patton fields will limit our growth and could materially and adversely affect our results of operations.

Our ability to sell our production and/or receive market prices for our production may be adversely affected by lack of transportation, capacity constraints and interruptions.

The marketability of our production from the Mid-Continent, Rocky Mountain and California regions depends in part upon the availability, proximity and capacity of third-party refineries, natural gas gathering systems and processing facilities. We deliver crude oil and natural gas produced from these areas through trucking services and pipelines that we do not own. The lack of availability or capacity on these systems and facilities could reduce the price offered for our production or result in the shut-in of producing wells or the delay or discontinuance of development plans for properties.

Table of Contents

A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, field labor issues or strikes, or we might voluntarily curtail production in response to market conditions. If a substantial amount of our production is interrupted at the same time, it could adversely affect our cash flow.

Currently, there are no natural gas pipeline systems that service wells in the North Park Basin, which is prospective for the Niobrara oil shale. In addition, we are not aware of any plans to construct a facility necessary to process natural gas produced from this basin. If neither we nor a third party constructs the required pipeline system and processing facility, we may not be able to fully develop our resources in the North Park Basin.

Increased costs of capital could adversely affect our business.

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

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We review our proved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties, which may result in a decrease in the amount available under our credit facility. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future which could have a material adverse effect on our ability to borrow under our credit facility and our results of operations for the periods in which such charges are taken.

Operating hazards, natural disasters or other interruptions of our operations could result in potential liabilities, which may not be fully covered by our insurance.

The oil and gas business generally, and our operations, are subject to certain operating hazards such as:

- well blowouts;
- cratering (catastrophic failure);
- explosions;
- uncontrollable flows of oil, gas or well fluids;
- fires;
- oil spills;
- pollution;
- releases of toxic gas (including releases at our gas processing facilities) or of other substances such as petroleum liquids or drilling fluids, into the environment; and

hazards resulting from the presence of hydrogen sulfide (H_2S) or other contaminants in gas we produce.

Table of Contents

At one of our Arkansas properties, we produce a small amount of gas from eight operated (gross) wells where we have identified the presence of H_2S at levels which would be hazardous in the event of an uncontrolled gas release or unprotected exposure. In addition, our operations in Arkansas are susceptible to damage from natural disasters such as flooding or tornados, which involve increased risks of personal injury, property damage and marketing interruptions. The occurrence of one of these operating hazards may result in injury, loss of life, suspension of operations, environmental damage and remediation and/or governmental investigations and penalties. The payment of any of these liabilities could reduce, or even eliminate, the funds available for exploration and development, or could result in a loss of our properties.

Our insurance might be inadequate to cover our liabilities. Insurance costs are expected to continue to increase over the next few years, and we may decrease coverage and retain more risk to mitigate future cost increases. If we incur substantial liability, and the damages are not covered by insurance or are in excess of policy limits, then our business, results of operations and financial condition may be materially adversely affected.

We carry insurance to reduce our exposure to sudden and accidental environmental contamination but do not have coverage for gradual, long-term contamination. Our policies include operator's extra expense ("OEE") coverage with a $1.0 million limit per occurrence; commercial general liability ("CGL") coverage with a time element pollution limit of $1.0 million per occurrence and in the aggregate; and excess liability coverage with a $10.0 million limit per occurrence and in the aggregate. Our OEE policy provides primary coverage for the cleanup of polluting or contaminating substances caused by a sudden and accidental loss of control of a well at the surface. The CGL and Excess Liability policies also provide sudden and accidental pollution liability coverage, including coverage in excess of the OEE policy limit for pollution caused by a well out of control at the surface. In order to obtain coverage, we must report the event to the insurance company within 90 days after its commencement. The CGL policy also contains a $1.0 million aggregate limit for damage to oil, gas, water or other mineral substances that have not been reduced to physical possession above the surface.

Since hydraulic fracturing activities are part of our operations, they are covered by our insurance against claims made for bodily injury, property damage and clean up costs stemming from a sudden and accidental pollution event, provided that we report the event within 90 days after its commencement. We may not have coverage if the operator is unaware of the pollution event and unable to report the "occurrence" to the insurance company within the required time frame. Nor do we have coverage for gradual, long-term pollution events.

Under certain circumstances, we have agreed to indemnify third parties against losses resulting from our operations. Pursuant to our surface leases, we typically indemnify the surface owner for clean up and remediation of the site. As owner and operator of oil and gas wells and associated gathering systems and pipelines, we typically indemnify the drilling contractor for pollution emanating from the well, while the contractor indemnifies us against pollution emanating from its equipment.

Competition in the oil and natural gas industry is intense, and many of our competitors have resources that are greater than ours.

We operate in a highly competitive environment for acquiring prospects and productive properties, marketing oil and gas and securing equipment and trained personnel. As a relatively small oil and gas company, many of our competitors, major and large independent oil and gas companies, possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to develop and acquire more prospects and productive properties than our financial or personnel resources permit. Our ability to acquire additional prospects and discover reserves in the future will depend on our ability to evaluate and select suitable properties and consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and gas industry. Larger competitors may be better able to withstand sustained periods of unsuccessful drilling and absorb the burden of changes in laws and regulations more easily than we can, which would adversely affect our competitive position. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

We may incur losses as a result of title deficiencies.

We purchase working and revenue interests in oil and natural gas leasehold interests from third parties or directly from the mineral fee owners. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. Title insurance covering mineral leaseholds is not generally available and, in all instances, we forego the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease until the drilling block is assembled and ready to be drilled, except in Arkansas where we have commenced drilling without complete legal examination of title. As is customary in our industry, we rely upon the judgment of oil and natural gas lease brokers, in-house landmen or independent landmen who perform the field work in examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest. We do not always perform curative work to correct deficiencies in the marketability of the title to us. Except for our properties in Arkansas, we obtain title opinions for specific drilling locations prior to the commencement of drilling. In Arkansas, we have commenced drilling but are in the process of obtaining title opinions. In cases involving more serious title problems, the amount paid for affected oil and natural gas leases can be lost, and the target area can become undrillable. We may be subject to litigation from time to time as a result of title issues.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the regions where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas on federal lands, drilling and other oil and natural gas activities can only be conducted during limited times of the year. These restrictions limit our ability to operate in those areas and can potentially intensify competition for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

We depend on our senior management team and other key personnel. Accordingly, the loss of any of these individuals could adversely affect our business, financial condition, the results of operations and future growth.

Our success is largely dependent on the skills, experience and efforts of our people. The loss of the services of one or more members of our senior management team or of our other employees with critical skills needed to operate our business could have a negative effect on our business, financial condition, results of operations and future growth. We currently have employment agreements with our executive officers and other key employees. Our ability to manage our growth, if any, will require us to continue to train, motivate and manage our employees and to attract, motivate and retain additional qualified personnel. Competition for these types of personnel is intense, and we may not be successful in attracting, assimilating and retaining the personnel required to grow and operate our business profitably.

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

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and natural gas, we currently, and may in the future, enter into derivative arrangements, subject to certain limitations pursuant to our credit facility, for a portion of our oil and natural gas production, including collars and fixed-price swaps. We have not designated any of our derivative instruments as hedges for accounting purposes and record all derivative instruments on our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative arrangements also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received.

In particular, the counterparties on all of our commodity hedging arrangements are either BNP Paribas or Société Générale. Our risk of counterparty default may be impacted to the extent that these banks are exposed to losses as a result of the current European sovereign debt crisis or other future economic events.

In addition, these types of derivative arrangements limit the benefit we would receive from increases in the prices for oil and natural gas.

The recent adoption of derivatives legislation by the United States Congress 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.

The United States Congress recently adopted the Dodd-Frank Wall Street Reform and Consumer Protection Act, which includes comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. The new legislation was signed into law by the President on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the Securities and Exchange Commission (the "SEC") to promulgate rules and regulations implementing the new legislation within 360 days from the date of enactment. The CFTC has also proposed regulations to set position limits for certain futures and option contracts in the major energy markets, although it is not possible at this time to predict whether or when the CFTC will adopt those rules or include comparable provisions in its rulemaking under the new legislation. The financial reform legislation may also require us to comply with margin requirements and with certain clearing and trade-execution requirements in connection with its derivative activities. However, the application of those provisions to us is uncertain at this time. The financial reform legislation may also require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The new legislation and any new regulations could 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, reduce our ability to monetize or restructure existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the legislation and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the legislation 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 commodity prices decline as a consequence of the legislation and regulations. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Table of Contents

The credit default of one of our customers could have a temporary adverse effect on us.

Our revenues are generated under contracts with a limited number of customers. Our results of operations would be adversely affected as a result of non-performance by our two largest customers, which represent 47% and 39%, respectively, of our 2010 total revenues. A non-payment default by one of these large customers could have an adverse effect on us, temporarily reducing our cash flow.

Certain federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

On September 12, 2011, President Obama sent to Congress a legislative package that includes proposed legislation that, if enacted into law, would eliminate certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These proposals also were included in President Obama's Proposed Fiscal Year 2012 Budget. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. Recently, members of the U.S. Congress have considered similar changes to the existing federal income tax laws that affect oil and gas exploration and production companies, which, if enacted, would negatively affect our financial condition and results of operations. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could eliminate or defer certain tax deductions within the industry that are currently available with respect to oil and gas exploration and development, and any such change could negatively affect our financial condition and results of operations.

Our operations are subject to health, safety and environmental laws and regulations which may expose us to significant costs and liabilities.

Our oil and natural gas exploration, production and processing operations are subject to stringent and complex federal, state and local laws and regulations governing health and safety aspects of our operations, the discharge of materials into the environment and the protection of the environment. These laws and regulations may impose on our operations numerous requirements, including the obligation to obtain a permit before conducting drilling or underground injection activities; restrictions on the types, quantities and concentration of materials that may be released into the environment; limitations or prohibitions of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; specific health and safety criteria to protect workers; and the responsibility for cleaning up any pollution resulting from operations. Numerous governmental authorities such as the U.S. Environmental Protection Agency, or the EPA, and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, oftentimes requiring difficult and costly actions. Failure to comply with these laws and regulations may result in the assessment of administrative, civil or criminal penalties; the imposition of investigatory or remedial obligations; the issuance of injunctions limiting or preventing some or all of our operations; and delays in granting permits and cancellation of leases.

There is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of our wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we may be liable regardless of whether we were at fault for the full cost of removing or remediating contamination, even when multiple parties contributed to the release and the contaminants were released in compliance with all applicable laws. In addition, accidental spills or releases on our properties may expose us to significant liabilities that could have a material adverse effect on our financial condition or results of operations. Aside from government agencies, the owners of properties where our wells are located, the operators of facilities where our petroleum hydrocarbons or

Table of Contents

wastes are taken for reclamation or disposal and other private parties may be able to sue us to enforce compliance with environmental laws and regulations, collect penalties for violations or obtain damages for any related personal injury or property damage. Some sites we operate are located near current or former third-party oil and natural gas operations or facilities, and there is a risk that contamination has migrated from those sites to ours. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, emission, waste management or cleanup requirements could require us to make significant expenditures to attain and maintain compliance or may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition. We may not be able to recover some or any of these costs from insurance.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Our operations utilize hydraulic fracturing, an important and commonly used process in the completion of oil and natural gas wells in low-permeability formations. This process involves the injection of water, proppant and chemicals under pressure into rock formations to stimulate oil and natural gas production. Some activists have attempted to link fracturing to various environmental problems, including adverse effects to drinking water supplies as well as migration of methane and other hydrocarbons. As a result, several federal agencies are studying any environmental risk with respect to hydraulic fracturing or evaluating whether to restrict its use. Legislation has been introduced in the United States Congress called the Fracturing Responsibility and Awareness of Chemicals Act (the "FRAC Act") that would amend the federal Safe Drinking Water Act ("SDWA") to eliminate an existing exemption for hydraulic fracturing activities from the definition of "underground injection," thereby requiring the oil and natural gas industry to obtain permits for fracturing, and to require disclosure of the chemicals used in the process. If adopted, this legislation could establish an additional level of regulation and permitting at the federal level. At this time, it is not clear what action, if any, the United States Congress will take on the FRAC Act. Scrutiny of hydraulic fracturing activities continues in other ways, with the EPA having commenced a multi-year study of the potential environmental impacts of hydraulic fracturing, the initial results of which are anticipated to be available by late 2012. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The U.S. Department of the Interior has also announced its intention to propose a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water, which, if adopted, would affect our operations on federal lands. In addition to these federal initiatives, several state and local governments have moved to require disclosure of fracturing fluid components or otherwise to regulate their use more closely, including states in which we operate (Colorado, California and Arkansas). In certain areas of the country, new drilling permits for hydraulic fracturing have been put on hold pending development of additional standards. The adoption of any future federal, state or local laws or implementing regulations imposing permitting or reporting obligations on, or otherwise limiting, the hydraulic fracturing process could make it more difficult and more expensive to complete oil and natural gas wells in low-permeability formations and increase our costs of compliance and doing business, as well as delay or prevent the development of unconventional gas resources from shale formations which are not commercial without the use of hydraulic fracturing.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while the physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

There is a growing belief that emissions of greenhouse gases ("GHG") may be linked to climate change. Climate change and the costs that may be associated with its impacts and the regulation of GHG have the potential to affect our business in many ways, including negatively impacting the costs we incur in providing our products and services and the demand for and consumption of our products and services (due to change in both costs and weather patterns).

In December 2009, EPA determined that atmospheric concentrations of carbon dioxide, methane, and certain other GHG present an endangerment to public health and welfare because such gases are, according to EPA, contributing to the warming of the Earth's atmosphere and other climatic changes. Consistent with its findings, EPA has proposed or adopted various regulations under the Clean Air Act to address GHG. Among other things, the Agency is limiting emissions of GHG from new cars and light duty trucks beginning with the 2012 model year. In addition, EPA has published a final rule to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration, or "PSD," and Title V permitting programs, pursuant to which these permitting requirements have been "tailored" to apply to certain stationary sources of GHG emissions in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions will be required to meet emissions limits that are based on the "best available control technology," which will be established by the permitting agencies on a case-by-case basis. EPA has also adopted regulations requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including certain oil and natural gas production facilities, which include certain of our operations, beginning in 2012 for emissions occurring in 2011 and which may form the basis for further regulation. Many of EPA's GHG rules are subject to legal challenges, but have not been stayed pending judicial review. Depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules. EPA's GHG rules could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities.

Moreover, Congress has from time to time considered adopting legislation to reduce emissions of GHG or promote the use of renewable fuels. As an alternative, some proponents of GHG controls have advocated mandating a national "clean energy" standard. In 2011, President Obama encouraged Congress to adopt a goal of generating 80% of U.S. electricity from "clean energy" by 2035 with credit for renewable and nuclear power and partial credit for clean coal and "efficient natural gas"; the President also proposed ending tax breaks for the oil industry. Because of the lack of any comprehensive federal legislative program expressly addressing GHG, there currently is a great deal of uncertainty as to how and when additional federal regulation of GHG might take place and as to whether EPA should continue with its existing regulations in the absence of more specific Congressional direction.

In the meantime, many states, including California, already have taken such measures, which have included renewable energy standards, development of GHG emission inventories and/or cap and trade programs. Cap and trade programs typically work by requiring major sources of emissions or major producers of fuels to acquire and surrender emission allowances, with the number of available allowances reduced each year until the overall GHG emission reduction goal is achieved. These allowances would be expected to escalate significantly in cost over time. The adoption of legislation or regulatory programs to reduce emissions of GHG could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. If we are unable to recover or pass through a significant level of our costs related to complying with climate change regulatory requirements imposed on us, it could have a material adverse effect on our results of operations and financial condition. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHG could have an adverse effect on our business, financial condition and results of operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms and floods. If any such effects were to occur, they could have an adverse effect on our exploration and production operations. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Our insurance may not cover some or any of the damages, losses, or costs that may result from potential physical effects of climate change.

We will record substantial compensation expense in the financial quarter in which this offering occurs and we may incur substantial additional compensation expense related to our future grants of stock compensation which may have a material negative impact on our operating results for the foreseeable future.

As a result of outstanding stock-based compensation awards that vest upon consummation of this offering, we will incur substantial compensation expense at the close of this offering. In addition, our compensation expenses may increase in the future as compared to our historical expenses because of the costs associated with our existing and anticipated employee stock ownership and stock-based incentive plans. These additional expenses will adversely affect our net income. We cannot determine the actual amount of these new stock-related compensation and benefit expenses at this time because applicable accounting practices generally require that they be based on the fair market value of the options or shares of common stock at the date of the grant; however, we expect them to be significant. We will recognize expenses for our employee stock ownership plan when shares are committed to be released to participants' accounts and will recognize expenses for restricted stock awards and stock options generally over the vesting period of awards made to recipients.

Risks Related to this Offering and our Common Stock

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active liquid trading market for our common stock may not develop and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active and liquid trading market for our common stock may not develop or be maintained after this offering. Liquid and active trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between us and representatives of the underwriters, based on numerous factors which we discuss in the "*Underwriters; Conflicts of Interest*" section of this prospectus, and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in the offering.

The following factors could affect our stock price:

- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us or other stockholders, or the perception that such sales may occur;
- general market conditions, including fluctuations in commodity prices; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

Table of Contents

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Purchasers of common stock in this offering will experience immediate and substantial dilution of $3.82 per share.

Purchasers of our common stock in this offering will experience an immediate and substantial dilution of $3.82 per share in the pro forma net tangible book value per share of common stock from the initial public offering price, and our as adjusted pro forma net tangible book value as of September 30, 2011 after giving effect to this offering would be $13.18 per share. Our pro forma net tangible book value per share assumes the issuance of 437,787 shares of common stock upon conversion of our Class B Common Stock immediately prior to the consummation of this offering. If the underwriters exercise their over-allotment option in full, the dilution to purchasers of common stock in this offering would be $3.72 per share in pro forma net tangible book value, and our adjusted pro forma net tangible book value as of September 30, 2011 would be $13.28 per share. See "*Dilution*" for a complete description of the calculation of pro forma net tangible book value.

As a result of the reporting and disclosure requirements of a public company under the Exchange Act, the NYSE rules and the requirements of the Sarbanes-Oxley Act of 2002, we will incur significant additional costs and expenses and compliance with these requirements will require a substantial amount of management's time.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange, or the NYSE, with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;
- comply with rules promulgated by the NYSE;
- prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;
- hire additional accounting, finance and legal staff; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

In addition, we also expect that being a public company subject to these rules and regulations will increase our cost to obtain director and officer liability insurance coverage and could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers.

We do not intend to pay, and we are currently prohibited from paying, dividends on our common stock and, consequently, your only opportunity to achieve a return on your investment is if the price of our stock appreciates.

We do not plan to declare dividends on shares of our common stock in the foreseeable future. Additionally, we are currently prohibited from making any cash dividends pursuant to the terms of our

credit facility. Consequently, your only opportunity to achieve a return on your investment in us will be if the market price of our common stock appreciates, which may not occur, and you sell your shares at a profit. There is no guarantee that the price of our common stock that will prevail in the market after this offering will ever exceed the price that you pay.

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

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or convertible securities. After the completion of this offering, we will have 39,560,308 outstanding shares of common stock. This number includes 10,000,000 shares that we are selling in this offering, which may be resold immediately in the public market. Following the completion of this offering, Black Bear and certain clients of AIMCo will own 21,166,134 shares, or approximately 53.5% of our total outstanding shares. Each of Black Bear and certain clients of AIMCo is a party to a registration rights agreement with us. Pursuant to this agreement, subject to the terms of the lock-up agreement between each of Black Bear and certain clients of AIMCo and the underwriters described under the caption "*Underwriters; Conflicts of Interest*," we have agreed to effect the registration of shares held by Black Bear and certain clients of AIMCo if they so request or if we conduct other offerings of our common stock. See "*Certain Relationships and Related Party Transactions Registration Rights Agreement*." In addition, as soon as practicable after this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of additional shares of our common stock issued or reserved for issuance under our stock incentive and compensation plans. Shares registered under this registration statement on Form S-8 will be available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up agreements described above.

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

The equity trading markets may be volatile, which could result in losses for our stockholders.

In recent years, the stock market has experienced extreme price and volume fluctuations. This volatility has had a significant effect on the market price of securities issued by many companies for reasons unrelated to their operating performance. The market price of our common stock could similarly be subject to wide fluctuations in response to a number of factors, most of which we cannot control, including:

- domestic and worldwide supplies and prices of, and demand for, oil and gas;
- changes in environmental and other governmental regulations affecting the oil and gas industry;
- variations in our quarterly results of operations or cash flows; and
- changes in general conditions in the U.S. economy, financial markets or the oil and gas industry.

The realization of any of these risks and other factors beyond our control could cause the market price of our common stock to decline significantly.

Table of Contents

Our certificate of incorporation and bylaws contain, and Delaware law contains, provisions that may prevent, discourage or frustrate attempts to replace or remove our current management by our stockholders, even if such replacement or removal may be in our stockholders' best interests.

The effectiveness of our second amended and restated certificate of incorporation and bylaws is contingent upon this offering and will occur immediately after the conversion of our Class B Common Stock into Class A Common Stock and immediately prior to the consummation of this offering. Our second amended and restated certificate of incorporation and bylaws contain, and Delaware law contains, provisions that could enable our management to resist a takeover attempt. Among other things, our second amended and restated certificate of incorporation and bylaws will:

- establish advance notice procedures with regard to stockholder proposals relating to director nominations or new business to be brought before stockholder meetings. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our bylaws will specify the requirements as to form and content of all stockholder notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock and to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to gain control of us. These and other provisions may have the effect of deterring hostile takeovers or delaying changes in control or management of our company;

- provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. For more information on the classified board of directors, see "*Management*." This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;

- provide that the authorized number of directors may be changed only by resolution of the board of directors;

- provide that all vacancies, including newly created directorships, may, except as otherwise required by law, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum;

- provide that stockholders may only act at a duly called meeting and may not act by written consent in lieu of a meeting;

- provide that special meetings of stockholders may only be called by our board of directors, the Chairperson, the Chief Executive Officer or the President and not by our stockholders; and

- provide that our board of directors may alter or repeal our bylaws or approve new bylaws without further stockholder approval.

These provisions could:

- discourage, delay or prevent a change in the control of our company or a change in our management, even if the change would be in the best interests of our stockholders;

adversely affect the voting power of holders of common stock; and

limit the price that investors might be willing to pay in the future for shares of our common stock.

Table of Contents

West Face Capital and AIMCo together may be deemed to beneficially own or control a significant portion of our common stock, giving them a substantial influence over corporate transactions and other matters. Their interests and the interests of the parties on whose behalf they invest may conflict with yours, and the concentration of ownership of our common stock by such stockholders will limit the influence of public stockholders.

Upon completion of this offering, West Face Capital and AIMCo together may be deemed to beneficially own, control or have substantial influence over approximately 53.5% of our outstanding common stock, and approximately 51.5% if the underwriters exercise their option to purchase additional shares in full. West Face Capital and AIMCo, on behalf of certain of its clients, have entered into an investment management agreement pursuant to which West Face Capital has the right to vote the shares of our common stock held by certain clients of AIMCo. West Face Capital also has the right, pursuant to the advisory agreement with Black Bear, to vote the shares held by Black Bear, and accordingly, West Face Capital may exert significant influence over our board of directors and substantially influence the outcome of stockholder votes. Even if the investment management agreement between West Face and AIMCo were to be terminated, West Face Capital and AIMCo, on behalf of its clients, voting together as a group would have the ability to exert significant influence over the company. The investment management agreement with AIMCo may be terminated upon 90 days prior written notice or immediately in certain circumstances.

A concentration of ownership in West Face alone or together with AIMCo's clients would allow such stockholders to significantly influence, directly or indirectly and subject to applicable law, significant matters affecting us, including the following:

- establishment of business strategy and policies;
- amendment of our certificate of incorporation or bylaws;
- the payment of dividends on our common stock;
- nomination and election of directors;
- appointment and removal of officers;
- our capital structure; and
- compensation of directors, officers and employees and other employee-related matters.

Such a concentration of ownership may have the effect of delaying, deterring or preventing a change in control, a merger, consolidation, takeover or other business combination, and could discourage a potential acquirer from making a tender offer or otherwise attempting to obtain control of us, which could in turn have an adverse effect on the market price of our common stock.

The significant ownership interest of Black Bear and certain clients of AIMCo could also adversely affect investors' perceptions of our corporate governance. Further, because of the voting control exercised by West Face Capital, we will be considered a "controlled company" for purposes of the NYSE listing requirements. Although we do not currently intend to rely upon the exemptions to the NYSE's independence standards available for controlled companies, we may choose to do so in the future to the extent we remain a controlled company.

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information discussed in this prospectus include "forward-looking statements." These forward-looking statements are identified by their use of terms and phrases such as "may," "expect," "estimate," "project," "plan," "believe," "intend," "achievable," "anticipate," "will," "continue," "potential," "should," "could," and similar terms and phrases. All statements, other than statements of historical facts, included herein concerning, among other things, planned capital expenditures, potential increases in oil and natural gas production, the number of anticipated wells to be drilled after the date hereof, future cash flows and borrowings, pursuit of potential acquisition opportunities, our financial position, business strategy and other plans and objectives for future operations, are forward-looking statements. Although we believe that the expectations reflected in these forward-looking statements are reasonable, they do involve certain assumptions, risks and uncertainties. Our actual results could differ materially from those anticipated in these forward-looking statements as a result of certain factors, including, among others:

- our ability to replace oil and natural gas reserves;
- declines or volatility in the prices we receive for our oil and natural gas;
- our financial position;
- our cash flow and liquidity;
- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business;
- the recent economic slowdown that has and may continue to adversely affect consumption of oil and natural gas by businesses and consumers;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- uncertainties associated with estimates of proved oil and gas reserves and, in particular, probable and possible resources;
- the possibility that the industry may be subject to future regulatory or legislative actions (including additional taxes and changes in environmental regulation);
- environmental risks;
- drilling and operating risks;

exploration and development risks;

competition in the oil and natural gas industry;

management's ability to execute our plans to meet our goals;

our ability to retain key members of our senior management and key technical employees;

access to adequate gathering systems and pipeline take-away capacity to execute our drilling program;

our ability to secure firm transportation for oil and natural gas we produce and to sell the oil and natural gas at market prices;

costs associated with perfecting title for mineral rights in some of our properties;

- continued hostilities in the Middle East and other sustained military campaigns or acts of terrorism or sabotage; and

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our businesses, operations or pricing.

Finally, our future results will depend upon various other risks and uncertainties, including, but not limited to, those detailed in "*Risk Factors*." All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this prospectus and speak only as of the date of this prospectus. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

Table of Contents

USE OF PROCEEDS

We estimate that our net proceeds from the sale of common stock in this offering will be approximately $156.0 million, or $179.8 million if the underwriters exercise their over-allotment option in full, in each case after deducting estimated expenses and underwriting discounts and commissions. We intend to use a portion of the net proceeds from this offering to repay the outstanding indebtedness under our credit facility, which as of October 31, 2011, was approximately $149.1 million. We intend to use the remaining $6.9 million, or $30.7 million if the underwriters exercise their over-allotment option in full, of net proceeds from this offering, together with borrowings under our credit facility, to fund our drilling and development program and the expansion of our gas processing facilities. As of October 31, 2011, our cash and cash equivalents, as adjusted to give effect to this offering and the application of the net proceeds, was $12.0 million, or $35.8 million if the underwriters exercise their over-allotment option in full.

Our credit facility matures in September 2016 and bears interest at a variable rate, which was approximately 2.7% per annum as of October 31, 2011. Our outstanding borrowings under our credit facility were incurred to fund exploration, development and other capital expenditures.

Affiliates of certain of the underwriters are lenders and agents under our credit facility and, accordingly, will receive a portion of the net proceeds from this offering through the repayment of outstanding borrowings under the credit facility. See "*Underwriters; Conflicts of Interest*."

DIVIDEND POLICY

We do not expect to declare or pay any cash dividends in the foreseeable future on our common stock. Our credit facility currently prohibits us from paying cash dividends on our common stock, and we may enter into debt arrangements in the future that also prohibit or restrict our ability to declare or pay cash dividends on our common stock.

Table of Contents

CAPITALIZATION

The following table sets forth our capitalization, as of September 30, 2011:

- on an actual historical basis;
- on an as adjusted basis to give effect to the sale of shares by us in this offering and the application of the net proceeds as described in "*Use of Proceeds*."

You should read the following table in conjunction with "*Use of Proceeds*," "*Selected Historical Consolidated and Unaudited Pro Forma Financial Data*," "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and our historical financial statements and unaudited pro forma financial information and related notes thereto appearing elsewhere in this prospectus.

	As of September 30, 2011	
	Actual	As Adjusted
	(in thousands)	
Cash and cash equivalents[1]	$ 153	$ 24,003
Long-term debt:		
Credit facility[2]	$ 132,100	$
Total long-term debt	132,100	
Stockholders' equity:		
Common stock Class A, $0.001 par value; 99,990,000 shares authorized, 29,122,521 shares issued and outstanding	29	
Common stock Class B, $0.001 par value; 10,000 shares authorized, 6,600 shares issued and outstanding[3]		
Common stock, $0.001 par value; 250,000,000 shares authorized; 39,560,308 shares issued and outstanding[4]		39
Additional paid-in capital	356,582	512,522
Retained earnings	12,706	12,706
Total stockholders' equity	369,317	525,267
Total capitalization	$ 501,417	$ 525,267

(1) As of October 31, 2011, our cash and cash equivalents were $5.1 million.

(2) As of October 31, 2011, there was $149.1 million outstanding under our credit facility.

(3) Following the resignation of Steve Black, 6,000 shares were issued and outstanding. In connection with his employment with us, our board of directors approved a grant of 600 shares of our Class B Common Stock to James R. Casperson, our Chief Financial Officer.

(4) The as adjusted shares issued and outstanding includes 437,787 shares issued upon conversion of our Class B Common Stock immediately prior to the consummation of this offering.

Table of Contents

DILUTION

Purchasers of the common stock in this offering will experience immediate and substantial dilution in the net tangible book value per share of the common stock for accounting purposes. Our net tangible book value as of September 30, 2011 was approximately $365.6 million, or $12.55 per share of common stock. Pro forma net tangible book value per share is determined by dividing our pro forma tangible net worth (tangible assets less total liabilities) by the total number of outstanding shares of common stock that will be outstanding immediately prior to the closing of this offering including giving effect to the issuance of restricted stock awards at the closing of this offering. After giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting underwriting discounts and anticipated expenses of this offering), our adjusted pro forma net tangible book value as of September 30, 2011 would have been approximately $521.5 million, or $13.18 per share. This represents an immediate increase in the net tangible book value of $0.63 per share to our existing stockholders and an immediate dilution (*i.e.*, the difference between the offering price and the adjusted pro forma net tangible book value after this offering) to new investors purchasing shares in this offering of $3.82 per share. The following table illustrates the per share dilution to new investors purchasing shares in this offering:

Initial public offering price per share		$ 17.00
Pro forma net tangible book value per share as of September 30, 2011	$ 12.55	
Increase per share attributable to new investors in this offering	$ 0.63	
As adjusted pro forma net tangible book value per share after giving effect to this offering		$ 13.18
Dilution in pro forma net tangible book value per share to new investors in this offering		$ 3.82

If the underwriters exercise their over-allotment option in full, the dilution to purchasers of common stock in this offering would be $3.72 per share in pro forma net tangible book value, and our adjusted pro forma net tangible book value as of September 30, 2011 would be $13.28 per share.

The following table summarizes, on an adjusted pro forma basis as of September 30, 2011, the total number of shares of common stock owned by existing stockholders and to be owned by new investors, the total consideration paid, and the average price per share paid by our existing stockholders and to be paid by new investors in this offering, calculated before deduction of estimated underwriting discounts and commissions:

	Shares Acquired		Total Consideration		Average Price per Share
	Number	Percent	Amount (in thousands)	Percent	
Existing stockholders[(1)]	29,560,308	75%	$ 356,612	68%	$ 12.52
New investors	10,000,000	25	170,000	32	17.00
Total	39,560,308	100%	$ 526,612	100%	$ 13.31

(1) The number of shares disclosed for the existing stockholders includes 437,787 shares issued upon conversion of our Class B Common Stock immediately prior to the consummation of this offering.

If the underwriters exercise their over-allotment option in full, the number of shares held by the existing stockholders after this offering would be 29,560,308, or 72% of the total number of shares of our common stock outstanding after this offering, and the number of shares held by new investors would increase by 1,500,000 to 11,500,000, or 28% of the total number of shares of our common stock outstanding after this offering.

38

Table of Contents

SELECTED HISTORICAL CONSOLIDATED AND UNAUDITED PRO FORMA FINANCIAL DATA

The following tables set forth selected historical financial data of us and our predecessor, BCEC, as of and for the periods indicated. The consolidated statement of operations data for the years ended December 31, 2008, 2009 and the period ended December 23, 2010 are derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated statements of operations data for December 31, 2006 and 2007 is derived from audited consolidated financial statements of BCEC not included in this prospectus. The consolidated balance sheet data as of December 31, 2006, 2007 and 2008 are derived from the audited consolidated financial statements of BCEC, which are not included in this prospectus. The consolidated balance sheet data as of December 31, 2009 is derived from the audited consolidated financial statements of BCEC included elsewhere in this prospectus. The consolidated balance sheet data as of December 31, 2010 is derived from our audited consolidated financial statements included elsewhere in this prospectus. The consolidated statement of operations data for the period from inception (December 23, 2010) to December 31, 2010 and the nine months ended September 30, 2010 are derived from the financial statements of BCEC appearing elsewhere in this prospectus, and the consolidated statement of operations data for the nine months ended September 30, 2011 and the consolidated balance sheet data as of September 30, 2011 are derived from our unaudited financial statements appearing elsewhere in this prospectus, which, in management's opinion, include all adjustments necessary for the fair presentation of our financial condition as of such date and our results of operations for such periods.

The summary unaudited pro forma statement of operations of Bonanza Creek Energy, Inc. for the year ended December 31, 2010 gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The summary unaudited balance sheet of Bonanza Creek Energy, Inc. as of September 30, 2011 gives effect to this offering and the repayment of indebtedness as if they had occurred on September 30, 2011.

Table of Contents

The selected historical financial data should be read in conjunction with "*Management's Discussion and Analysis of Financial Condition and Results of Operations*" and both our and our predecessor's financial statements and the notes to those financial statements included elsewhere in this prospectus.

	Bonanza Creek Energy Company, LLC (Predecessor)						Bonanza Creek Energy, Inc.		Bonanza Creek Energy, Inc. Pro Forma[3]
	Inception to December 31, 2006[1]	**2007**	**2008**	**2009**	**Period Ended December 23, 2010[2]**	**Nine Months Ended September 30, 2010**	**Period from Inception (December 23, 2010) to December 31, 2010**	**Nine Months Ended September 30, 2011**	**Year Ended December 31, 2010**
						(unaudited)		**(unaudited)**	**(unaudited)**
	(in thousands, except per share data)								
Statement of Operations Data:									
Revenues:									
Oil sales	$ 4,142	$ 11,427	$ 39,967	$ 27,601	$ 34,431	$ 24,412	$ 1,325	$ 57,177	$ 45,413
Natural gas sales	1,113	1,736	5,165	3,671	6,226	4,807	207	9,283	10,253
Natural gas liquids and CO_2 sales	391	821	2,782	3,169	7,672	5,469	213	9,076	8,365
Total revenues	$ 5,646	$ 13,984	$ 47,914	$ 34,441	$ 48,329	$ 34,688	$ 1,745	$ 75,536	$ 64,031
Operating expenses:									
Lease operating	1,584	4,037	20,434	13,449	14,792	10,581	483	14,461	17,285
Severance and ad valorem taxes	325	577	1,847	2,148	1,621	1,055	70	3,860	2,524
Depreciation, depletion and amortization	1,796	4,237	25,463	14,108	14,225	11,554	506	21,083	20,917
General and administrative	2,096	4,752	7,477	7,610	8,375	6,289	323	9,116	9,338
Employee stock compensation[4]									
Exploration	40	65	25	131	361	202		573	380
Impairment of oil and gas properties[5]			26,437	579				4,067	
Cancelled private placement[6]					2,378	2,378			2,378
Total operating expenses	$ 5,841	$ 13,668	$ 81,683	$ 38,025	$ 41,752	$ 32,059	$ 1,382	$ 53,160	$ 52,822
Income (loss) from operations	(195)	316	(33,769)	(3,584)	6,577	2,629	363	22,376	11,209
Other income (expense):									
Interest expense	(2,483)	(5,748)	(12,870)	(16,582)	(18,001)	(13,494)	(58)	(2,687)	(1,263)
Amortization of debt discount		(1,684)	(5,987)	(7,963)	(8,862)	(6,556)			
Write off of deferred financing costs					(1,663)	(1,663)			(1,663)
Gain on sale of oil and gas properties	1,000		8	303	4,055	4,055			4,055
Unrealized gain (loss) in fair value of warrant put option[7]		(32,302)	70,972	(80,640)	34,345	23,672			

Unrealized gain (loss) in fair value of commodity derivatives	356	(925)	48,716	(34,589)	(7,605)	(2,523)	(514)	7,096	(8,119)
Realized gain (loss) on settled commodity derivatives		26	1,913	13,451	5,919	4,897	(47)	(2,353)	5,872
Other income (loss)	11	(43)	(229)	(179)	19	125		(100)	(47)
Total other income (expense)	(1,116)	(40,676)	102,523	(126,199)	8,207	8,513	(619)	1,956	(1,165)
Income (loss) before income taxes	(1,311)	(40,360)	68,754	(129,783)	14,784	11,142	(256)	24,332	10,044
Income tax benefit (expense)[8]							94	(11,464)	(3,696)
Net income (loss)	$ (1,311)	$ (40,360)	$ 68,754	$ (129,783)	$ 14,784	$ 11,142	$ (162)	$ 12,868	$ 6,348
Net income (loss) per common share[9]									
Basic							$ (0.01)	$ 0.44	
Diluted							$ (0.01)	$ 0.44	
Weighted average shares outstanding									
Basic							29,123	29,123	
Diluted							29,123	29,123	

(1) Our predecessor, BCEC, was formed on May 17, 2006.

(2) We completed our Corporate Restructuring on December 23, 2010.

Table of Contents

(3) The pro forma information above gives effect to our Corporate Restructuring as if it had occurred on January 1, 2010.

(4) We will recognize employee stock-based compensation expense immediately prior to the consummation of this offering. We also expect to have stock-based compensation expense for future awards. See "*Management's Discussion and Analysis of Financial Condition and Results of Operations Selected Factors and Trends Affecting Our Results of Operations Stock-based Employee Compensation Expenses.*"

(5) The impairment for the year ended 2008 resulted from a write-down of the carrying value of our oil and natural gas reserves due to depressed year-end oil and natural gas prices.

(6) Expenditures in connection with a cancelled private placement of our preferred stock.

(7) In connection with its purchase of our senior subordinated notes D.E. Shaw Synoptic Portfolios 5, L.L.C. received warrants to purchase equity interests in our predecessor. These warrants contained a put right exercisable beginning on May 17, 2014. The periods presented for our predecessor reflect the changes in the fair market value of that put option. The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(8) Our predecessor, BCEC, was a partnership for federal income tax purposes and, therefore, was not subject to entity-level taxation. Our pro forma results reflect our taxation as a subchapter "C" corporation at an estimated combined state and federal income tax rate of 36.8%.

(9) As a limited liability company, ownership interests in our predecessor were held as membership interest units rather than shares.

	Bonanza Creek Energy Company, LLC (Predecessor)				Bonanza Creek Energy, Inc.		
	Inception to December 31, 2006[1]	As of December 31, 2007	2008	2009	As of December 31, 2010	As of September 30, 2011 (unaudited)	As of September 30, 2011 As Adjusted[2] (unaudited)
	(in thousands)						
Balance Sheet Data:							
Cash and cash equivalents	$ 5,039	$	$ 4,088	$ 2,522	$	$ 153	$ 24,003
Property and equipment, net	52,103	89,646	195,280	188,367	496,582	596,454	596,454
Total assets	62,317	97,044	241,625	211,552	516,104	626,903	650,753
Long term debt, including current portion:							
Credit facility		27,274	107,000	99,000	55,400	132,100	
Senior subordinated notes, net of discount	39,447	51,561	75,499	92,442			
Second lien term loan[3]							
Subordinated unsecured note			10,000	10,799			
Warrant put options[4]	8,839	42,851	828	81,468			
Total members'/stockholders' equity (deficit)	6,794	(33,566)	35,988	(93,795)	356,380	369,317	525,267

Bonanza Creek Energy Company, LLC (Predecessor)						Bonanza Creek Energy, Inc.	
Inception to December 31, 2006[1]	Year Ended December 31, 2007	2008	2009	Period Ended December 23, 2010[5]	Nine Months Ended September 30, 2010 (unaudited)	Period from Inception (December 23, 2010) to December 31, 2010	Nine Months Ended September 30, 2011 (unaudited)

(in thousands)

Other Financial Data:								
Net cash provided by (used in) operating activities	$ 3,764	$ (561)	$ 11,128	$ 11,134	$ 22,759	$ 14,141	$ (1,633)	$ 37,333
Net cash provided by (used in) investing activities	(21,739)	(43,265)	(79,581)	(7,185)	(32,127)	(17,265)	(817)	(110,852)
Net cash provided by (used in) financing activities	23,014	38,787	72,541	(5,515)	9,297	(2,857)		73,671
Adjusted EBITDAX(6)	1,653	4,537	14,435	19,067	25,071	18,414	822	45,646

(1) Our predecessor, BCEC, was formed on May 17, 2006.

(2) As adjusted for this offering and the application of proceeds as described in "*Use of Proceeds*."

(3) Our $30 million second lien term loan was fully funded on May 7, 2010 and repaid in full in connection with our Corporate Restructuring.

(4) The warrants and aggregate warrant exercise price were exchanged for shares of our common stock in connection with our Corporate Restructuring.

(5) We completed our Corporate Restructuring on December 23, 2010.

(6) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to our net income (loss) and net cash provided by (used in) operating activities, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation Adjusted EBITDAX*" above.

Table of Contents

UNAUDITED PRO FORMA FINANCIAL INFORMATION

We were formed on December 23, 2010, in connection with our Corporate Restructuring. The following unaudited pro forma financial information shows the pro forma effect of our Corporate Restructuring. We have not included a pro forma balance sheet since the effects of our Corporate Restructuring are reflected in the December 31, 2010 balance sheet included elsewhere in this prospectus. The unaudited pro forma statement of operations for the year ended December 31, 2010 was prepared as if our Corporate Restructuring had occurred at January 1, 2010.

The accompanying financial information was from the historical accounting records. We made no additional pro forma adjustment to general and administrative expense since we were the operator of these properties prior to the acquisitions.

The following unaudited pro forma financial statements do not purport to represent what our actual results of operations would have been if this acquisition had occurred on January 1, 2010. The unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented included elsewhere in this prospectus.

Table of Contents

	Bonanza Creek Energy Company, LLC Period Ended December 23, 2010	Holmes Eastern Company, LLC Period Ended December 23, 2010	Bonanza Creek Energy, Inc. Period from Inception (December 23, 2010) to December 31, 2010	Pro Forma Adjustments (unaudited)	Bonanza Creek Energy, Inc. Year Ended December 31, 2010 (unaudited)
	(in thousands, except per share data)				
Revenues:					
Oil, natural gas, natural gas liquids and CO_2 sales	$ 48,328	$ 13,958	$ 1,745	$	$ 64,031
Operating expenses:					
Lease operating	14,792	2,010	483		17,285
Severance and ad valorem taxes	1,620	834	71		2,525
Exploration	361	19			380
Depreciation, depletion and amortization(1)	14,225	3,006	506	3,180	20,917
General and administrative	8,375	640	323		9,338
Cancelled private placement	2,378				2,378
Total operating expenses	41,751	6,509	1,383	3,180	52,822
Income from operations	6,577	7,449	362	(3,180)	11,209
Other income (expense):					
Gain on sale of oil and gas properties	4,055				4,055
Other income (loss)	19	(65)			(47)
Write off of deferred financing costs	(1,663)				(1,663)
Unrealized gain on fair value of warrant put option(2)	34,345			(34,345)	
Amortization of debt discount(3)	(8,862)			8,862	
Realized gain on settled commodity derivatives	5,919		(47)		5,872
Unrealized loss in fair value of commodity derivatives	(7,605)		(514)		(8,119)
Interest expense(4)	(18,001)	(439)	(57)	17,234	(1,263)
Total other income (expense)	8,207	(504)	(618)	(8,249)	(1,165)
Income (loss) before income taxes	$ 14,784	$ 6,945	$ (256)	$ (11,429)	$ 10,044
Pro forma income tax expense(5)					(3,696)

Net Income	$	6,348
Earnings per share basic and diluted		

(1) Pro forma depletion expense gives effect to our Corporate Restructuring which required the application of purchase accounting. The expense was calculated using estimated proved reserves as of the beginning of the period, production for the applicable period, and the fair value of the purchase price allocated to proved oil and gas properties.

(2) BCEC issued an aggregate of 33,089 warrants to purchase Class A units during 2006, 2007, and 2008 in connection with the sale of senior subordinated notes. These warrants included a one time right and option to put the warrants back to BCEC at fair market value less the exercise price. This pro forma adjustment reverses the mark-to-market income for the warrant put right that was recorded during 2010. This

Table of Contents

presentation assumes that the warrants were exercised on January 1, 2010 in connection with a recapitalization.

(3) During 2010, BCEC recorded accretion expense for the subordinated debt discount. This pro forma adjustment reverses the accretion expense recorded during 2010. This presentation assumes that the subordinated debt was paid off on January 1, 2010 in connection with a recapitalization.

(4) This pro forma adjustment reduces interest expense by $10.9 million for BCEC interest expense that was paid in kind during 2010, a further reduction to interest expense for the amortization of debt issuance costs related to BCEC's second lien term loan that was entered into during 2010, and a further reduction for cash interest expense paid on the revolving credit facilities of BCEC and HEC and BCEC's related party note payable during 2010. This presentation assumes that BCEC's subordinated debt, the second lien term loan and BCEC's related party note payable were paid off and the balance outstanding on our revolving credit facility was reduced on January 1, 2010 in connection with a recapitalization.

(5) Pro forma income taxes related to our pre-tax income for the year ended December 31, 2010 and is based on our expected tax rate of 36.8%.

Pro Forma Reserve Quantity and Standardized Measure Information

The following table sets forth certain unaudited pro forma information concerning our proved oil and gas reserves giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. The following estimates of proved oil and gas reserves, both developed and undeveloped, represent interests we acquired in our Corporate Restructuring, and are located solely within the United States. Proved reserves represent estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed oil and gas reserves are the quantities expected to be recovered through existing wells with existing equipment and operating methods. Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which relatively major expenditures are required for completion.

The estimate of proved reserves and related valuations for the period ended December 23, 2010 was based upon a report prepared by Cawley, Gillespie & Associates, Inc. Petroleum Consultants as of December 31, 2010, adjusted for eight days of operations. The estimates of proved reserves are inherently imprecise and are continually subject to revision based on production history, results of additional exploration and development, price changes and other factors. These estimates do not include probable or possible reserves. The information provided does not represent our estimate of expected future cash flows or value of proved oil and gas reserves.

Table of Contents

Changes in estimated reserve quantities:

	Oil (MBbl)			Natural Gas (MMcf)		
	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Balance December 31, 2009	15,270	6,118	21,388	27,610	16,565	44,175
Extensions and discoveries	1,258	50	1,308	2,249	228	2,477
Sales of minerals in place	(559)		(559)			
Production	(595)	(138)	(733)	(1,309)	(781)	(2,090)
Revisions to previous estimates	1,302	(308)	994	12,674	5,690	18,364
Balance December 23, 2010	16,676	5,722	22,398	41,224	21,702	62,926
Proved developed reserves:						
December 31, 2009	4,710	1,292	6,002	7,021	5,346	12,367
December 23, 2010	6,465	1,734	8,199	13,703	6,413	20,116
Proved undeveloped reserves:						
December 31, 2009	10,560	4,826	15,386	20,589	11,219	31,808
December 23, 2010	10,211	3,988	14,199	27,521	15,289	42,810

The following table sets forth unaudited pro forma information concerning the discounted future net cash flows from our proved oil and gas reserves as of December 23, 2010, net of income tax expense, and giving effect to our Corporate Restructuring as if it had occurred on January 1, 2010. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and natural gas reserves. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and natural gas properties.

Standardized measure of discounted future net cash flows from estimated production of proved oil and gas reserves as of December 23, 2010 (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Future cash flows	$ 1,366,948	$ 528,802	$ 1,895,750
Future production costs	(434,498)	(138,515)	(573,013)
Future development costs	(222,007)	(130,202)	(352,209)
Future income tax expense	(126,005)	(57,242)	(183,247)
Future net cash flows	584,438	202,843	787,281
10% annual discount for estimated timing of cash flows	(299,329)	(113,149)	(412,478)
Standardized measure of discounted future net cash flows	$ 285,109	$ 89,694	$ 374,803

Future cash flows as shown above were reported without consideration for the effects of derivative transactions outstanding at each period end.

Table of Contents

Changes in standardized measure of discounted future net cash flows from proved oil and gas reserves (in thousands):

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC	Pro Forma Combined
Beginning of period	$ 185,704	$ 58,150	$ 243,854
Sale of oil and gas produced, net of production costs	(31,916)	(11,113)	(43,029)
Net changes in prices and production costs	97,744	42,468	140,212
Extensions, discoveries and improved recoveries	17,405	590	17,995
Development costs incurred	21,615	9,342	30,957
Changes in estimated development cost	(30,350)	(14,006)	(44,356)
Sales of mineral in place	(10,799)		(10,799)
Revisions of previous quantity estimates	65,959	11,833	77,792
Net change in income taxes	(38,932)	(10,019)	(48,951)
Accretion of discount	20,368	7,183	27,551
Changes in production rates and other	(11,689)	(4,734)	(16,423)
End of period	$ 285,109	$ 89,694	$ 374,803

Average wellhead prices inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation as of December 23, 2010 were calculated using the first-day-of-the-month price for each of the 12 months that made up the reporting period.

	Bonanza Creek Energy Company, LLC	Holmes Eastern Company, LLC
Oil (per Bbl)	$ 74.77	$ 75.33
Gas (per Mcf)	$ 4.72	$ 4.98

Table of Contents

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with the selected historical financial data and the accompanying financial statements and the notes to those financial statements included elsewhere in this prospectus. The following discussion includes forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this prospectus, particularly in "*Risk Factors*" and "*Cautionary Note Regarding Forward-Looking Statements*."

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas, primarily in southern Arkansas and in the DJ and North Park Basins in the Rocky Mountains. We were incorporated as a Delaware corporation in December 2010 to acquire all of the outstanding membership interests of BCEOC pursuant to our Corporate Restructuring. For more information regarding our Corporate Restructuring, see " *Recent Developments*." Our primary business objective is to increase stockholder value by investing capital in projects that we expect will increase our production, reserves and cash flow through the exploitation and development of our existing properties while maintaining a low cost structure. In addition, we intend to pursue acquisitions of properties that are complementary to our target areas of operation.

Formed in May 2006, BCEC initially focused on exploiting and developing properties located in the DJ and North Park Basins in the Rocky Mountains and certain fields located in the San Joaquin Valley of central California. In 2008, BCEC expanded its operations by acquiring significant acreage and other properties in southern Arkansas. Following our Corporate Restructuring, we have been able to increase our reserves and production through the exploitation and development of our existing property base, together with pursuing opportunistic acquisitions in areas where we have specific operating expertise. We estimate we will spend $162.1 million in 2011 to drill 115 gross (107.3 net) wells, to perform workovers on 37 gross (30.9 net) wells and to make other improvements to our infrastructure, including the construction of an additional gas processing facility. As of October 31, 2011, we had drilled 109 gross (101.9 net) of these wells, including 36 gross (31.5 net) wells in southern Arkansas, 64 gross (63.0 net) vertical wells in the DJ Basin, 4 gross (3.8 net) horizontal Niobrara wells in the DJ Basin, 2 gross (2.0 net) wells in the North Park Basin and 3 gross (1.5 net) wells in California.

Recent Developments

Corporate Restructuring

On December 23, 2010, our predecessor, BCEC was recapitalized as part of our Corporate Restructuring, as a result of which we became the owner of all of the equity in BCEOC and HEC. Our Corporate Restructuring consisted of the following transactions:

- BCEC contributed all of its ownership interest in its wholly owned subsidiary BCEOC to us in exchange for 6,272,851 shares of our Class A common stock.

- In exchange for $265 million in cash, we sold shares of our Class A common stock ("Class A Common Stock") to Black Bear, an entity advised by West Face Capital, and to certain clients of AIMCo.

- The members of HEC contributed all of their outstanding membership interests in HEC to us in exchange for approximately $59 million in cash (including approximately $7.2 million in assumed debt repaid at closing) and 1,683,536 shares of our Class A Common Stock with a value equal to

Table of Contents

approximately $21 million, for a total purchase price of approximately $80 million, subject to certain adjustments.

Cash proceeds of approximately $182 million were used to retire BCEC's second lien term loan, senior subordinated notes, a related-party note payable and to reduce the outstanding principal balance under BCEC's credit facility by $29 million.

On April 1, 2011, BCEC was dissolved and the exchange of BCEC's equity for ownership of shares of our common stock held by BCEC was completed. As part of the liquidation of BCEC, (i) shares of our common stock were contributed by certain members of BCEC to Bonanza Creek Employee Holdings, LLC ("BCEH") and (ii) other shares of our common stock were redeemed into an investment trust for the benefit of Bonanza Creek Oil Company, LLC, certain of its members and certain of our employees. We assumed the remaining balance outstanding of approximately $55.4 million under the credit facility, which was repaid on March 29, 2011, from the proceeds of our credit facility.

The acquisition of HEC provided us with additional acreage and working interests in the DJ Basin in the Rocky Mountains and the Dorcheat Macedonia field in southern Arkansas. We believe the properties we acquired are synergistic to our operations. BCEC has operated the interests acquired since May 2009, which consist of acreage adjacent to our producing property base in southern Arkansas and the Rocky Mountains and additional working interests in our existing property base. The properties have associated net proved reserves of approximately 9,339 MBoe at December 23, 2010, of which 30% was developed.

New Senior Credit Agreement

On March 29, 2011, we entered into a four-year $300 million credit agreement with a syndicate of banks providing for a senior secured revolving credit facility with an initial borrowing base of $130 million and with a $5 million subfacility for standby letters of credit. As of December 2, 2011, the borrowing base under our credit facility is $220 million with a $15 million subfacility for standby letters of credit. For a description of the material terms of our credit facility see *"Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources Credit facility."*

Capital Expenditures

We intend to accelerate our production growth by further exploiting our existing proved reserve base in the Mid-Continent and proved and unproved reserves in the Rocky Mountains, including the properties we acquired as a result of the HEC acquisition. In addition, we expect to begin development of our extensive inventory of horizontal Niobrara oil shale potential located in Colorado.

Our total 2011 capital expenditure budget is approximately $162.1 million, exclusive of acquisitions, which consists of:

$141.3 million for development of our oil and gas properties; and

$20.8 million for the construction of an additional gas processing facility that was completed in September 2011 and for other miscellaneous capital expenditures.

We expect to drill 115 gross (107.3 net) wells in 2011, including 42 gross (36.9 net) infill PUD locations in southern Arkansas, 64 gross (63.0 net) vertical wells in the DJ Basin, 4 gross (3.8 net) horizontal Niobrara oil shale wells in the DJ Basin, 2 gross (2.0 net) vertical wells in the North Park Basin, and 3 gross (1.5 net) wells in California. As of October 31, 2011, we had drilled 109 gross (101.9 net) of these wells, including 36 gross (31.5 net) wells in southern Arkansas, 64 gross (63.0 net) vertical wells in the DJ Basin, 4 gross (3.8 net) horizontal Niobrara wells in the DJ Basin, 2 gross (2.0 net) wells in the North Park Basin and 3 gross (1.5 net) wells in California. While we estimate we will spend $141.3 million for the development of our oil and gas properties, the ultimate amount of capital we will spend during the remainder of 2011 depends on the success of our drilling results as the year progresses. To date, our 2011 capital budget has been funded from the proceeds of our Corporate Restructuring, borrowings under our credit facility and cash flow from operations.

To continue uninterrupted development of our oil and natural gas reserves in the Dorcheat Macedonia field, we spent $17.7 million to build a 12.5 MMcf/d processing facility in our Dorcheat Macedonia field. Construction was completed in September of this year. The construction of this new facility is in conjunction with our continued development of the field. Together with our McKamie facility, the facilities process all of the natural gas that we produce from the Dorcheat Macedonia and McKamie Patton fields.

We believe the net proceeds from this offering together with cash flows from operations and additional borrowings under our credit facility will be sufficient to fund the remainder of our 2011 budgeted capital expenditures. When we deem appropriate, we enter into certain derivative arrangements with respect to portions of our oil and natural gas production to allow us to achieve a more predictable cash flow and to reduce some of our exposure to commodity price fluctuations.

We recently approved our 2012 capital expenditure budget, pursuant to which we expect to spend approximately $250 million to continue developing our oil and gas properties across our regions and to expand our gas processing facilities in southern Arkansas.

Selected Factors and Trends Affecting Our Results of Operations

Revenues. Our revenues depend substantially upon oil and natural gas prices and demand for oil and natural gas. From January 1, 2008 through September 30, 2011, the WTI spot prices for crude oil ranged from a low of $39.40 per barrel to a high of $134.60 per barrel. Oil prices have increased significantly since the first six months of 2010. Our average unhedged sales price for crude oil for the first six months of 2011 was $93.44 per barrel, compared to $72.02 per barrel for the first six months of 2010, which price increase, along with a 91% increase in crude oil sales volumes, contributed to the 148% increase in our oil revenues in those periods.

Production Trends. Our production levels are heavily influenced by our acquisitions and development drilling, as well as the price of oil. In April 2008, we acquired significant producing properties in southern Arkansas. The full-year effect of production from these properties was the primary reason our sales volumes increased by 23% in 2009 compared with 2008. Our sales volumes increased another 14% in 2010 due primarily to development activities in the southern Arkansas and the Rocky Mountains. Our production levels during the nine months ended September 30, 2011 have increased by 79% compared to the nine months ended September 30, 2010 as a result of the HEC acquisition. To further increase our production, we expect to spend approximately $162.1 million in 2011 to drill 115 gross (107.3 net) wells, to perform workovers on 37 gross (30.9 net) wells and to make other improvements to our infrastructure. Although the amount, timing and allocation of capital expenditures is largely discretionary and within our control, if oil and natural gas prices decline or costs increase significantly, we could defer a significant portion of our budget or expected capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Production Expenses. Our production expenses consist primarily of lease operating costs and severance and ad valorem taxes and are correlated to our level of production and oil prices. Our lease operating costs decreased by 35% from 2008 to 2009, primarily as a result of the reduction of steam injection in our California thermal properties as the price of oil dropped, which made production at these properties less economic. In response to increased oil prices beginning in July 2009, we resumed steam injection, which has resulted in higher production expenses. Our lease operating costs increased by 13%

Table of Contents

from 2009 to 2010, primarily as a result of a 14% increase in our sales volume, higher compression rental costs in our Dorcheat Macedonia field, higher expenditures for well workovers and increased steam injection expense related to our California thermal properties. Generally, as commodity prices and/or our production levels rise, our severance and ad valorem taxes increase.

General and Administrative Expenses. Our general and administrative expenses increased by $1.1 million, or 14%, from 2009 to 2010, a significant portion of which was attributable to aggregate bonus of $0.5 million received by employees in connection with our Corporate Restructuring. Our general and administrative expenses during the nine months ended September 30, 2011 have increased by 45% compared to the nine months ended September 30, 2010 as a result of the HEC acquisition in December 2010. We expect that the additional compliance and disclosure obligations as a public company will require us to implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance and legal staff, which will result in an estimated annual cost of $3.5 million. Additionally, we believe our general and administrative expenses will increase as a result of stock-based compensation obligations relating to future awards.

Stock-based Employee Compensation Expenses. We have distributed 243,945 shares of Class A Common Stock held by BCEH to our employees in connection with this offering. We expect to recognize an employee stock-based compensation expense of approximately $4.1 million as of the date of the grant of those shares. In addition, we have awarded 6,600 shares of Class B Common Stock and have distributed the remaining 3,400 shares of Class B Common Stock in connection with this offering. We expect to recognize employee stock compensation expense relating to these grants during the years ended December 31, 2011, 2012, 2013 and 2014 of approximately $0.1 million, $2.5 million, $2.5 million and $2.3 million, respectively, assuming no forfeitures.

Debt Service Obligations. We intend to use the net proceeds from this offering to repay outstanding indebtedness under our credit facility. As of September 30, 2011, we had approximately $132.1 million outstanding under our credit facility. To the extent we borrow additional amounts under our credit facility to fund our capital expenditures or make acquisitions, our debt service obligations will increase, which may require a substantial portion of our operating cash flow depending on our outstanding borrowings, oil and natural gas prices and results of operations.

Results of Operations

The following discussion is of our consolidated results of operations, financial condition and capital resources. You should read this discussion in conjunction with our Consolidated Financial Statements and the Notes thereto contained elsewhere in this prospectus. Comparative results of operations for the period indicated are discussed below.

Nine Months Ended September 30, 2011 Compared to Nine Months Ended September 30, 2010

Revenues

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 24,412	$ 57,177	$ 32,765	134 %
Natural gas sales	4,807	9,283	4,476	93 %
Natural gas liquids sales	4,963	8,828	3,865	78 %
CO_2 sales	506	248	(258)	(51)%
Product revenues	$ 34,688	$ 75,536	$ 40,848	118 %

Table of Contents

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Sales volumes:				
Crude oil (MBbls)	342.5	634.4	291.9	85%
Natural gas (MMcf)	969.1	1,822.8	853.7	88%
Natural gas liquids (MBbls)	91.8	128.8	37.0	40%
Crude oil equivalent (MBoe)[1]	595.8	1,067.0	471.2	79%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Average Sales Prices (before hedging)[1]:				
Crude oil (per Bbl)	$ 71.29	$ 90.13	$ 18.84	26%
Natural gas (per Mcf)	4.96	5.09	0.13	3%
Natural gas liquids (per Bbl)	54.09	68.56	14.47	27%
Crude oil equivalent (per Boe)[2]	57.38	70.57	13.19	23%

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Average Sales Prices (after hedging)[1]:				
Crude oil (per Bbl)	$ 73.34	$ 85.67	$ 12.33	17 %
Natural gas (per Mcf)	5.51	5.36	(0.15)	(3)%
Natural gas liquids (per Bbl)	54.09	68.56	14.47	27 %
Crude oil equivalent (per Boe)[2]	59.45	68.36	8.91	15 %

(1) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Revenues increased by 118%, to $75.5 million for the nine months ended September 30, 2011 compared to $34.7 million for the nine months ended September 30, 2010. Oil production increased 85% and natural gas production increased 93% during the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010. The most significant component of the increased production was related to the acquisition of HEC, which occurred on December 23, 2010. Our product revenues and production for the nine months ended September 30, 2010 excluded HEC revenues and production of $10.4 million and 201.1 Mboe, respectively. The increase in net revenues was also the result of a 26% increase in oil prices with a 3% increase in natural gas prices, respectively, for an overall increase of 23% per Boe. Also contributing to the increased revenue was the increased production attributable to our drilling program.

Table of Contents

Operating Expenses

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 10,581	$ 14,461	$ 3,880	37%
Severance and ad valorem taxes	1,055	3,860	2,805	266%
General and administrative	6,289	9,116	2,827	45%
Depreciation, depletion and amortization	11,554	21,083	9,529	82%
Exploration	202	573	371	184%
Operating expenses	$ 29,681	$ 49,093	$ 19,412	65%

	Nine Months Ended September 30,			
	2010	2011	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 17.76	$ 13.55	$ (4.21)	(24)%
Severance and ad valorem taxes	1.77	3.62	1.85	105 %
General and administrative	10.56	8.54	(2.02)	(19)%
Depreciation, depletion and amortization	19.40	19.76	0.36	2 %
Exploration	0.34	0.54	0.20	59 %
Operating expenses	$ 49.83	$ 46.01	$ (3.82)	(8)%

Lease operating expenses. Our lease operating expenses increased $3.9 million, or 37%, to $14.5 million in the first nine months of 2011 from $10.6 million in the first nine months of 2010 and decreased on an equivalent basis from $17.76 per Boe to $13.55 per Boe. The increase in lease operating expense was related to increased production volumes due to the acquisition of HEC on December 23, 2010. The nine months ended September 30, 2010 does not include HEC lease operating expenses, which were $1.5 million. During the nine months ended September 30, 2011, gauging and pumping, well servicing and testing, and compressor rentals were $1.4 million, $1.2 million, and $0.7 million higher, respectively, than the nine months ended September 30, 2010. The decrease in lease operating expenses on an equivalent basis was primarily related to the lower operating costs of the wells acquired from HEC. On an equivalent basis, the lease operating expense for the wells acquired from HEC was $7.39 per Boe during the nine months ended September 30, 2010 as compared to the lease operating expense for BCEC's wells which was $17.76 per Boe during the nine months ended September 30, 2010.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $2.8 million, or 266%, to $3.9 million in the first nine months of 2011 from $1.1 million in the first nine months of 2010 and increased on a Boe basis from $1.77 to $3.62. The increase was primarily related to a 79% increase in production volumes and a 23% increase in realized prices per Boe during the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010, and an increase in ad valorem tax of $1.3 million due to higher assessment values. The nine months ended September 30, 2010 does not include HEC severance and ad valorem tax, which were $0.6 million. The increase in severance and ad valorem taxes on a Boe basis for the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010 was primarily related to higher ad valorem taxes of $1.3 million and true-ups of estimated severance taxes based on Colorado severance tax returns for 2009 and 2010 that were filed during April of the subsequent year. The revision of estimated severance taxes based on the final Colorado severance tax returns resulted in a decrease in severance tax expense in 2010 and an increase in severance tax expense in 2011.

Table of Contents

General and administrative. Our general and administrative expense increased $2.8 million, or 45%, to $9.1 million in the first nine months of 2011 from $6.3 million in the first nine months of 2010. The nine months ended September 30, 2010 does not include HEC's general and administrative expenses, which were $0.5 million. During the nine month period ended September 30, 2011, wages and benefits, legal and professional services fees, travel and lodging, and business development were $1.3 million, $1.1 million, $0.2 million, and $0.1 million, respectively, higher than the previous period. The increase in wages and benefits is related to increased head count and $0.9 million of increase in legal and professional services fees were related to investigations and transactions not consummated. The decrease in general and administrative expenses on an equivalent basis was primarily related to the acquisition of HEC, which added significant production without adding a commensurate amount of general and administrative expenses.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $9.5 million, or 82%, to $21.1 million in the nine months ended September 30, 2011 from $11.6 million in the nine months ended September 30, 2010. This increase was the result of a 79% increase in production and the step up in basis that was recorded in oil and gas properties as a result of our Corporate Restructuring. In connection with our Corporate Restructuring, all of our oil and gas fields were adjusted to fair value based on each field's discounted future net cash flows, which resulted in basis increases to the Mid Continent and Rocky Mountain fields with corresponding decreases to the California fields. Our depreciation, depletion and amortization expense per Boe increased by $0.36, or 2%, to $19.76 for the nine months ended September 30, 2011 as compared to $19.40 for the nine months ended September 30, 2010.

Exploration. Our exploration expense increased $0.4 million, or 184%, to $0.6 million in the nine months ended September 30, 2011 from $0.2 million in the nine months ended September 30, 2010. The increase in exploration expense was primarily related to the acquisition of 7,700 acres of 3-D seismic data on the eastern edge of the Wattenberg field in Weld County, Colorado to help evaluate our Niobrara oil shale acreage.

Impairment of Proved Properties. The Company recorded $3.5 million of proved property impairments on the Company's legacy California assets and $0.6 million of proved property impairment in one non-core field in Southern Arkansas for the nine months ended September 30, 2011. The impairments of the Company's legacy assets in California were related to steam flooding results that were lower than expected and the impairment of the non-core field in Southern Arkansas was related to the loss of a lease. There were no impairments of proved properties for the nine months ended September 30, 2010.

Other Income and Expense

Interest expense. Our interest expense decreased $10.8 million, or 80%, to $2.7 million in the nine months ended September 30, 2011 from $13.5 million in the nine months ended September 30, 2010. The decrease resulted from the application of $182 million of cash proceeds from our Corporate Restructuring to repay the second lien term loan, the senior subordinated notes and a related party note payable, and to repay $29 million of principal under our credit facility on December 23, 2010. Average debt outstanding for the nine months ended September 30, 2011 was $81.5 million as compared to $209.4 million for the nine months ended September 30, 2010.

Gain on sale of oil and gas properties. Our gain on sale of oil and gas properties decreased $4.1 million to no gain in the nine months ended September 30, 2011 from $4.1 million in the nine months ended September 30, 2010. In March 2010, we sold our non-operated working interest in the Jasmin, California property resulting in a gain on sale of $ 4.1 million.

Realized gain (loss) on settled commodity derivatives. Realized gains on oil and gas hedging activities decreased by $7.3 million from a gain of $4.9 million for the nine months ended September 30, 2010 to a loss of $2.4 million for the nine months ended September 30, 2011. Because we assumed a derivative in a liability position in 2008, our realized gain was higher by $3.7 million upon the settlement of this portion of the assumed derivative in the nine months ended September 30, 2010. The decrease from a realized cash hedge gain to a loss period over period was primarily related to commodity prices that were 23% higher during the nine months ended September 30, 2011 as compared to the nine months ended September 30, 2010.

Income Tax Expense. Our predecessor, BCEC, was not subject to federal and state income taxes. As a result of our Corporate Restructuring, we were organized as a Delaware corporation subject to federal and state income taxes. During the nine months ended September 30, 2011, the estimated effective tax rate was revised to reflect significant capital expenditures in Arkansas during 2011 that increased the effective tax rate from 36.87% to 38.04%. The higher effective tax rate was applied to the January 1, 2011 deferred income tax liability increasing the net deferred tax liability and deferred income tax expense by $2.2 million for the nine months ended September 30, 2011, which resulted in a total deferred income tax expense in our consolidated statement of operations of $11.5 million. We are allowed to deduct various items for tax reporting purposes that are capitalized for purposes of financial statement presentation. All income taxes for the period ended September 30, 2011 were deferred.

Change in fair value of warrant put option. The fair value of the warrant put option decreased $23.7 million, or 100%, to $0 for the nine months ended September 30, 2011 from a gain of $23.7 million for the nine months ended September 30, 2010. The decrease resulted from the exercise of the warrants on December 23, 2010 in connection with our Corporate Restructuring.

Amortization of debt discount. Our expense for amortization of debt discount decreased $6.6 million, or 100%, to $0 for the nine months ended September 30, 2011 from $6.6 million for the nine months ended September 30, 2010. The decrease resulted from the retirement of BCEC's senior subordinated notes on December 23, 2010 in connection with our Corporate Restructuring.

Eight Day Period Ended December 31, 2010

We completed our Corporate Restructuring on December 23, 2010. The operating results of BCEI for the eight-day period from December 24, 2010 through December 31, 2010 were net revenues, operating expenses, and income from operations of approximately $1.7 million, $1.4 million, and $0.4 million, respectively, and did not include transactions that were inconsistent or unusual when compared to the results for the audited period ended December 23, 2010. Other expense during this period was primarily comprised of a $0.5 million unrealized loss in the fair value of commodity derivatives.

Period Ended December 23, 2010 Compared to Year Ended December 31, 2009

We completed our Corporate Restructuring on December 23, 2010. The operating results presented below for the audited period ended December 23, 2010 exclude the audited eight-day period from December 24, 2010 through December 31, 2010.

Table of Contents

Revenues

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 27,601	$ 34,431	$ 6,830	25%
Natural gas sales	3,671	6,226	2,555	70%
Natural gas liquids sales	2,886	7,088	4,202	146%
CO_2 sales	283	583	300	106%
Product revenues	$ 34,441	$ 48,328	$ 13,887	40%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Sales Volumes:				
Crude oil (MBbls)	507.4	469.0	(38.4)	(8)%
Natural gas (MMcf)	939.0	1,308.5	369.5	39 %
Natural gas liquids (MBbls)	69.1	126.5	57.4	83 %
Crude oil equivalent (MBoe)(1)	733.0	813.6	80.6	11 %

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (before hedging)[1]:				
Crude oil (per Bbl)	$ 54.40	$ 73.41	$ 19.01	35%
Natural gas (per Mcf)	3.91	4.76	0.85	22%
Natural gas liquids (per Bbl)	41.77	56.04	14.27	34%
Crude oil equivalent (per Boe)[2]	46.60	58.69	12.09	26%

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Average Sales Prices (after hedging)[1]:				
Crude oil (per Bbl)	$ 67.40	$ 75.07	$ 7.67	11%
Natural gas (per Mcf)	5.05	5.01	(0.04)	(1)%
Natural gas liquids (per Bbl)	41.77	56.04	14.27	34%
Crude oil equivalent (per Boe)[2]	57.07	60.05	2.98	5%

(1)

Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Product revenues increased by 40%, to $48 million in 2010 compared to $34 million in 2009. The increase in product revenues was primarily due to higher average prices for oil, natural gas and natural gas liquids in 2010 as compared to 2009 of 35%, 22% and 34%, respectively, and higher natural gas and

Table of Contents

natural gas liquids production in 2010 as compared to 2009 of 39% and 83%, respectively. Production increases for natural gas and natural gas liquids were due primarily to 2010 development activities on our properties in southern Arkansas and Colorado. During 2010, we drilled 51 net wells as compared to 2.5 net wells drilled in 2009. Furthermore, our McKamie gas plant in Arkansas processed natural gas for HEC in 2009 and 2010 and we recognized natural gas and natural gas liquids volumes and revenues earned under a processing agreement. Natural gas and natural gas liquid volumes and revenues increased as HEC drilled 12 wells in 2010 as compared to 4 wells in 2009. Oil production decreased by 4% in 2010 as compared to 2009 primarily due to low drilling in 2009 and early 2010 resulting in a continued rate of decline for oil production from existing wells, partially offset by increased drilling activity in the later part of 2010.

Operating Expenses

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 13,449	$ 14,792	$ 1,343	10 %
Severance and ad valorem taxes	2,148	1,620	(528)	(25)%
General and administrative	7,610	8,375	765	10 %
Depreciation, depletion and amortization	14,108	14,225	117	1 %
Exploration	131	361	230	176 %
Impairment of oil and gas properties	579		(579)	(100)%
Cancelled private placement		2,378	2,378	100 %
Operating expenses	$ 38,025	$ 41,751	$ 3,726	10 %

	Year Ended December 31, 2009	Period Ended December 23, 2010	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 18.35	$ 18.18	$ (.17)	(1)%
Severance and ad valorem taxes	2.93	1.99	(.94)	(32)%
General and administrative	10.38	10.30	(.08)	%
Depreciation, depletion and amortization	19.25	17.49	(1.76)	(9)%
Exploration	0.18	0.44	0.26	144 %
Impairment of oil and gas properties	0.79		(.79)	(100)%
Cancelled private placement		2.92	2.92	100 %
Operating expenses	$ 51.88	$ 51.32	$ (0.56)	(1)%

Lease operating expenses. Our lease operating expenses increased $1.3 million, or 10%, to $14.8 million in 2010 from $13.4 million in 2009. The increase in lease operating expenses was primarily related to higher compression rental costs in our Dorcheat Macedonia field, increased workover activity and higher steam injection expense related to our California thermal properties.

Severance and ad valorem taxes. Severance and ad valorem taxes per Boe decreased by $0.94, or 32%, to $1.99 for 2010 from $2.93 for 2009. The decrease in production taxes was due primarily to refunds received from Colorado for overpayment of severance taxes in 2008 and 2009.

General and administrative. Our general and administrative expenses increased $0.8 million, or 10%, to $8.4 million for 2010 from $7.6 million for 2009. The increase in general and administrative expenses

Table of Contents

was due primarily to an aggregate bonus of $0.5 million awarded to employees in connection with our Corporate Restructuring in December 2010.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense increased $0.1 million, or 1%, to $14.2 million in 2010 from $14.1 million in 2009. Our depreciation, depletion and amortization expense per Boe produced decreased by $1.76, or 9%, to $17.49 for 2010 as compared to $19.25 for 2009 due primarily to additional reserves resulting from higher commodity prices in 2010 and reserves adds from workover and behind-pipe activities.

Other Income and Expense

Interest expense. Our interest expense increased $1.4 million, or 8%, to $18.0 million in 2010 from $16.6 million in 2009. As a result of $30 million in borrowings on a second lien note at a 14% rate, we paid down our first lien revolver at an annual rate of approximately 4%.

Gain on sale of oil and gas properties. Our gain on sale of oil and gas properties increased $3.8 million to $4.1 million in 2010 from $0.3 million in 2009. In March 2010, we sold our non-operated working interest in the Jasmin, California property resulting in a gain on sale of $ 4.1 million.

Realized gain on settled commodity derivatives. Our realized gain on settled commodity derivatives decreased $7.6 million, or 56%, to $5.9 million in 2010 from $13.5 million in 2009. The change was primarily related to higher commodity prices during 2010 that lowered our realized gain.

Cancelled private placement. During 2010, we incurred expenditures of $2.4 million in connection with our efforts to sell preferred stock through a private placement offering. Cost incurred is comprised primarily of legal fees, printing cost, travel and audit fees. The offering was cancelled in August 2010.

Change in fair value of warrant put option. The unrealized gain from the change in the fair value of the warrant put option increased $115 million to a gain of $34.3 million for 2010, as compared to a $80.6 million loss for the period ended December 31. 2009. This gain of $34.3 million resulted from a decrease in the value of the warrant put option from $81.5 million as of December 31, 2009 to $47.1 million as of December 23, 2010. The warrant was exercised for Class A units of BCEC and subsequently redeemed for shares of our Class A Common Stock in connection with our Corporate Restructuring and, therefore, no exercise occurred after December 23, 2010.

Accretion of debt discount. Our expense for accretion of debt discount increased $0.9 million, or 11%, to $8.9 million for the year ended December 31, 2010. The accretion expense is related to the amortization of our debt discount for the Series A, Series B and Series C Senior Subordinated Unsecured Notes.

Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Revenues

	Year Ended December 31,			
	2008	2009	Change	Percent Change
	(In thousands, except percentages)			
Revenues:				
Crude oil sales	$ 39,967	$ 27,601	$ (12,366)	(31)%
Natural gas sales	5,165	3,671	(1,494)	(29)%
Natural gas liquids sales	2,038	2,886	848	42%
CO_2 sales	744	283	(461)	(62)%
Product revenues	$ 47,914	$ 34,441	$ (13,473)	(28)%

Table of Contents

	Year Ended December 31, 2008	2009	Change	Percent Change
Sales Volumes:				
Crude oil (MBbls)	453.7	507.4	53.7	12%
Natural gas (MMcf)	668.9	939.0	270.1	40%
Natural gas liquids (MBbls)	35.5	69.1	33.6	95%
Crude oil equivalent (MBoe)[1]	600.7	733.0	132.3	22%

(1) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

	Year Ended December 31, 2008	2009	Change	Percent Change
Average Sales Prices (before hedging)[1]:				
Crude oil (per Bbl)	$ 88.09	$ 54.40	$ (33.69)	(38)%
Natural gas (per Mcf)	7.72	3.91	(3.81)	(49)%
Natural gas liquids (per Bbl)	57.45	41.77	(15.68)	(27)%
Crude oil equivalent (per Boe)[2]	78.53	46.60	(31.93)	(41)%

	Year Ended December 31, 2008	2009	Change	Percent Change
Average Sales Prices (after hedging)[1]:				
Crude oil (per Bbl)	$ 79.59	$ 67.40	$ (12.19)	(15)%
Natural gas (per Mcf)	7.93	5.05	(2.88)	(36)%
Natural gas liquids (per Bbl)	57.45	41.77	(15.68)	(27)%
Crude oil equivalent (per Boe)[2]	72.35	57.07	(15.28)	(21)%

(1) Although we do not designate our derivatives as cash flow hedges for financial statement purposes, the derivatives do economically hedge the price we receive for crude oil and natural gas.

(2) Determined using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil. Excludes CO_2 sales.

Revenues decreased by 28%, to $34 million, in 2009 compared to $48 million in 2008. The decrease in net revenues was primarily due to significantly lower average oil and natural gas prices in 2009. The 42% increase in natural gas liquids revenues was the result of increased volumes of natural gas liquids as a result of our acquisition of producing properties in southern Arkansas in April 2008. For 2009, sales volumes increased approximately 23% compared to 2008. The increase in sales volumes was primarily due to our acquisition of producing properties in southern Arkansas in April 2008 and the increase in drilling activity subsequent to the acquisition.

Table of Contents

Operating Expenses

	Year Ended December 31,			
	2008	2009	Change	Percent Change
	(In thousands, except percentages)			
Expenses:				
Lease operating	$ 20,435	$ 13,449	$ (6,986)	(34)%
Severance and ad valorem taxes	1,847	2,148	301	16 %
General and administrative	7,477	7,610	133	2 %
Depreciation, depletion and amortization	25,463	14,108	(11,355)	(45)%
Exploration	25	131	106	424 %
Impairment of oil and gas properties	26,437	579	(25,858)	(98)%
Operating expenses	$ 81,684	$ 38,025	$ (43,659)	(53)%

	Year Ended December 31,			
	2008	2009	Change	Percent Change
Selected Costs ($ per Boe):				
Lease operating	$ 34.02	$ 18.35	$ (15.67)	(46)%
Severance and ad valorem taxes	3.07	2.93	(.14)	(5)%
General and administrative	12.45	10.38	(2.07)	(17)%
Depreciation, depletion and amortization	42.39	19.25	(23.14)	(55)%
Exploration	0.04	0.18	0.14	350 %
Impairment of oil and gas properties	44.01	0.79	(43.22)	(98)%
Operating expenses	$ 135.98	$ 51.88	$ (84.10)	(62)%

Lease operating expense. Our lease operating expenses decreased $7.0 million, or 34%, to $13.4 million in 2009 from $20.4 million in 2008. The decrease in lease operating expenses was primarily related to the reduction of steam injection in our California thermal properties.

Severance and ad valorem taxes. Our severance and ad valorem taxes increased $0.3 million, or 16%, to $2.1 million in 2009 from $1.8 million in 2008. Severance and ad valorem taxes per Boe decreased $0.14, or 5%, to $2.93 for 2009 from $3.07 for 2008.

General and administrative. Our general and administrative expenses increased $0.1 million, or 2%, to $7.6 million for 2010 from $7.5 million for 2009.

Depreciation, depletion and amortization. Our depreciation, depletion and amortization expense decreased $11.4 million, or 45%, to $14.1 million in 2009 from $25.5 million in 2008. Our depreciation, depletion and amortization expense per Boe produced decreased by $23.14, or 55%, to $19.25 for 2009 as compared to $42.39 for 2008. The decrease was primarily due to a $26.4 million impairment we took on certain of our properties and accompanying reserve write-down, as a result of depressed oil and gas prices as of December 31, 2008.

Other Income and Expense

Interest expense. Our interest expense increased $3.7 million, or 29%, to $16.6 million in 2009 from $12.9 million in 2008. The increase was due to increased borrowings resulting primarily from the acquisition of producing properties in southern Arkansas.

Table of Contents

Change in fair value of warrant put option. The unrealized loss from the change in the fair value of the warrant put option increased $151.6 million to a loss of $80.6 million for the year ended December 31, 2009. The unrealized loss resulted from an increase in value of the warrant put option from $0.8 million as of December 31, 2008 to $81.5 million as of December 31, 2009.

Accretion of debt discount. Our expenses for accretion of debt discount increased $2.0 million, or 33%, to $8.0 million for the year ended December 31, 2009. The accretion expense is related to the amortization of our debt discount for the Series A, Series B and Series C Senior Subordinated Unsecured Notes.

Realized gain (loss) on settled commodity derivatives. Our realized gain on settled commodity derivatives increased $11.5 million to $13.5 million for the year ended December 31, 2009. The change was primarily related to lower commodity prices during 2009 that increased our realized gain.

Liquidity and Capital Resources

Our primary sources of liquidity to date have been proceeds from our Corporate Restructuring, capital contributions from investors, borrowings under our credit facility and cash flows from operations. Our primary use of capital has been for the acquisition and development of oil and natural gas properties.

On March 29, 2011, we entered into $300 million senior secured revolving credit facility to provide us with additional liquidity and flexibility for capital expenditures. As of October 31, 2011, we had $149.1 million of indebtedness outstanding. As of December 2, 2011, the borrowing base under our credit facility is $220 million. We intend to use a portion of the proceeds from this offering to pay down debt outstanding under our credit facility. The size of our borrowing base is at the discretion of the lenders under our credit facility and is dependent upon a number of factors, including commodity prices and reserve levels. For a summary of the material provisions of our credit facility, see " *Credit facility*."

We expect that in the future our commodity derivative positions will help us stabilize a portion of our expected cash flows from operations despite potential declines in the price of oil and natural gas. Please see " *Quantitative and Qualitative Disclosures on Market Risks.*"

We actively review acquisition opportunities on an ongoing basis. Our ability to make significant additional acquisitions for cash is dependent on our obtaining additional equity or debt financing, which we may not be able to obtain on terms acceptable to us or at all.

	Year Ended December 31,			Nine Months Ended September 30,	
	2008	2009	2010	2010	2011
			(in thousands)		
Financial Measures:					
Net cash provided by operating activities	$ 11,128	$ 11,134	$ 21,726	$ 14,141	$ 37,333
Net cash provided by (used in) investing activities	(79,581)	(7,185)	(32,944)	(17,265)	(110,852)
Net cash provided by (used in) financing activities	72,541	(5,515)	9,297	2,857	73,671
Cash and cash equivalents	4,088	2,522		2,255	153
Acquisitions of oil and gas properties	40,846	650	1,066	608	1,383
Exploration and development of oil and gas properties and gas processing facility	38,384	6,612	35,545	24,137	109,970

Table of Contents

Cash flows provided by operating activities

Net cash provided by operating activities was $37.3 million for the nine months ended September 30, 2011, compared to $14.1 million provided by operating activities for the nine months ended September 30, 2010. The increase in operating activities resulted primarily from an increase in revenues, increased production, and increased commodity prices offset by cash utilized in connection with changes in working capital when comparing the periods. Cash utilized by changes in working capital for the nine months ended September 30, 2011 was $5.8 million as compared to $2.3 million that was provided by changes in working capital for the comparable period during 2010. Decreases in working capital of $5.8 million for the nine months ended September 30, 2011 is comprised primarily of increases in accounts receivable of $6.1 million, offset by an increase in accounts payable and accrued expenses of $0.5 million. For the period ended September 30, 2010 the majority of the cash provided by operating activities was derived from an increase in accounts receivable of $2.7 million and an increase in accounts payable and accrued liabilities of $4.7 million.

Net cash provided by operating activities was $21.7 million, $11.1 million and $11.1 million for each of the years ended December 31, 2010, 2009 and 2008, respectively. Cash provided by changes in working capital for the year ended December 31, 2010 was $4.2 million as compared to cash that was utilized by changes in working capital in the amount of $2.8 million for the year ended December 31, 2009. Cash provided by changes in working capital for the year ended December 31, 2008 was $1.8 million. Increases in working capital of $4.2 million during 2010 is due primarily to an increase in trade payables and accrued expenses (exclusive of capital accruals) of $6.6 million, partially offset by an increase in trade receivables of $2.4 million, which changes are related to higher levels of activity in 2010.

Cash flows provided by (used in) investing activities

Expenditures for development of oil and natural gas properties and natural gas plants are the primary use of our capital resources. Net cash used in investing activities for the nine months ended September 30, 2011 was $110.9 million, compared to $17.3 million cash used in investing activities for the nine months ended September 30, 2010. Net cash used for the development of oil and natural gas properties was $110 million including expenditures of $18.1 million for a natural gas plant and other facilities. For the nine months ended September 30, 2010 expenditures for the development of oil and natural gas properties was $23.2 million offset by proceeds of $7.5 million for sale of our interest in the Jasmin field in California. For the year ended December 31, 2010, excluding our Corporate Restructuring, net cash used in investing activities was $32.9 million, of which we spent approximately $1.1 million on acquisitions, $35.5 million for the exploration and development of oil and gas properties, advanced $3.7 million to fund HEC's exploration and development program, offset by the receipt of proceeds in the amount of $7.5 million for the sale of the Jasmin field. In connection with our Corporate Restructuring, $59 million in cash along with common stock valued at $21.1 million was used to acquire HEC. For the year ended December 31, 2009, net cash used in investing activities was $7.2 million, of which we spent approximately $0.7 million for the acquisition of oil and gas properties and $6.6 million for the exploration and development of oil and gas properties. For the year ended December 31, 2008, net cash used in investing activities was $79.6 million, of which we spent approximately $41 million in cash on the acquisition of properties in southern Arkansas and the remainder on developing our proved reserves.

Cash flows provided by (used in) financing activities

Net cash flow provided by financing activities for the nine months ended September 30, 2011 was $73.7 million primarily related to net borrowings on our line of credit in the amount of $76.7 million offset by deferred financing costs of approximately $3 million. Net cash provided by financing activities for the nine months ended September 30, 2010 was $2.8 million and was primarily related to net borrowings on our revolving line net of payments on subordinated debt and $3.3 million of deferred financing costs. Net cash provided by financing, excluding Corporate Restructuring, was $9.3 million for the year ended

December 31, 2010, primarily related to net borrowings in the amount of $12.7 million offset by deferred financing charges in the amount of $3.4 million. Net cash used in financing activities was $5.5 million for the year ended December 31, 2009, primarily the result of making debt payments on our credit facility. Net cash provided by financing activities was $72.5 million for the year ended December 31, 2008 was primarily the result of increases in borrowings under our credit facility to fund development activities and issuing subordinated debt to acquire our properties in southern Arkansas.

In connection with our Corporate Restructuring, we received net proceeds of approximately $265 million from the sale of shares of our common stock to Black Bear, an entity advised by West Face Capital, and to certain clients of AIMCo. Proceeds from this transaction in the amount of $59 million along with common stock valued at $21.1 million was used to acquire HEC, $17.3 million of the proceeds were used for debt extinguishment penalties, and $182 million was used to retire the second lien term loan, the senior subordinated notes and a related party note payable, and to make a $29 million line of credit principal payment.

Credit facility

On March 29, 2011, we entered into a credit agreement providing for a $300 million senior secured revolving credit facility with an initial borrowing base of $130 million with a $5 million subfacility for standby letters of credit. On September 15, 2011, our borrowing base was increased to $180 million with a $15 million subfacility for standby letters of credit. On December 2, 2011, our borrowing base was further increased to $220 million. This credit facility is guaranteed by all of our subsidiaries.

Our borrowing base under our credit facility is redetermined semiannually on each April 1 and October 1 and may be redetermined up to one additional time between such scheduled determinations upon our request or upon the request of the required lenders (defined as lenders holding $66^2/_3$% of the aggregate commitments). The borrowing base is redetermined (i) in the sole discretion of the administrative agent and all of the lenders, (ii) in accordance with their customary internal standards and practices for valuing and redetermining the value of oil and gas properties in connection with reserve based oil and natural gas loan transactions, (iii) in conjunction with the most recent engineering report and other information received by the administrative agent and the lenders relating to our proved reserves and (iv) based upon the estimated value of our proved reserves as determined by the administrative agent and the lenders.

We intend to use the net proceeds from this offering to repay outstanding indebtedness under our credit facility, leaving us approximately $220 million available for future borrowings as of October 31, 2011. As of October 31, 2011, we had approximately $149.1 million outstanding under our credit facility. The credit facility matures on September 15, 2016. Amounts borrowed and repaid under the credit facility may be reborrowed. The credit facility may be used only to finance development of oil and gas properties, for working capital and for other general corporate purposes.

Our obligations under the credit facility are secured by first priority liens on all of our property and assets (whether real, personal, or mixed, tangible or intangible), including our proved reserves and our oil and gas properties (which term is defined to include fee mineral interests, term mineral interests, leases, subleases, farm-outs, royalties, overriding royalties, net profit interests, carried interests, production payments, back in interests and reversionary interests). The facility is guaranteed by us and all of our direct and indirect subsidiaries.

Interest under the credit facility is generally determined by reference to either, at our option:

- the London interbank offered rate, or LIBOR, for an elected interest period plus an applicable margin between 1.75% to 2.75%; or

Table of Contents

an alternate base rate (being the highest of the administrative agent's prime rate, the federal funds effective rate plus 0.5% or 3-month LIBOR plus 1.00%) plus an applicable margin between 0.75% and 1.75%.

The applicable margin varies on a daily basis based on the percentage outstanding under the borrowing base. We incur quarterly commitment fees based on the unused amount of the borrowing base ranging from 0.375% and 0.50% per annum. We may prepay loans under the credit facility at any time without premium or penalty (other than customary LIBOR breakage costs).

The credit facility contains various covenants limiting our ability to:

- grant or assume liens;
- incur or assume indebtedness;
- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;
- sell, transfer, assign or convey assets, or engage in certain mergers or acquisitions;
- make certain distributions;
- make certain loans, advances and investments;
- engage in transactions with affiliates;
- enter into sale and leaseback, take-or-pay or hydrocarbon prepayment transactions; or
- enter into certain swap agreements.

The credit facility also contains covenants requiring us to maintain:

- a current ratio of not less than 1.0 to 1.0; and
- a debt to EBITDAX coverage ratio of not more than: 4.00 to 1.00 as of the quarter ending March 31, 2011 (using EBITDAX for the quarter then ended multiplied by four); 4.00 to 1.00 as of the quarter ending June 30, 2011 (using EBITDAX for the two quarters then ending multiplied by two); 4.00 to 1.00 as of the quarter ending September 30, 2011 (using EBITDAX for the three quarters then ending multiplied by $^4/_3$); and 4.00 to 1.00 as of the quarter ending December 31, 2011 and each quarter thereafter (using the trailing four-quarter EBITDAX).

As of the nine months ended September 30, 2011, we were in compliance with these ratios.

The credit agreement contains customary events of default, including:

- failure to pay any principal, interest, fees, expenses or other amounts when due;

- the failure of any representation or warranty to be materially true and correct when made;
- failure to observe any agreement, obligation or covenant in the credit agreement, subject to cure periods for certain failures;
- a cross-default for the payment of any other indebtedness of at least $2 million;
- bankruptcy or insolvency;
- judgments against us or our subsidiaries, in excess of $2 million, that are not stayed;
- certain ERISA events involving us or our subsidiaries; and
- a change in control (as defined in the credit agreement), including the ownership following this offering by a "person" or "group" (as defined under the Securities and Exchange Act of 1934, as amended, but excluding certain permitted stockholders) directly or indirectly, of more than 35% of our common stock.

Table of Contents

Future capital requirements

We believe that the proceeds from this offering and our internally generated cash flow combined with access to our credit facility will be sufficient to meet the liquidity requirements necessary to fund our daily operations, planned capital development and execute on our growth strategy and debt service requirements. Any decision regarding a future financing transaction, and our ability to complete such a transaction, will depend on prevailing market conditions and other factors. Our ability to continue to meet our liquidity requirements and execute on our growth strategy can be impacted by economic conditions outside of our control, such as the recent disruption in the capital and credit markets, as well as commodity price volatility, which could, among other things, lead to a decline in the borrowing base under our credit facility in connection with a borrowing base redetermination. In such case, we may be required to seek other sources of capital earlier than anticipated, although the restrictions in our credit agreements may impair our ability to access other sources of capital, and access to additional capital may not be available on terms acceptable to us or at all.

Contractual Obligations

We have the following contractual obligations and commitments as of September 30, 2011 (in thousands):

	Total	1 Year or Less	2-3 Years	4-5 Years	More Than 5 Years
Credit facility[1]	$ 132,100			$ 132,100	$
Operating leases[2]	2,114	434	895	785	
Asset retirement obligations[3]	6,449	400	400		5,649
	$ 140,663	$ 834	$ 1,295	$ 132,885	$ 5,649

(1) Amount excludes interest on our credit facility as both the amount borrowed and the applicable interest rate is variable. On March 29, 2011, we entered into a new credit agreement, which matures on March 29, 2015.

(2) See Note 7 to our consolidated financial statements for a description of operating leases.

(3) Amount represents our estimate of future retirement obligations on a discounted basis unless otherwise noted. Because these costs typically extend many years into the future, management prepares estimates and makes judgments that are subject to future revisions based upon numerous factors. The $0.4 million included in the one year or less category is not discounted and is included in accounts payable and accrued expenses as of September 30, 2011.

Summary of Estimated Capital Expenditures

The following table summarizes our historical 2010 and our estimated 2011 capital expenditures. Our historical 2010 capital expenditures include 2010 expenditures made by HEC, which was acquired in December 2010. We routinely monitor and adjust our estimated capital expenditures in response to changes in oil and natural gas prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside

Table of Contents

our control. See "*Risk Factors Risks Related to the Oil and Natural Gas Industry and Our Business*." We do not budget for acquisitions.

Operation	**Historical and Projected Capital Expenditures Years Ended December 31, 2010**	**2011**
	(dollars in thousands)	
Oil and gas property development	$ 44,576	$ 141,328
Gas processing facility and other	4,491	20,806
Total	$ 49,067	$ 162,134

We recently approved our 2012 capital expenditure budget, pursuant to which we expect to spend approximately $250 million to continue developing our oil and gas properties across our regions and to expand our gas processing facilities in southern Arkansas.

Off-Balance Sheet Arrangements

As of September 30, 2011, we had no material off-balance sheet arrangements. We have no plans to enter into any off-balance sheet arrangements in the foreseeable future.

Critical Accounting Policies

Our discussion and analysis of financial condition and results of operations are based upon the information reported in our consolidated financial statements, which have been prepared in accordance with GAAP. In many cases, the accounting treatment of particular transactions is specifically required by GAAP. The preparation of our financial statements requires us to make estimates and judgments that can affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of our financial statements. We analyze our estimates and judgments, including those related to oil and natural gas revenues, oil and gas properties, fair value of derivative instruments, contingencies and litigation, and base our estimates and judgments on historical experience and various other assumptions that we believe to be reasonable under the circumstances. Actual results may vary from our estimates. These significant accounting policies are detailed in Note 2 to our consolidated financial statements. We have outlined below certain of these policies as being of particular importance to the portrayal of our financial position and results of operations and which require the application of significant judgment or estimates by our management.

Consolidation and Reporting. Our consolidated financial statements include the accounts of us and our wholly owned subsidiaries, after elimination of all significant intercompany accounts, transactions and profits. Our management has evaluated our consolidation of variable interest entities in accordance with ASC 810, and has concluded that we have no variable interest entities.

Oil and Natural Gas Properties. We utilize the successful efforts method of accounting for our oil and natural gas properties. Under this method of accounting, costs to acquire the mineral interests in oil and natural gas properties, to drill and complete exploratory wells that find proved reserves, and to drill and complete development wells are capitalized when incurred. Costs to drill exploratory wells that do not find proved reserves, delay rentals and geological and geophysical costs are expensed as incurred, other than the costs used to determine a drill site location.

Oil and Natural Gas Reserve Quantities. Our most significant financial estimates are based on estimates of proved oil and natural gas reserves. Estimates of proved reserves are key components of our rate of recording depreciation, depletion and amortization. Numerous uncertainties are 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. Our reserves are estimated on an annual basis by independent petroleum engineers.

Asset Retirement Obligations. ASC 410, Asset Retirement and Environmental Obligations, addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. In general, our future asset retirement obligations relate to future costs associated with the plugging and abandonment of our oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recognized in the period in which it is incurred, discounted to its present value using our credit adjusted risk-free interest rate, and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Revisions to estimated retirement obligations will result in an adjustment to the related capitalized asset and corresponding liability. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Revenue Recognition. We recognize revenues from the sales of oil and natural gas when the products are sold and delivery to the purchaser has occurred. Any amounts due from purchasers of oil and natural gas are included in accounts receivable in our consolidated balance sheet.

At times, we may sell more or less than our entitled share of gas production. When this happens, we use the entitlement method of accounting for gas sales, based on our net revenue interest in production. Accordingly, revenue would be deferred for gas deliveries in excess of our net revenue interest, while revenue would be accrued for any undelivered volumes.

Derivative Instruments and Hedging Activities. ASC 815, Derivatives and Hedging, requires that all derivative instruments be recorded on the balance sheet as either assets or liabilities at their respective fair values. We utilize swaps and collars to reduce our exposure to unfavorable changes in oil and natural gas prices. We recognize all derivative instruments on a consolidated balance sheet as either an asset or liability based on fair value and recognize subsequent changes in fair value in earnings unless the derivative instrument qualifies as a hedge. The fair value of the derivative instruments is confirmed monthly by the counterparties to the agreement. Management believes that credit and performance risk with our counterparties is minimal.

We did not designate any of our currently outstanding derivative instruments as hedges for financial statement purposes.

Recently Issued Accounting Pronouncements

Fair Value. In January 2010, the FASB issued authoritative guidance to update certain disclosure requirements and added two new disclosure requirements related to fair value measurements. See Note 11 to our consolidated financial statements included in this prospectus for a more detailed discussion of these requirements. We do not expect the adoption of this new guidance to have a significant impact on our financial position, cash flows or results of operations.

Oil and Gas Reporting Requirements. In December 2008, the SEC released the final rule, "Modernization of Oil and Gas Reporting," which adopts revisions to the SEC's oil and gas reporting disclosure requirements. The disclosure requirements under this final rule require reporting of oil and gas reserves using the unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months rather than year-end prices, and the use of new technologies to determine proved reserves if those technologies have been demonstrated to result in reliable conclusions about reserves volumes. Companies are required to report the independence and qualifications of their reserves preparer or auditor and file reports when a third party is relied upon to prepare reserves estimates or conduct a reserves audit. In January 2010, the FASB issued authoritative guidance on oil and gas reserve estimation and disclosure, aligning their requirements with the SEC's final rule. We have presented and applied this new guidance for the year ended December 31, 2009 herein.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the last three fiscal years. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and gas prices result in increased drilling activity in our areas of operations.

Quantitative and Qualitative Disclosures on Market Risks

Oil and Natural Gas Prices. Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the global supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse affect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. If oil prices decline by $10.00 per Bbl, then our PV-10 as of December 31, 2010 would have been lower by approximately $100.4 million. If natural gas prices decline by $1.00 per Mcf, then our PV-10 as of December 31, 2010 would decrease by approximately $32.9 million.

Our primary commodity risk management objective is to reduce volatility in our cash flows. Management makes recommendations on hedging that are approved by the board of directors before implementation. We enter into hedges for oil and natural gas using NYMEX futures or over-the-counter derivative financial instruments with only certain well-capitalized counterparties which have been approved by our board of directors.

The use of financial instruments may expose us to the risk of financial loss in certain circumstances, including instances when (1) sales volumes are less than expected requiring market purchases to meet commitments, or (2) our counterparties fail to purchase the contracted quantities of natural gas or otherwise fail to perform. To the extent that we engage in hedging activities, we may be prevented from realizing the benefits of favorable price changes in the physical market. However, we are similarly insulated against decreases in such prices. For a discussion of the hedges that we had in place as of April 30, 2011, see "*Business Hedging Activity*."

Presently, all of our hedging arrangements are concentrated with two counterparties, both of which are lenders under our credit facility. If this counterparty fails to perform its obligations, we may suffer financial loss or be prevented from realizing the benefits of favorable price changes in the physical market.

The result of natural gas market prices exceeding our swap prices or collar ceilings requires us to make payment for the settlement of our hedge derivatives, if owed by us, generally up to three business days before we receive market price cash payments from our customers. This could have a material adverse effect on our cash flows for the period between hedge settlement and payment for revenues earned.

Table of Contents

The following table provides a summary of derivative contracts as of October 31, 2011:

Settlement Period	Derivative Instrument	Total Notional Amount (Bbl/Mmbtu)	Average Floor Price	Average Ceiling Price	Fair Market Value of Asset (Liability)
					(In thousands)
Oil					
2011	Collar	239,552	$ 83.86	$ 133.45	$ 355
	Swap	62,428	64.36	64.36	(2,028)
2012	Collar	167,472	90.00	123.00	570
	Swap	116,708	63.03	63.03	(4,285)
2013	Collar	50,616	90.00	123.00	163
	Swap	75,417	61.50	61.50	(2,923)
Gas					
2011	Swap	108,580	7.10	7.10	285
2012	Swap	202,319	6.75	6.75	386
2013	Swap	154,806	6.40	6.40	199
					$ (7,278)

Interest Rates. We intend to use the net proceeds from this offering to repay outstanding indebtedness under our credit facility. At October 31, 2011, we had $149.1 million outstanding under our credit facility, which is subject to floating market rates of interest. Borrowings under our credit facility bear interest at a fluctuating rate that is tied to an adjusted base rate or LIBOR, at our option. Any increases in these interest rates can have an adverse impact on our results of operations and cash flow. Based on borrowings outstanding at October 31, 2011, a 100 basis point change in interest rates would change our annualized interest expense by approximately $1.5 million.

Counterparty and customer credit risk. In connection with our hedging activity, we have exposure to financial institutions in the form of derivative transactions. The lenders under our credit facility are currently the counterparties on our derivative instruments currently in place and have investment grade credit ratings. We expect that any future derivative transactions we enter into will be with these or other lenders under our credit facility that will carry an investment grade credit rating.

We are also subject to credit risk due to concentration of our oil and natural gas receivables with certain significant customers. See "*Business Principal Customers*" for further detail about our significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results. We review the credit rating, payment history and financial resources of our customers, but we do not require our customers to post collateral.

Table of Contents

BUSINESS

Overview

Bonanza Creek Energy, Inc. is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of onshore oil and associated liquids-rich natural gas in the United States. Our assets and operations are concentrated primarily in southern Arkansas (Mid-Continent region) and the DJ and North Park Basins in Colorado (Rocky Mountain region). In addition, we own and operate oil producing assets in the San Joaquin Basin (California region). Our management team has extensive experience acquiring and operating oil and gas properties, which we believe will contribute to the development of our sizable inventory of projects including those targeting the oily Cotton Valley sands in our Mid-Continent region and the Niobrara oil shale formation in our Rocky Mountain region. We operate approximately 99.4% and hold an average working interest of approximately 85.8% of our proved reserves, providing us with significant control over the rate of development of our long-lived, low-cost asset base.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves as of December 31, 2010, to be as follows:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Mid-Continent	3,725	9,094	745	5,985
Rocky Mountain	3,373	10,961		5,200
California	337	19		340
Undeveloped				
Mid-Continent	7,898	35,754	3,033	16,890
Rocky Mountain	2,729	7,011		3,898
California	539	45		547
Total Proved	18,601	62,884	3,778	32,860

Our average net daily production rate during October 2011 was 4,812 Boe/d, which consisted of 72.5% oil and natural gas liquids, and during November 2011 was 6,105 Boe/d, which consisted of 71% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2010(1)					Estimated Production for the Month Ended November 30, 2011		Projected 2011 Capital Expenditures	Net Proved Undeveloped Drilling Locations as of December 31, 2010
	Total Proved (MBoe)	% of Total	% Proved Developed	% Oil and Liquids	PV-10 ($ in MM)(2)	Average Net Daily Production (Boe/d)	% of Total	(millions)(3)	
Mid-Continent	22,876	69.6%	26.2%	67.3%	$ 313.3	3,223	52.8%	$ 85.2	151.3
Rocky Mountain	9,098	27.7	57.2	67.1	135.3	2,706	44.3	74.9	77.3
California	886	2.7	38.3	98.8	13.0	176	2.9	2.0	13.6
Total	32,860	100.0%	35.1%	68.1%	$ 461.6	6,105	100%	$ 162.1	242.2

(1)

Proved reserves were calculated using prices equal to the twelve-month unweighted arithmetic average of the first-day-of-the-month prices for each of the preceding twelve months which were $79.43 per Bbl of crude oil and an average price of $4.38 per MMBtu of natural gas. Adjustments were

Table of Contents

made for location and the grade of the underlying resource, which resulted in $4.50 per Bbl of crude oil and an increase of $0.43 per MMBtu of natural gas.

(2)

PV-10 is a non-GAAP financial measure and represents the present value of estimated future cash inflows from proved crude oil and natural gas reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash inflows and using the twelve month unweighted arithmetic average of the first-day-of-the-month price for each of the preceding twelve months. PV-10 differs from Standardized Measure because it does not include the effect of future income taxes. For a reconciliation of our Standardized Measure to PV-10, see "*Summary Reserve and Operations Data Non-GAAP Financial Measures and Reconciliation PV-10*."

(3)

Projected capital expenditures for our Mid-Continent region include $17.7 million for the construction of the Dorcheat gas processing facility, which was completed in September 2011.

Development Projects by Region

Mid-Continent: In southern Arkansas we are primarily targeting the oil-bearing Cotton Valley sands in the Dorcheat Macedonia and McKamie Patton fields. As of December 31, 2010, our estimated proved reserves in this region were 22,876 MBoe, 67.3% of which were oil and natural gas liquids and 26.2% of which were proved developed. We currently operate 138 gross (120.5 net) producing wells and, as of December 31, 2010, have an identified drilling inventory of approximately 188 gross (151.3 net) PUD drilling locations on our acreage. In 2011 we expect to drill and complete 40 gross (34.8 net) wells in the Dorcheat Macedonia field at a cost of approximately $1.7 million per well, and 2 gross (2.0 net) wells in the McKamie Patton field at a cost of $1.2 million per well. As of October 31, 2011 we had drilled 36 gross (31.5 net) wells in the Dorcheat Macedonia field.

We also own and operate the McKamie and Dorcheat gas processing facilities and approximately 150 miles of associated gathering pipelines that serve our acreage position in southern Arkansas. These facilities have a combined maximum processing capacity of 27.5 MMcf/d of natural gas and 58,000 gallons per day of natural gas liquids. These two facilities currently process all of the natural gas that we produce from the Dorcheat Macedonia and McKamie Patton fields.

Rocky Mountain: In the DJ and North Park Basins in Colorado, we hold 83,617 gross (62,688 net) acres that currently produce oil, natural gas and CO_2 from the Pierre B, Niobrara, Codell, J-Sand, D-Sand and Dakota formations. As of December 31, 2010, our estimated proved reserves in this region were 9,098 MBoe, of which 67.1% were oil and 57.2% were proved developed. In the DJ Basin we control 29,262 net acres, as of December 31, 2010, and have identified approximately 93 gross (73.3 net) vertical PUD drilling locations targeting the Codell sand and Niobrara oil shale formations. In 2011, we expect to drill and complete 64 gross (63.0 net) vertical wells targeting the Codell sand and Niobrara oil shale formations, at a cost of approximately $0.8 million per well. As of October 31, 2011, we had completed 64 gross (63.0 net) of our planned 2011 wells. In addition, we believe that horizontal drilling and multi-stage fracture completion techniques are an attractive alternative to vertical well completions for the Niobrara oil shale. To date, we have drilled all four, and completed three, of our operated horizontal Niobrara wells in the DJ Basin planned for 2011. In the North Park Basin we control 33,426 net acres and, as of December 31, 2010, have identified 4 gross (4.0 net) vertical PUD locations. We have identified highly fractured and dual porosity areas which we believe will support vertical and horizontal drilling techniques for the Niobrara. The development and testing of the North Park Basin began this year with the drilling of 2 gross (2.0 net) vertical wells at a drilling and evaluation cost of approximately $2.9 million for the first well and an estimated $2.2 million for the second well.

California: In California, we employ thermal techniques to recover heavy oil in the Kern River and Midway Sunset fields, and we produce medium gravity oil from the Greeley and Sargent fields. As of December 31, 2010, our estimated proved reserves in this region were 886 MBoe, of which 98.8% were oil and 38.3% were proved developed. We have identified approximately 18 gross (13.6 net) PUD drilling

Table of Contents

opportunities in these fields. In 2011, we expect to drill 3 gross (1.5 net) wells with individual well costs ranging from approximately $0.3 to $1.0 million. As of October 31, 2011, we have drilled and completed 3 gross (1.5 net) wells.

Recent Developments

On July 24, 2011, we completed our first operated horizontal Niobrara well, the State Antelope 11-2Hz, and reported a 24-hour rate after cleanup on August 1, 2011 of 738 Boe/d and a 30-day rate of 362 Boe/d. Our second operated horizontal Niobrara well, the North Platte 44-11-28Hz, was completed on August 9, 2011 and reported a 24-hour rate after cleanup on August 19, 2011 of 887 Boe/d and a 30-day rate of 599 Boe/d. These two wells cost an average of $3.9 million per well. We recently completed our third operated horizontal Niobrara well, the State Antelope 11-14-1Hz, reporting a 24-hour rate after cleanup on November 1, 2011 of 886 Boe/d. Our fourth and final operated horizontal Niobrara well of 2011, the State Whitetail 14-11-36Hz, has been drilled and is currently being fracture stimulated. We expect costs for these two wells to average $4.3 million per well.

We recently approved our 2012 capital expenditure budget, pursuant to which we expect to spend approximately $250 million to continue developing our oil and gas properties across our regions and to expand our gas processing facilities in southern Arkansas.

Our Business Strategies

Our goal is to increase stockholder value by investing capital to increase our production, cash flow and proved reserves. We intend to accomplish this goal by focusing on the following key strategies:

Increase Production from Existing Low-Cost Proved Inventory. In the near term, we intend to accelerate the drilling of our lower-risk vertical PUD drilling locations in southern Arkansas and in the oily Codell and Niobrara formation of the DJ Basin. Substantially all of these infill locations are characterized by multiple productive horizons.

Test and Evaluate Our Niobrara Oil Shale Acreage. We hold approximately 83,617 gross (62,688 net) acres prospective for the development of the Niobrara oil shale in Weld and Jackson Counties, Colorado, and own approximately 17,400 acres of proprietary 3-D seismic data covering our acreage position in Weld County, which aids in identifying our horizontal drilling locations. Although full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, we and other operators in the region, including Noble Energy (DJ Basin), Anadarko Petroleum (DJ Basin), EOG Resources (DJ Basin and North Park Basin), and PDC Energy (DJ Basin) have recently applied horizontal drilling and multi-stage fracture stimulation techniques to enhance recoveries and economic returns.

Exploit Additional Development Opportunities. We are evaluating additional resource potential opportunities that could result in future development projects on several of our assets. For example, we have evaluated and believe we may achieve attractive returns by exploiting the Lower Smackover (Brown Dense) trend in our southern Arkansas acreage. We have 5,672 net acres prospective for the Brown Dense. Finally, we believe there are additional thermal recovery opportunities in California.

Pursue Accretive Acquisitions. We intend to pursue bolt-on acquisitions in regions where we operate and where we believe we possess a strategic or technical advantage, such as southern Arkansas where we own a gas processing facility and the associated infrastructure. In addition, we intend to focus on other oil and liquids-rich opportunities where we believe our operational experience will enhance the value and performance of acquired properties.

Table of Contents

Maintain High Degree of Operatorship. We currently have and intend to maintain a high working interest in our assets, thereby allowing us to leverage our technical, operating and management skills and control the timing of our capital expenditures.

Our Competitive Strengths

We believe the following combination of strengths will enable us to implement our strategies:

Significant Drilling Inventory. We have identified 303 gross (242.2 net) PUD drilling locations, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. Since 2005, we have accumulated 62,688 net acres in Weld and Jackson Counties, Colorado, targeting the Niobrara formation. Our acreage is proximate to horizontal drilling operations which have been successfully completed by other operators. Significant increases in permitting, spud notices involving the Niobrara formation in these counties have made this area one of the most active oil shale plays in the United States. In Weld County the average initial 30-day production rate is 318 Boe/d from 70 wells with oil and gas production and no dry holes reported to the state regulatory commission. In the North Park Basin, EOG Resources has completed seven wells horizontally in an area of the Niobrara that we believe to be geologically similar to our acreage position based on electric and porosity log response. The average initial 30-day production rate for these wells is 294 Boe/d.

We believe our significant acreage position in the Niobrara represents production, reserve and value growth potential and that the continued development of this play by other operators validates our investment in this play and will result in the continued development of infrastructure in the area. Geological risks associated with our Weld County acreage position have been mitigated by the high volume of data provided through the drilling, completion and production of thousands of vertical wells in the Niobrara in close proximity to and within our acreage. Additionally, since oil and gas production has been established, gathering systems are in place in this region, enabling a short time period from well completion to first product sales.

In Weld County, we own approximately 17,400 acres of proprietary 3-D seismic. Because we have exclusive access to this data, we are in a position to preferentially orient horizontal wells targeting the Niobrara on our acreage position and have the ability to identify and avoid drilling hazards, such as faulting.

In Jackson County, we own 22 proprietary 2-D seismic lines. Interpretation of this proprietary seismic data affords us the geologic image necessary to plan our Niobrara development program. In addition, our position of 39,030 net acres provides us with economies of scale to develop the Niobrara, as well as to explore the resource potential in other horizons.

While there is currently no pipeline capacity in Jackson County to move natural gas to market, successful drilling of horizontal Niobrara wells by us or other operators would likely justify installation of gas pipeline infrastructure.

High Degree of Operational Control. We hold an average working interest in our properties of approximately 85.8% and operate approximately 99.4% of our estimated proved reserves, which allows us to employ the drilling and completion techniques we believe to be most effective, manage costs and control the timing and allocation of our capital expenditures.

Gas Processing Capability in Southern Arkansas. The processing of our natural gas at our McKamie facility improves our well development economics in southern Arkansas. In addition, we expanded our infrastructure by adding an additional gas processing facility in our Dorcheat Macedonia field to accommodate future drilling on our acreage in this region.

Table of Contents

Experienced Management. Our senior management team averages more than 31 years of experience, and certain members of our executive management have worked together for over 24 years. Our management team has significant acquisition experience, having negotiated and closed more than 12 acquisition transactions since 2006.

Financial Flexibility. Our capital structure is intended to provide a high degree of financial flexibility to grow our asset base, both through organic projects and opportunistic acquisitions. As adjusted for the completion of this offering, our liquidity as of October 31, 2011 was approximately $232.0 million, comprised of $220 million of availability under our credit facility and approximately $12.0 million of cash on hand.

Bonanza Creek Acquisition History

Acquiring properties that are complementary to our existing positions or that have significant undeveloped resource potential has been an important part of our growth strategy. The following describes some of the recent acquisitions we have made to build our current position in the Mid-Continent, the Rocky Mountain and California regions:

Mid-Continent. In April 2008, we acquired properties in Union, Lafayette and Columbia counties, Arkansas, that included 93 producing wells (68 operated) with an average working interest of 73% and 14,980 gross (12,147 net) acres. Included in the acquisition was a 15 MMcf/d gas plant with approximately 150 miles of gathering system, which processes production from both the properties and other producers in the area. We acquired 3,469 gross (3,018 net) acres in the Dorcheat Macedonia Field, Columbia County, Arkansas in December 2010. The assets included a non-operated position in our Dorcheat Macedonia field as well as operated wells in which we were a non-operated owner.

Rocky Mountain. We completed four DJ Basin acquisitions in 2005 and 2006, consisting of approximately 39,728 gross (27,463 net) acres. In December 2010, we purchased an additional 2,970 gross (2,279 net) acres in the DJ Basin, including 39 operated and 3 non-operated wells primarily completed in the Codell/Niobrara formations. We purchased the McCallum Field, located in the North Park Basin, Jackson County, Colorado in May 2006, along with 2 non-producing wells and undeveloped acreage in November 2007.

California. In 2006 and 2007, we acquired 8,940 gross (5,012 net) acres in Kern and Santa Clara Counties, California consisting of a mix of heavy and light oil producing assets.

Our Operations

Our operations are mainly focused in the Mid-Continent, specifically the Dorcheat Macedonia field located in Columbia County, Arkansas and in the DJ Basin and the North Park Basin in the Rocky Mountain region.

Mid-Continent Region

Substantially all of our proved reserves and our identified PUD drilling locations in our Mid-Continent acreage are located in the Dorcheat Macedonia field and the McKamie Patton field.

Dorcheat Macedonia

In the Dorcheat Macedonia field we average a 85.3% working interest and 70.3% net revenue interest, and all of our acreage is held by production. We have approximately 104 gross (88.7 net) producing wells and our average net daily production during November 2011 was approximately 1,871 Boe/d from a proved reserves base of 15,247 MBoe, of which about 64.5% is oil and natural gas liquids. Productive reservoirs range in depth from 4,500 to 9,000 feet in depth. Those reservoirs have

Table of Contents

included the Smackover, Cotton Valley and the Pettet. Our primary development target is the Cotton Valley.

The Dorcheat Macedonia field was originally developed for the Smackover in the 1940s on 80-acre units with the initial well drilled in the center of the unit. The Cotton Valley and shallower reservoirs were developed in the 1970s and 1980s. Field rules for the development of the Cotton Valley provided for the drilling of a Cotton Valley well in the center of the two 40-acre tracts that comprised the 80-acre unit, with a location tolerance of no more than 150 feet from a straight line between the two centers of the 40 acres, which resulted in two Cotton Valley wells and a Smackover well confined to an 11-acre oval within the center of the unit, leaving 69 acres within each unit without a wellbore penetration. Subsequent development of the Cotton Valley has reduced the spacing to approximately 20 acres in certain areas of the field, and our continued development will ultimately reduce spacing to ten acres. The oil-bearing Cotton Valley sands directly overlie the Bossier Shale and have relatively low porosity and permeability. Deposited as a series of sand and shale sequences, the resulting reservoir is extremely lenticular in nature. Based on reservoir parameters, fracture stimulation is employed to complete these multiple stacked pay zones. The oil in these sands has an American Petroleum Institute (API) gravity of approximately 45° and is primarily lifted by rod pump.

Historically, the Dorcheat Macedonia reservoirs have responded favorably to fracture stimulation. Beginning in the fourth quarter of 2009 we began to implement pinpoint fracture stimulation utilizing coiled tubing. Post-fracture treatment tracer work has confirmed that pinpoint fracture placement provides much better coverage and penetration of the intended producing intervals. Early results from wells employing this technique have seen initial production rates higher than historic and show stimulation of previously unstimulated zones.

As of December 31, 2010, we have identified approximately 179 gross (142.6 net) PUD drilling locations on our acreage in this area. Currently, we have budgeted for 2011 capital expenditures of $54.4 million for the development of our Dorcheat Macedonia acreage. Under this budget we expect to drill 40 gross (34.9 net) additional infill PUD locations in the field this year. We expect to drill vertically to an average depth of approximately 8,700 feet for each location with a total expected drill and complete cost per well of approximately $1.7 million, approximately $1.6 million of which will be for initial drilling and completion. Typically, these wells take an average of 12 days to drill and three days to complete. The average initial 30-day production rate for the 41 wells we drilled in the Dorcheat Macedonia field and had on production since October 2009 was 137 Boe/d. Our typical well has a hyperbolic decline rate and an average economic life of 22 years. As of October 31, 2011, we have drilled 36 gross (31.5 net) of the planned 2011 wells.

Other Mid-Continent

We own additional interests in the Mid-Continent region near the Dorcheat Macedonia field. These include interests in the McKamie-Patton, Atlanta and Beach Creek fields. Our estimated proved reserves in these fields as of December 31, 2010 were approximately 1,947.8 MBoe, and average net daily production during November 2011 was approximately 253 Boe/d. We plan to drill 2 gross (2.0 net) wells in the McKamie-Patton field in 2011 at a cost of $1.2 million per well.

Gas Processing Facilities

The McKamie processing facility is located in Lafayette County, Arkansas and is strategically located to serve our production in the region. This facility has a processing capacity of 15 MMcf/d of natural gas and 30,000 gallons per day of natural gas liquids. The facility processes natural gas and natural gas liquids, fractionates liquids into three components for sale, and sells four products at the facility's tailgate: propane, butane, natural gasolines and natural gas. The facility is a Process Safety Management maintained facility, and the main components were placed into service in the mid-1980s. The facility is currently processing approximately 10 MMcf/d of natural gas comprised of 9.2 MMcf/d of Bonanza-

Table of Contents

operated natural gas and 0.8 MMcf/d of third-party natural gas. We also own approximately 150 miles of natural gas gathering pipeline that serves the facility and surrounding field areas and 32 miles of right-of-way crossing Lafayette County that can be utilized to connect the facility to other gas fields or future sales outlets. Natural gas is sold at the tailgate of the facility into a CenterPoint pipeline connection. Fractionated natural gas liquids are held on site and trucked out by the buyer, Dufour Petroleum. All gas entering the facility is processed in accordance with percent-of-proceeds contracts with upstream counterparties.

In order to accommodate increased gas volumes, we invested $17.7 million to build a 12.5 MMcf/d processing facility with associated 28,000 gallons per day of natural gas liquids capacity in our Dorcheat Macedonia field, which we completed in September of this year. The construction of this new facility is in conjunction with our continued development of the field. In November 2011, we executed an agreement for the expansion of this facility. Our capital commitments under this agreement are $7.5 million, which is a portion of the total cost for the expansion. We spent an additional $2.5 million on facilities throughout the company.

Combined, the facilities had an average net output of 1,098 Boe/d based on the facility contracts for the month of November 2011. Our ownership of this facility and pipeline system provides us with the benefit of controlling processing and compression of our natural gas production and timing of connection to our newly completed wells. While we own the majority of the gas entering the facility, we also process some third-party natural gas through the system. Neither the revenue nor volumes of this third-party natural gas is included in our reserve reports.

Rocky Mountain Region

The two main areas in which we operate in the Rocky Mountain region are the DJ Basin in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. The Niobrara oil shale is present across substantially all of our acreage in these two areas.

While full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, operators in the region, including Noble Energy, Anadarko Petroleum, EOG Resources, and PDC Energy, have recently applied horizontal drilling and multi-stage fracture stimulation techniques in an effort to improve economic returns.

The Niobrara oil shale contains a high proportion of carbonates, including brittle, calcareous chalk benches in addition to oil bearing shales. Permeability and porosity are sufficient in the chalk components of the Niobrara to permit economic oil recovery. Although natural fracturing is present in the Niobrara, hydraulic fracturing is typically required to make the reservoir commercially productive.

The DJ Basin is believed to occupy the most prospective area of the Niobrara. Within the DJ Basin, the Niobrara oil shale is 200 to 300 feet thick and comprises the Smoky Hill Shale and Fort Hayes Limestone. In addition to the DJ Basin, Niobrara oil shale exploration is ongoing in the North Park, Piceance, Raton and Sand Wash basins in Colorado and the southern Powder River Basin in Wyoming.

Recently the Niobrara oil shale has been the scene of increasing interest as various companies such as Noble Energy, Anadarko Petroleum, EOG Resources, PDC Energy and Rex Energy are leasing, permitting and drilling wells targeting the Niobrara oil shale in Weld County, Colorado, the North Park Basin in Jackson County, Colorado, and in Laramie County, Wyoming. These operators have demonstrated that the Niobrara oil shale is prospective for the application of horizontal drilling and multi-stage fracture stimulation completion techniques. These completion techniques have been responsible for the substantial increase in drilling and production from various oil shales such as the Bakken formation in North Dakota and the Eagle Ford in southern Texas.

DJ Basin Weld County, Colorado

The DJ Basin is a geologic structural basin centered in eastern Colorado that extends into southeast Wyoming, western Nebraska, and western Kansas. Our operations in the DJ Basin are in the oil window of the Niobrara and as of October 31, 2011 consisted of approximately 42,218 gross (29,262 net) total acres.

Table of Contents

Commercial development activities began in the DJ Basin in the 1970s. It originally produced natural gas from tight sand reservoirs in the Dakota and J Sands. In the 1990s the shallower Codell sands and Niobrara oil shale were developed and produced oil and associated natural gas. These zones range from 6,300 feet to 8,000 feet with average porosity of 6% to 10% and relatively low permeability of 0.3 millidarcies.

Historically, we have drilled vertical wells through multiple zones. We then complete and fracture stimulate one of the Dakota or J Sand zones or both the Codell sand and the Niobrara shale zones. We are beginning to augment the vertical development of our Weld County acreage using horizontal drilling techniques in the Niobrara oil shale.

DJ Basin Vertical Exploitation

Our estimated proved reserves in the DJ Basin were 8,402 MBoe at December 31, 2010. As of October 31, 2011, we had a total of 178 gross (170.8 net) producing wells and our net average daily production during November 2011 was approximately 1,760 Boe/d. Our working interest for all producing wells averages 95.9% and our net revenue interest is approximately 78.7%.

We drill wells vertically in this area to an average depth of approximately 7,000 feet, targeting both the Niobrara and Codell horizons with the same well bore. We have budgeted drilling and completion costs per well of approximately $640,000 and we expect to incur an additional $195,000 per well for refracture stimulation, to be completed in the fifth year after initial completion. Typically, these wells take an average of five days to drill and one day to complete. The average initial 30-day production rate for the 35 wells drilled and producing in 2010 was 56 Boe/d. Our typical well has a hyperbolic decline rate and an average economic life of 32 years. As of December 31, 2010, we have identified approximately 93 gross (73.3 net) PUD vertical drilling locations on our acreage in this area.

We intend to employ a mixture of vertical and horizontal drilling techniques with multi-stage fracture completions across our entire Weld County acreage position. Of these acres, 1,640 gross (1,338 net) acres represent proved drilling locations and 19,758 gross (9,798 net) acres represent unproven drilling locations.

The Codell sandstone and Niobrara oil shale are blanket deposits in the DJ Basin. We continue to expand our proved acreage with our vertical program by drilling non-proved locations. Currently, we estimate our capital expenditures for 2011 will be $43.7 million, which includes drilling 64 gross (63.0 net) vertical wells of which 14 are proved and 50 are non-proved. As of October 31, 2011, we had completed 64 gross (63.0 net) of our 2011 planned wells, 14 proved and 50 non-proved.

DJ Basin Horizontal Exploitation

Our entire 42,218 gross (29,262 net) acre position in Weld County is prospective for the Niobrara formation using horizontal drilling and multi-stage fracture completion technology. On the eastern portion of our acreage, we have 3-D seismic data covering 17,400 gross acres, in addition to having drilled 19 vertical wells and currently operating 31 vertical wells, further delineating the play for horizontal development.

Our acreage position in the DJ Basin is offset by Noble Energy, Anadarko Petroleum, EOG Resources, Marathon Oil, and PDC Energy. Noble and PDC have drilled horizontal wells in the area of our acreage and reported initial production rates ranging from 162 Boe/d to 895 Boe/d. Wells on the lower range tend to have shorter horizontal lateral lengths and smaller volumes of proppant used in the fracture stimulation. Noble Energy recently announced the results of the 70 Ranch USX BB #25-99HZ located within our acreage. The reported initial production rate was 895 Boe/d with a 30-day average of 406 Boe/d. The well was completed with a 3,540 foot lateral in the Niobrara B interval. A fracture stimulation treatment was executed with 3.9 million pounds of proppant. In addition, Anadarko is producing from 11 horizontal wells within the Wattenberg field, achieving strong initial rates with high liquids yields, averaging initial production rates of approximately 850 Boe/d. Its best horizontal well to date, the Dolph

27-1HZ, demonstrated an initial production rate of 1,505 Boe/d. We estimate that our capital expenditures for 2011 will be $18.1 million, which includes drilling 4 gross (3.8 net) wells. We completed our first operated horizontal Niobrara well, the State Antelope 11-2Hz, on July 24, 2011 and reported a 24-hour rate after cleanup on August 1, 2011 of 738 Boe/d and a 30-day average rate of 362 Boe/d. Our second operated horizontal Niobrara well, the North Platte 44-11-28Hz, was completed on August 9, 2011 and reported a 24-hour rate after cleanup on August 19, 2011 of 887 Boe/d and a 30-day rate of 599 Boe/d. We recently completed our third operated horizontal Niobrara well, the State Antelope 11-14-1Hz, reporting a 24-hour rate after cleanup on November 1, 2011 of 866 Boe/d. Our fourth and final operated horizontal Niobrara well of 2011 has been drilled and is currently being fracture stimulated. The cost of the first two wells averaged $3.9 million, not including $0.5 million of non-recurring costs relating to micro-seismic and the use of radioactive tracers and $0.4 million of future shared costs with other wells. We anticipate costs for the remaining two wells to average $4.3 million per well.

North Park Basin Jackson County, Colorado

Current Operations. We control 41,399 gross (33,426 net) acres in the North Park Basin in northern Jackson County, Colorado and, as of December 30, 2010, have identified 4 gross (4.0 net) vertical PUD locations. The Basin is divided into three principal opportunities: the North and South McCallum units and the non-unit acreage. We operate the North and South McCallum fields, which currently produce CO_2 and light oil from the Dakota/Lakota Group sandstones and oil from a shallow waterflood from the Pierre B sandstone.

The McCallum field covers 10,277 gross (8,606 net) acres of federal land with the majority of the oil production coming from a waterflood in the Pierre B formation and the CO_2 production coming from naturally flowing Dakota wells. Oil production is trucked to the market while CO_2 production is sent to a Praxair plant for processing and delivery to the market.

In the North Park Basin, our estimated proved reserves as of December 31, 2010 were approximately 696.1 MBoe, of which 100% were oil. Our average net production during November 2011 was approximately 169 Boe/d. None of our CO_2 production is currently reflected in our reserve reports.

Niobrara Oil Shale Potential. All of our 41,399 gross (33,426 net) acres in the North Park Basin are prospective for the Niobrara oil shale. In 2007, EOG Resources began a testing program in the North Park Basin. As of October 31, 2011 EOG Resources has reported production on seven horizontal wells targeting the Niobrara. The average initial 30-day production rate from these wells has been 294 Boe/d.

We currently plan to drill vertical wells to develop the Niobrara across the top of the McCallum anticline due to the presence of natural fracturing and the potential for other productive horizontals including the Pierre B, Dakota/Lakota, Sundance and Jelm reservoirs. We also plan to drill horizontal wells and, to a lesser extent, vertical wells to capture the Niobrara oil shale resource downdip of the crest of the McCallum structure.

Currently, there is no take away capacity for natural gas from the North Park Basin. Any future commercial development of the Niobrara oil shale in this area will require significant investment to construct the infrastructure necessary to gather and transport associated natural gas produced from the formation. Although we are not aware of any current plans to construct or fund this construction in the immediate future, we believe that mid-stream companies will construct the necessary infrastructure once the level of commercial natural gas development warrants the capital outlay.

California

In California, we own acreage in four fields: Kern River, Midway Sunset and Greeley, which we operate, and Sargent, which we do not. Our estimated proved reserves in California were 886 MBoe at December 31, 2010. As of November 30, 2011, we had a total of 54 gross (45.1 net) producing wells and

Table of Contents

our average net daily production was approximately 176 Boe/d. Our working interest for all producing wells averages 83.5% and our net revenue interest is approximately 70.6%. As of December 31, 2010, we have identified approximately 18 gross (13.6 net) PUD locations in California. Currently, we estimate our capital expenditures for 2011 will be $2.0 million, which includes drilling 3 gross (1.5 net) wells, all of which are PUD.

We believe the opportunity to see additional growth exists on the two thermal properties: Kern River and Midway Sunset. Combined, these two properties have up to 16.5 MMBoe of 11° to 12° API gravity crude oil originally in place with very small amounts of production to date. We believe that reservoir parameters are good for thermal operations in both areas. In Kern River, porosities average 31% and permeabilities average from 1,000 to 5,000 millidarcies. In Midway Sunset, porosities average 32% and permeabilities range from 400 to 600 millidarcies. Proved reserves for these two areas are only 573 MBoe, which we believe demonstrates an opportunity for future growth in reserves once thermal operations take effect.

Both Greeley and Sargent produce a lighter crude and do not require thermal stimulation. Potential upside exists in the Sargent field by implementing fracture stimulation of the Purisima sands. These sands have permeability of under 500 millidarcies and porosities of 32%. The operator at Sargent drilled and fracture stimulated 3 gross (1.5 net) wells through October 31, 2011.

Proved Undeveloped Reserves

At December 31, 2010, our proved undeveloped reserves were 21,334.6 Mboe, an increase of 7,343.3 Mboe over our December 31, 2009 proved undeveloped reserves of 13,991.3 Mboe. The reserve change and number of net wells is summarized in the table below for each our regions. The largest changes were realized in the Mid-Continent and Rocky Mountain regions resulting primarily from our acquisition of HEC. This acquisition added 6,535.5 Mboe and accounted for 89.0% of the total increase of 7,343.3 Mboe in 2010. Also contributing to our growth in proved undeveloped reserves were improved techniques in stimulating smaller, tighter, higher gas-oil ratio sands in the Mid-Continent region that were implemented in 2009 and resulted in a positive revision of our forecast in 2010. An active drilling program in 2010 converted 1,623.2 MBoe of proved undeveloped reserves to proved developed reserves, reducing the PUD category by that amount. Our total capital expenditure associated with the conversion of proved undeveloped reserves to proved developed reserves in 2010 was $21.6 million.

Proved Undeveloped Reserves

	2009		2010		Difference	
Region/Area	**MBoe**	**Net Wells**	**MBoe**	**Net Wells**	**MBoe**	**Net Wells**
Mid Continent	11,486.5	109.6	16,890.2	163.3	5,403.7	53.7
Rocky Mountain	1,687.6	30.1	3,897.6	79.3	2,210.0	49.2
California	817.2	30.2	546.7	16.8	(270.5)	(13.4)
Total	13,991.3	169.8	21,334.6	259.4	7,343.3	89.6

Independent Reserve Engineers

The proved reserves estimate for the company for the year ended December 31, 2010 and for BCEC for the year ended December 31, 2009 shown herein have been independently prepared by Cawley, Gillespie & Associates, Inc., which was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within Cawley, Gillespie & Associates, Inc., the technical person primarily responsible for preparing the estimates shown herein, was Zane Meekins. Mr. Meekins has been practicing consulting petroleum engineering at Cawley, Gillespie & Associates, Inc. since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 23 years of practical experience in petroleum engineering, with over 21 years experience in the estimation and evaluation of reserves. He graduated from Texas A&M

Table of Contents

University in 1987 with a BS in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

Technology Used to Establish Proved Reserves

As referred to in this prospectus, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, Cawley, Gillespie & Associates, Inc. employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, 3-D seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and completion using similar techniques. The evaluation included an assessment of the beneficial impact of the use of multi-stage hydraulic fracture stimulation treatments on estimated recoverable reserves. In addition to assessing reservoir continuity, geologic data from well logs, core analyses and 3-D seismic data were used to estimate original oil in place in certain areas.

Internal Controls over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserves estimation process. Our Executive Vice President Engineering and Planning is the technical person within the company primarily responsible for overseeing the preparation of our reserves estimates. He has over 29 years of industry experience and has evaluated numerous properties throughout the United States and Canada with an emphasis on California in light oil and natural gas, heavy oil, conventional and unconventional reservoirs, operations, reservoir development and property evaluation. He holds a Bachelors of Science degree in Petroleum Engineering and is an active member with the Society of Petroleum Engineers.

Throughout each fiscal year, our technical team meets with representatives of our independent reserve engineers to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. Historically, we had no formal committee specifically designated to review our reserves reporting and our reserves estimation process, and a preliminary copy of the reserve report was reviewed by our Executive Vice President Engineering and Planning with representatives of our independent reserve engineers and internal technical staff. We have recently designated a Reserve Committee of our board of directors which will actively oversee our reserve reporting process. See "*Management Committees of the Board of Directors Reserve Committee*."

Table of Contents

Operating Data

The following table sets forth our operating data for the three years ended December 31, 2008, 2009 and 2010.

	2008	2009	2010
Oil:			
Production (MBbls)	453.7	507.4	481.6
Average sales price (per Bbl), including hedges	$ 79.59	$ 67.40	$ 74.32
Average sales price (per Bbl), excluding hedges	$ 88.09	$ 54.40	$ 73.66
Natural Gas:			
Production (MMcf)	668.9	939.0	1,334.9
Average sales price (per Mcf), including hedges	$ 7.93	$ 5.05	$ 5.33
Average sales price (per Mcf), excluding hedges	$ 7.72	$ 3.91	$ 4.77
Natural Gas Liquids:			
Production (MBbls)	35.5	69.1	129.6
Average sales price (per Bbl), including hedges	$ 57.45	$ 41.77	$ 56.22
Average sales price (per Bbl), excluding hedges	$ 57.45	$ 41.77	$ 56.22
Oil Equivalents:			
Production (MBoe)	600.7	733.0	833.7
Average daily production (Boe/d)	1,641	2,008	2,284
Average Production Costs (per Boe)[(1)]	$ 34.02	$ 18.35	$ 18.28

(1) Excludes ad valorem and severance taxes.

Principal Customers

Two of our customers, Lion Oil and Plains Marketing, comprised 47% and 39%, respectively, of total revenue for the year ended December 31, 2010. Lion Oil and Plains Marketing comprised 37% and 44%, respectively, of total revenue for the nine months ended September 30, 2011.

Delivery Commitments

We do not have any material delivery commitments.

Productive Wells

The following table sets forth the number of oil and natural gas wells in which we owned a working interest at October 31, 2011.

	Oil		Natural Gas[(1)]		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	139	120.7			139	120.7	138	120.5
Rocky Mountain	248	240.6			248	240.6	245	239.6
California	54	45.1			54	45.1	41	38.6
Total	441	406.4			441	406.4	424	398.6

(1) All gas production is associated gas from producing oil wells.

Table of Contents

Acreage

The following table sets forth certain information with respect to our developed and undeveloped acreage as of October 31, 2011.

	Undeveloped		Developed	
	Gross	Net	Gross	Net
Mid-Continent			14,980	13,474
Rocky Mountain[(1)]	44,035	30,296	39,582	32,392
California[(2)]	200	144	8,740	4,868
Total	44,235	30,440	63,302	50,734

(1) Assuming successful wells are not drilled to develop the Rocky Mountain acreage and leases are not extended, leaseholds expiring over the next three years will be 43 net acres in 2011, 3,440 net acres in 2012 and 11,355 net acres in 2013.

(2) Assuming successful wells are not drilled to develop the California acreage and leases are not extended, leaseholds expiring over the next three years will be zero net acres in 2011, 15 net acres in 2012 and 36 net acres in 2013.

Drilling Activity

Exploratory

The following table describes the exploratory wells we drilled during the years ended December 31, 2008, 2009 and 2010.

	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2008	6	6.0			6	6.0
2009						
2010	15	15.0			15	15.0

Development

The following table describes the development wells we drilled during the years ended December 31, 2008, 2009 and 2010.

	Productive Wells		Dry Wells		Total	
Year	Gross	Net	Gross	Net	Gross	Net
2008	27	26.8			27	26.8
2009[(1)]						
2010[(1)]	27	27.0			27	27.0

(1) We contract operated for HEC from May 2009 until we acquired the properties in December 2010. Excluded from the development activity are 4 wells (2.5 net) and 12 wells (9.0 net) drilled as contract operator for HEC during years 2009 and 2010, respectively, that we had a minority working interest.

Table of Contents

Present Activity

The following table describes drilling activities as of October 31, 2011.

	Development Wells		Exploratory Wells		Total	
	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	1.0	1.0			1.0	1.0
Rocky Mountain					0.0	0.0
California					0.0	0.0
Total	1.0	1.0	0.0	0.0	1.0	1.0

Hedging Activity

In addition to supply and demand, oil and gas prices are affected by seasonal, economic and geo-political factors that we can neither control nor predict. We attempt to mitigate a portion of our price risk through the use of derivative transactions.

As of October 31, 2011, we had the following economic hedges in place, which settle monthly:

Oil Contracts

Period	Type	Volume/Month (Bbls)	Index[(1)]	Floor	Ceiling	Fixed Price
November 1 - December 31, 2011	Collar	15,392	WTI	$ 90.00	$ 123.00	
November 1 - December 31, 2011	Collar	24,400	WTI	$ 80.00	$ 140.00	
November 1 - December 31, 2011	Swap	8,626	WTI			$ 64.45
November 1 - December 31, 2011	Swap	1,600	WTI			$ 63.87
January 1 - December 31, 2012	Collar	13,956	WTI	$ 90.00	$ 123.00	
January 1 - December 31, 2012	Swap	8,206	WTI			$ 62.95
January 1 - December 31, 2012	Swap	1,520	WTI			$ 63.47
January 1 - April 31, 2013	Collar	12,654	WTI	$ 90.00	$ 123.00	
January 1 - October 31, 2013	Swap	7,542	WTI			$ 61.50

Natural Gas Contracts

Period	Type	Volume/Month (MMBtu)	Index	Fixed Price
November 1 - December 31, 2011	Swap	17,770	Henry Hub	$ 7.10
January 1 - December 31, 2012	Swap	16,860	Henry Hub	$ 6.75
January 1 - October 31, 2013	Swap	15,481	Henry Hub	$ 6.40

(1) WTI refers to West Texas Intermediate price as quoted on the New York Mercantile Exchange.

We did not apply hedge accounting treatment to any of the 2010 and 2011 contracts. Settlements on these contracts will not impact our realized commodity prices during the periods they cover. Instead, any settlements on these contracts are shown as a component of other income and expenses as a realized (gain) loss on derivative instruments. See Note 12 to our consolidated financial statements for additional information regarding our derivative instruments.

Table of Contents

Title to Properties

Our properties are subject to customary royalty interests, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. We do not believe that any of these burdens materially interfere with our use of the properties in the operation of our business. We believe that we have generally satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, we make minimal investigation of title at the time we acquire undeveloped properties. We make title investigations and receive title opinions of local counsel only before we commence drilling operations. We believe that we have satisfactory title to all of our other assets. Although title to our properties is subject to encumbrances in certain cases, we believe that none of these burdens will materially detract from the value of our properties or from our interest therein or will materially interfere with the operation of our business.

Competition

The oil and natural gas industry is highly competitive and we compete with a substantial number of other companies that have greater resources. Many of these companies explore for, produce and market oil and natural gas, carry on refining operations and market the resultant products on a worldwide basis. The primary areas in which we encounter substantial competition are in locating and acquiring desirable leasehold acreage for our drilling and development operations, locating and acquiring attractive producing oil and gas properties, and obtaining transporters of the oil and gas we produce in certain regions. There is also competition between producers of oil and gas and other industries producing alternative energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the government of the United States; however, it is not possible to predict the nature of any such legislation or regulation that may ultimately be adopted or its effects upon our future operations. Such laws and regulations may, however, substantially increase the costs of exploring for, developing or producing gas and oil and may prevent or delay the commencement or continuation of a given operation. The effect of these risks cannot be accurately predicted.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. In particular, oil and natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate properties for oil and natural gas production have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas and that impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

The regulatory burden on the industry increases the cost of doing business and affects profitability. Failure to comply with applicable laws and regulations can result in substantial penalties. Furthermore, such laws and regulations are frequently amended or reinterpreted, and new proposals that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission, or FERC, and the courts. We believe we are in substantial compliance with all applicable laws and regulations, and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. Nor are we currently aware of any specific pending legislation or regulation that is reasonably likely to be enacted, or for which we cannot predict the likelihood of enactment, and that is reasonably likely to have a material effect on our financial position, cash flows or results of operations.

Regulation of transportation of oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of crude oil are affected by the availability, terms and cost of transportation. Interstate transportation of oil by pipeline is regulated by FERC pursuant to the ICA, EPAct 1992 and the rules and regulations promulgated under those laws. The ICA and its implementing regulations require that tariff rates for interstate service on oil pipelines, including interstate pipelines that transport crude oil and refined products (collectively referred to as "petroleum pipelines"), be just and reasonable and non-discriminatory and that such rates and terms and conditions of service be filed with FERC. EPAct 1992 deemed certain interstate petroleum pipeline rates then in effect to be just and reasonable under the ICA, which are commonly referred to as "grandfathered rates." Pursuant to EPAct 1992, FERC also adopted a generally applicable ratemaking methodology, which, as currently in effect and for the five year period beginning July 1, 2011, allows petroleum pipelines to change their rates provided they do not exceed prescribed ceiling levels that are tied to changes in the Producer Price Index for Finished Goods ("PPI"), plus 2.65%. The FERC order approving the currently effective index rate is subject to review by the Court of Appeals for the District of Columbia Circuit in *Valero Marketing Supply Co. v. FERC*, Case No. 11-1266 (D.C. Cir.).

FERC has also established cost-of-service ratemaking, market-based rates, and settlement rates as alternatives to the indexing approach. A pipeline may file rates based on its cost-of-service if there is a substantial divergence between its actual costs of providing service and the rate resulting from application of the index. A pipeline may charge market-based rates if it establishes that it lacks significant market power in the affected markets. Further, a pipeline may establish rates through settlement with all current non-affiliated shippers.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Regulation of transportation and sales of natural gas

Historically, the transportation and sale for resale of natural gas in interstate commerce has been regulated by the FERC under the Natural Gas Act of 1938 ("NGA"), the Natural Gas Policy Act of 1978 ("NGPA"), and regulations issued under those statutes. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead

Table of Contents

Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates, and terms and conditions of service, which affect the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued a series of orders, beginning with Order No. 636, to implement its open access policies. As a result, the interstate pipelines' traditional role of providing the sale and transportation of natural gas as a single service has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC's pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. In 2008, FERC issued Order No. 712, which removed price ceilings for short-term releases of one year or less and exempted from bidding and certain other conditions releases to asset managers who meet specified conditions.

Gathering services, which occur upstream of jurisdictional transmission services, are regulated by the states onshore and in state waters. Although the FERC has set forth a general test for determining whether facilities perform a nonjurisdictional gathering function or a jurisdictional transmission function, the FERC's determinations as to the classification of facilities is done on a case by case basis. To the extent that the FERC issues an order which reclassifies transmission facilities as gathering facilities, and depending on the scope of that decision, our costs of getting gas to point of sale locations may increase. State regulation of natural gas gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation and facilities are also subject to regulation by state regulatory agencies, and certain transportation services provided by intrastate pipelines are also regulated by FERC. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Market transparency rules

In 2007, FERC took steps to enhance its market oversight and monitoring of the natural gas industry by issuing several rulemaking orders designed to promote gas price transparency and to prevent market manipulation. In December 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing, or Order No. 704. Pursuant to Order No. 704, wholesale buyers and sellers of annual quantities of 2.2 million MMBtu or more of natural gas in the previous calendar year, including intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers, are required to report, by May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to, the formation of price indices. Order No. 704 also requires market participants to indicate whether they report prices to any index publishers and, if so, whether their reporting complies with FERC's policy statement on price reporting. Some of our operations may be required to comply with Order No. 704's annual reporting requirements.

In 2008, the FERC issued Order No. 720, which increases the Internet posting obligations of interstate pipelines, and also requires "major non-interstate" pipelines (defined as pipelines that are not natural gas companies under the NGA that deliver more than 50 million MMBtu annually and including gathering systems) to post on the Internet the daily volumes scheduled for each receipt and delivery point on their systems with a design capacity of 15,000 MMBtu per day or greater. Numerous parties requested modification or reconsideration of this rule. An order on rehearing, Order No. 720-A, was issued on January 21, 2010. In that order the FERC reaffirmed its holding that it has jurisdiction over major non-interstate pipelines for the purpose of requiring public disclosure of information to enhance market transparency. Order No. 720-A also granted clarification regarding application of the rule. Two parties have filed appeals of Order Nos. 720 and 720-A to the Fifth Circuit. On October 24, 2011, the Fifth Circuit issued its decision in *Texas Pipeline Association v. Federal Energy Regulatory Commission*, No. 10-60066 (5th Cir. filed Oct. 24, 2011), in which it vacated FERC Order Nos. 720 and 720-A on the basis that FERC did not have statutory authority under the NGA to require intrastate pipelines to disclose and disseminate capacity and scheduling information. It is not known whether FERC intends to seek rehearing of the decision by the Fifth Circuit or review of the decision by the United States Supreme Court or whether FERC intends to apply Order No. 720 to jurisdictions not within the jurisdiction of the Fifth Circuit. Unless the Fifth Circuit's decision is overturned, some or all of our operations that otherwise would have been required to comply with Order No. 720's posting requirements will not be required to do so.

In May 2010, the FERC issued Order No. 735, which requires intrastate pipelines providing transportation services under Section 311 of the NGPA and Hinshaw pipelines operating under Section 1(c) of the NGA to report on a quarterly basis more detailed transportation and storage transaction information, including: rates charged by the pipeline under each contract; receipt and delivery points and zones or segments covered by each contract; the quantity of natural gas the shipper is entitled to

Table of Contents

transport, store, or deliver; the duration of the contract; and whether there is an affiliate relationship between the pipeline and the shipper. Order No. 735 further requires that such information must be supplied through a new electronic reporting system and will be posted on FERC's website, and that such quarterly reports may not contain information redacted as privileged. The FERC promulgated this rule after determining that such transactional information would help shippers make more informed purchasing decisions and would improve the ability of both shippers and the FERC to monitor actual transactions for evidence of market power or undue discrimination. Order No. 735 also extends the Commission's periodic review of the rates charged by the subject pipelines from three years to five years. In December 2010, the Commission issued Order No. 735-A. In Order No. 735-A, the Commission generally reaffirmed Order No. 735 requiring section 311 and "Hinshaw" pipelines to report on a quarterly basis storage and transportation transactions containing specific information for each transaction, aggregated by contract.

In October 2010, the FERC issued a Notice of Inquiry seeking public comment on the issue of whether and how parties that hold firm capacity on some intrastate pipelines can allow others to use their capacity, including to what extent buy/sell transactions should permitted and whether the FERC should consider requiring such pipelines to offer capacity release programs. In the Notice of Inquiry, the FERC granted a blanket waiver regarding such transactions while the FERC is considering these policy issues. The comment period has ended but the FERC has not yet issued an order.

With regard to our physical sales of natural gas, we are required to observe anti-market manipulation laws and related regulations enforced by the FERC. The Energy Policy Act of 2005 ("EPAct 2005") amended the NGA to add an anti-manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-manipulation provision of EPAct 2005, and subsequently denied rehearing. The rule makes it unlawful for any entity, directly or indirectly, in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, (1) to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act, practice, or course of business that operates as a fraud or deceit upon any person. The anti-manipulation rules do not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but do apply to activities of gas pipelines and storage companies that provide interstate services, such as Section 311 service, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704.

With regard to our sales of petroleum and petroleum products, we are required to observe anti-market manipulations laws and related regulations enforced by the Federal Trade Commission ("FTC"). In addition, the CFTC has enforcement authority over market manipulation with respect to certain derivative contracts. Each of FERC, the FTC and the CFTC has the a power to asses fines of $1 million per day per violation of applicable anti-market manipulation laws and regulations. Should we violate anti-market manipulation laws and regulations, we could also be subject to third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

Table of Contents

Environmental, Health and Safety Regulation

Our exploration, development, production and processing operations are subject to various federal, state and local laws and regulations relating to health and safety, the discharge of materials and environmental protection. These laws and regulations may, among other things, require the acquisition of permits to conduct exploration, drilling and production operations; govern the amounts and types of substances that may be released into the environment in connection with oil and gas drilling and production; restrict the way we handle or dispose of our wastes; limit or prohibit construction or drilling activities in sensitive areas such as wetlands, wilderness areas or areas inhabited by endangered or threatened species; require investigatory and remedial actions to mitigate pollution conditions caused by our operations or attributable to former operations; and impose obligations to reclaim and abandon well sites and pits. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations and the issuance of orders enjoining some or all of our operations in affected areas.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, the Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal, cleanup and remediation requirements for the oil and gas industry could have a significant impact on our operating costs.

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment, and thus, any changes in environmental laws and regulations or re-interpretations of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal, or remediation requirements could have a material adverse effect on our operations and financial position in the future. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we cannot assure you that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons. We maintain insurance against costs of clean-up operations, but we are not fully insured against all such risks. While we believe that we are in substantial compliance with existing environmental laws and regulations and that current requirements would not have a material adverse effect on our financial condition or results of operations, there is no assurance that this will continue in the future.

The following is a summary of the more significant existing environmental, health and safety laws and regulations to which our business operations are subject and for which compliance in the future may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous substances and waste

CERCLA, also known as the Superfund law, and comparable state laws impose liability without regard to fault or the legality of the original conduct on certain classes of persons who are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include current and prior owners or operators of the site where the release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these "responsible persons" may be subject to strict, joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources, and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. 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

Table of Contents

hazardous substances or other pollutants into the environment. We generate materials in the course of our operations that may be regulated as hazardous substances.

We also generate solid and hazardous wastes that are subject to the requirements of the RCRA, as amended, and comparable state statutes. RCRA imposes requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. In the course of our operations we generate petroleum hydrocarbon wastes and ordinary industrial wastes that may be regulated as hazardous wastes. RCRA regulations specifically exclude from the definition of hazardous waste "drilling fluids, produced waters and other wastes associated with the exploration, development or production of crude oil, natural gas or geothermal energy." However, legislation has been proposed in Congress from time to time that would reclassify certain natural gas and oil exploration and production wastes as "hazardous wastes," which would make the reclassified wastes subject to much more stringent handling, disposal and clean-up requirements. If such legislation were to be enacted, it could have a significant impact on our operating costs, as well as the natural gas and oil industry in general.

We currently own or lease, and have in the past owned or leased, properties that have been used for numerous years to explore and produce oil and natural gas. Although we have utilized operating and disposal practices that were standard in the industry at the time, hydrocarbons and wastes may have been disposed of or released on or under the properties owned or leased by us or on or under the other locations where these hydrocarbons and wastes have been taken for treatment or disposal. In addition, certain of these properties have been operated by third parties whose treatment and disposal or release of hydrocarbons and wastes was not under our control. These properties and wastes disposed thereon may be subject to CERCLA, RCRA and analogous state laws. Under these laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators), to clean up contaminated property (including groundwater contaminated by prior owners or operators), and to perform remedial operations to prevent future contamination.

Pipeline safety and maintenance

Pipelines, gathering systems and terminal operations are subject to increasingly strict safety laws and regulations. Both the transportation and storage of refined products and crude oil involve a risk that hazardous liquids may be released into the environment, potentially causing harm to the public or the environment. In turn, such incidents may result in substantial expenditures for response actions, significant government penalties, liability to government agencies for natural resources damages, and significant business interruption. The U.S. Department of Transportation ("DOT") has adopted safety regulations with respect to the design, construction, operation, maintenance, inspection and management of our pipeline and storage facilities. These regulations contain requirements for the development and implementation of pipeline integrity management programs, which include the inspection and testing of pipelines and the correction of anomalies. These regulations also require that pipeline operation and maintenance personnel meet certain qualifications and that pipeline operators develop comprehensive spill response plans.

There have been recent initiatives to strengthen and expand pipeline safety regulations and to increase penalties for violations. New pipeline safety legislation requiring more stringent spill reporting and disclosure obligations has been introduced in the U.S. Congress and was passed by the U.S. House of Representatives in 2010, but was not voted on in the U.S. Senate. In December 2011, both Houses passed bipartisan legislation providing for more stringent oversight of pipelines and increased penalties for violations of safety rules. In addition, the Pipeline and Hazardous Materials Safety Administration announced an intention to strengthen its rules and recently promulgated new regulations extending safety rules to certain low pressure, small diameter pipelines in rural areas.

Table of Contents

Air emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws and regulations restrict the emission of air pollutants from many sources, including oil and gas operations, and impose various monitoring and reporting requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions. Obtaining permits has the potential to delay the development of oil and natural gas projects.

On August 20, 2010, the U.S. Environmental Protection Agency, or the EPA, published new regulations under the CAA to control emissions of hazardous air pollutants from existing stationary reciprocating internal combustion engines. The rule may require us to undertake certain expenditures and activities, likely including purchasing and installing emissions control equipment, such as oxidation catalysts or non-selective catalytic reduction equipment, on a portion of our engines located at major sources of hazardous air pollutants and all our engines over a certain size regardless of location, following prescribed maintenance practices for engines (which are consistent with our existing practices), and implementing additional emissions testing and monitoring. On October 19, 2010, industry groups submitted a legal challenge to the U.S. Court of Appeals for the D.C. Circuit and a Petition for Administrative Reconsideration to the EPA for some monitoring aspects of the rule. The legal challenge has been held in abeyance since December 3, 2010, pending the EPA's consideration of the Petition for Administrative Reconsideration. On January 5, 2011, the EPA approved the request for reconsideration of the monitoring issues and on March 9, 2011, the EPA issued a new proposed rule and a direct final rule effective on May 9, 2011 to clarify compliance requirements related to operation and maintenance procedures for continuous parametric monitoring systems. At this point, we cannot predict whether the reconsideration request and court proceedings will result in modifications to the final rule. Compliance with the final rule currently is required by October 2013.

On June 28, 2011, the EPA issued a final rule, effective August 29, 2011, modifying existing regulations under the CAA that established new source performance standards for manufacturers, owners and operators of new, modified and reconstructed stationary internal combustion engines. Those new requirements may increase our costs of buying and operating such engines. Compliance with the final rule would not be required until at least 2013.

On July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's proposed rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The proposed rules also would establish specific new requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. In addition, the rules would establish new leak detection requirements for natural gas processing plants. The EPA is accepting public comment on the proposed rules and must take final action on the rules by April 3, 2012. If finalized, these rules could require modifications to our operations or increase our capital and operating costs without being offset by increased product capture. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements.

Climate change

The United States is a party to the United Nations Framework Convention on Climate Change, an international treaty focused on stabilizing GHG concentrations in the atmosphere at a level that would prevent serious damage to the climate system. While neither the treaty itself, nor subsequent related conferences, have established an obligation for the U.S. to reduce its GHG emissions by a set amount, it

Table of Contents

has put significant political pressure on the U.S. to take responsive action. Both houses of Congress have previously considered legislation to reduce emissions of GHG. Any future federal laws, treaties or implementing regulations that may be adopted to address GHG emissions could require us to incur increased operating costs and could adversely affect demand for the oil and natural gas we produce.

In addition, the EPA has begun to regulate GHG emissions. In December 2009, the EPA published its finding that certain emissions of GHG presented an endangerment to human health and the environment. These findings by the EPA allow the agency to proceed with the adoption and implementation of regulations that would restrict emissions of GHG under existing provisions of the federal Clean Air Act. Consequently, the EPA is requiring a reduction in emissions of GHG from new motor vehicles beginning with the 2012 model year. Furthermore, the EPA published a final rule on June 3, 2010 to address the permitting of GHG emissions from stationary sources under the Prevention of Significant Deterioration and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of GHG emissions, such as power plants and oil refineries, in a multi-step process, with the largest sources first subject to permitting. Facilities required to obtain PSD permits for their GHG emissions will be required to meet emissions limits that are based on the "best available control technology," which will be established by the permitting agencies on a case-by-case basis. Starting in January 2011, stationary sources that are already obtaining a Clean Air Act permit for other pollutants must include GHG in their permits if they emit at least 75,000 tons of these emissions per year. In July 2012, the rule expands to include all new facilities that emit at least 100,000 tons of GHG per year.

In addition, in October 2009, the EPA issued a final rule requiring the reporting of GHG from specified large GHG emission sources beginning in 2011 for emissions in 2010. Our McKamie processing facility in Arkansas is currently required to report under this rule this year. On November 30, 2010, the EPA published a final rule expanding the existing GHG monitoring and reporting rule to include certain large onshore and offshore oil and gas production facilities and onshore oil and natural gas processing, transmission, storage and distribution facilities. Reporting of GHG emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. Our McKamie processing facility and our North Park Basin, Colorado facility are currently required to report under this rule. The EPA also published a final rule requiring reporting for natural gas liquid fractionators, which applies to the McKamie processing facility and a separate reporting rule for suppliers of carbon dioxide, which affects our operations in the North Park Basin. Several of the EPA's GHG rules are being challenged in court proceedings and depending on the outcome of such proceedings, such rules may be modified or rescinded or the EPA could develop new rules. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of GHG from, our equipment and operations could require us to incur costs to reduce emissions of GHG associated with our operations or could adversely affect demand for the oil and natural gas we produce.

Even if such legislation is not adopted at the national level, almost one-half of the states have begun taking actions to control and/or reduce emissions of GHG, primarily through the planned development of GHG emission inventories and/or GHG cap and trade programs. For example, California's cap and trade regulations are scheduled to take effect on January 1, 2012, with enforcement expected to begin in 2013, which will allow the State to refine the requirements in the interim. Although most of the state-level initiatives have to date focused on large sources of GHG emissions, such as coal-fired electric plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations or allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

Legislation or regulations that may be adopted to address climate change could also affect the markets for our products by making our products more or less desirable than competing sources of energy. To the extent that our products are competing with higher GHG emitting energy sources such as coal, our products would become more desirable in the market with more stringent limitations on GHG emissions. To the extent that our products are competing with lower GHG emitting energy sources such as solar and wind, our products would become less desirable in the market with more stringent limitations on GHG emissions. We cannot predict with any certainty at this time how these possibilities may affect our operations.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHG in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such effects were to occur, they could adversely affect or delay demand for the oil or natural gas or otherwise cause us to incur significant costs in preparing for or responding to those effects.

Water discharges

The Federal Water Pollution Control Act, as amended, or the Clean Water Act ("CWA"), and analogous state laws impose restrictions and controls regarding the discharge of pollutants into waters of the United States. Pursuant to the CWA and analogous state laws, permits must be obtained to discharge pollutants into state waters or waters of the U.S. The CWA and regulations implemented thereunder also prohibit the discharge of dredge and fill material into regulated waters, including jurisdictional wetlands, unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. Federal and state regulatory agencies can impose administrative, civil and criminal penalties as well as other enforcement mechanisms for non-compliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

Endangered Species Act

The federal Endangered Species Act, as amended, ("ESA") restricts activities that may affect endangered and threatened species or their habitats. While some of our facilities may be located in areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

Employee health and safety

We are subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act, as amended (the "OSH Act"), and comparable state statutes, whose purpose is to protect the health and safety of workers. In addition, the OSH Act's hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Hydraulic fracturing

Regulations relating to hydraulic fracturing. The federal Safe Drinking Water Act ("SDWA"), and comparable state statutes may restrict the disposal, treatment or release of water produced or used during oil and gas development. Subsurface emplacement of fluids (including disposal wells or enhanced oil recovery) is governed by federal or state regulatory authorities that, in some cases, include the state oil and gas regulatory or the state's environmental authority. The federal Energy Policy Act of 2005 amended the

Table of Contents

Underground Injection Control, or UIC, provisions of the SDWA to expressly exclude certain hydraulic fracturing from the definition of "underground injection." However, the U.S. Senate and House of Representatives are currently considering bills entitled the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the SDWA to repeal this exemption. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process. If the exemption for hydraulic fracturing is removed from the SDWA, or if the FRAC Act or other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition and results of operations.

Federal agencies are also considering regulation of hydraulic fracturing. The EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA's Underground Injection Control Program. While the EPA has yet to take any action to enforce or implement this newly asserted regulatory authority, the EPA's interpretation without formal rule making has been challenged and industry groups have filed suit challenging the EPA's interpretation. If the EPA prevails in this lawsuit, its interpretation could result in enforcement actions against service providers or companies that used diesel products in the hydraulic fracturing process or could require such providers or companies to conduct additional studies regarding diesel in groundwater. In addition, on October 21, 2011, the EPA announced its intention to propose regulations by 2014 under the federal Clean Water Act to regulate wastewater discharges from hydraulic fracturing and other natural gas production. The EPA is also collecting information as part of a study into the effects of hydraulic fracturing on drinking water. The results of this study, expected in late 2012, could result in additional regulations, which could lead to operational burdens similar to those described above. The United States Department of the Interior has also announced its intention to propose a new rule regulating hydraulic fracturing activities on federal lands, including requirements for disclosure, well bore integrity and handling of flowback water.

Several state governments in the areas where we operate have adopted or are considering adopting additional requirements relating to hydraulic fracturing that could restrict its use in certain circumstances or make it more costly to utilize. Such measures may address any risk to drinking water, the potential for hydrocarbon migration and disclosure of the chemicals used in fracturing. For example, the State of Colorado, in response to an EPA request, has asked other companies operating in Colorado to report whether diesel products were used in the hydraulic fracturing process from 2004 to 2009. The State of Colorado may conduct additional investigations related to this inquiry. Any enforcement actions or requirements of additional studies or investigations by governmental authorities where we operate could increase our operating costs and cause delays or interruptions of our operations.

At this time, it is not possible to estimate the potential impact on our business of these state and local actions or the enactment of additional federal or state legislation or regulations affecting hydraulic fracturing.

Our use of hydraulic fracturing. We use hydraulic fracturing as a means to maximize production of oil and gas from formations having low permeability such that natural flow is restricted. Fracture stimulation has been used for decades in both the Rocky Mountains and Mid Continent. In the Rocky Mountains, other companies in the oil and gas industry have fracture stimulated tens of thousands of wells since the mid 1980s. We and our predecessor companies have completed over 300 fracture stimulations since acquiring assets in the DJ Basin in 1999. At our Dorcheat Macedonia property in the Mid-Continent region, fracture stimulation has been performed since the 1970s and has been used more universally since the early 1990s. We and our predecessor companies have completed over 40 fracture stimulations since acquiring our Dorcheat Macedonia properties in mid-2008.

Table of Contents

We expect that approximately 91% of our total acreage held as of December 31, 2010 will be subject to hydraulic fracturing in one or more reservoirs, which corresponds to approximately 44% of our total proved reserves. Our use of hydraulic fracturing is limited mainly to our Mid-Continent and Rocky Mountain regions. Although the cost of each well varies, costs incurred in connection with hydraulic fracturing activities as a percentage of the total cost of drilling and completing a new-drill well average approximately 21% (or $350,000) in our Mid-Continent region and 46% (or $385,000) in our Rocky Mountain region. These costs are accounted for in the same way that all other costs of drilling and completing our wells are accounted for and are included in our normal capital expenditure budget, which is funded through operating cash flows or borrowings under our credit facility. Based on the expected capital forecast in our proved reserve report, we estimate that we will spend approximately $93.1 million for future fracturing activities on both new-drill wells and workovers on existing wells.

For as long as we have owned and operated properties subject to hydraulic fracturing, there have not been any incidents, citations or suits related to fracturing operations or related to environmental concerns from fracturing operations.

We periodically review our plans and policies regarding oil and gas operations, including hydraulic fracturing, in order to minimize any potential environmental impact. We adhere to applicable legal requirements and industry practices for groundwater protection. Our operations are subject to close supervision by state and federal regulators (including the Bureau of Land Management with respect to federal acreage), who frequently inspect our fracturing operations.

During well construction, steel casing pipe and concrete are employed for protection. Once the pipe is set in place, cement is pumped into the well where it hardens to create an isolating barrier between the steel casing pipe and the surrounding geological formations. In accordance with best industry practices, casing and cement design conforms to the applicable requirements and standards of state agencies. As an example, for any fresh water aquifers, a separate string of casing is set below the base as part of the casing design to eliminate any "pathway" for the fracturing fluid to contact any fresh water aquifers during the hydraulic fracturing operations. Furthermore, the hydrocarbon bearing formations are generally separated from any usable underground fresh water aquifers by thousands of feet of impermeable rock layers. This distance is approximately 5,200 feet and 6,200 feet, respectively, for our Rockies and Mid-Continent reservoirs that are being fracture stimulated. This wide separation serves as a protective barrier that prevents any migration of fracturing fluids or hydrocarbons upwards into any groundwater zones. In addition, the vendors conducting hydraulic fracturing on our properties monitor pump rates and pressures during the fracturing treatments. This monitoring occurs on a real-time basis to identify abrupt changes in rate or pressure, which permits the operator to modify or cease the fracturing process.

Typical hydraulic fracturing treatments are made up of water, chemical additives and sand. We utilize major hydraulic fracturing service companies who track and report all additive chemicals that are used in fracturing as required by the appropriate government agencies. Each of these companies fracture stimulate a multitude of wells for the industry each year.

We strive to minimize water usage in our fracture stimulation designs. Water recovered from our hydraulic fracturing operations is disposed of in a way that does not impact surface waters. We dispose of our recovered water by means of approved disposal or injection wells.

Surface spills and leaks are controlled, contained and remediated in accordance with the applicable requirements of state oil and gas commissions, as well as any Spill Prevention, Control and Countermeasures (SPCC) plans we maintain in accordance with EPA requirements. This would include any action up to and including total abandonment of the wellbore.

Table of Contents

Other laws

The Oil Pollution Act of 1990, as amended, ("OPA") establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the U.S. The OPA assigns liability to each responsible party for oil cleanup costs and a variety of public and private damages. While liability limits apply in some circumstances, a party cannot take advantage of liability limits if the spill was caused by gross negligence or willful misconduct or resulted from violation of a federal safety, construction or operating regulation. If the party fails to report a spill or to cooperate fully in the cleanup, liability limits likewise do not apply. Few defenses exist to the liability imposed by the OPA. The OPA imposes ongoing requirements on a responsible party, including the preparation of oil spill response plans and proof of financial responsibility to cover environmental cleanup and restoration costs that could be incurred in connection with an oil spill.

The National Environmental Policy Act of 1969, as amended ("NEPA"), requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment before their commencement. Generally, federal agencies must prepare either an environmental assessment or an environmental impact statement depending on whether the specific circumstances surrounding the proposed federal action will have a significant impact on the environment. The NEPA process involves public input through comments which can alter the nature of a proposed project either by limiting the scope of the project or requiring resource-specific mitigation. NEPA decisions can be appealed through the administrative and federal court systems by process participants. Although we believe that our actions do not typically trigger NEPA analysis, should we ever be subject to NEPA, the process may result in delaying the permitting and development of projects, increase the costs of permitting and developing some facilities and could result in certain instances in the cancellation of certain leases.

Our properties located in Colorado are subject to the authority of the Colorado Oil and Gas Conservation Commission, or COGCC. The COGCC recently approved new rules governing oil and gas activity which are intended to prevent or mitigate environmental impacts of oil and gas development and include the permitting of wells. Depending on how these and any other new rules are applied to our operations, they could add substantial increases in well costs in our Colorado operations. The rules could also impact the ability and extend the time necessary to obtain drilling permits, which would create substantial uncertainty about our ability to meet future drilling plans and thus production and capital expenditure targets.

Employees

At October 31, 2011, we had approximately 71 full-time employees. None of our employees is represented by a labor union or covered by any collective bargaining agreement. We believe that our relations with our employees are satisfactory.

Legal Proceedings

From time to time, we are subject to legal proceedings and claims that arise in the ordinary course of business. Like other gas and oil producers and marketers, our operations are subject to extensive and rapidly changing federal and state environmental, health and safety and other laws and regulations governing air emissions, wastewater discharges, and solid and hazardous waste management activities. As of the date of this prospectus, there are no material pending or overtly threatened legal actions against us that we are aware of.

Frank H. Bennett, a co-manager of BCOC and former chairman of BCEC, has made a demand for arbitration against Michael R. Starzer, our President and Chief Executive Officer, focusing on

Table of Contents

Mr. Starzer's handling of the operation, accounting and finances of BCOC and BCEC primarily during the 2005-2006 period. Mr. Bennett's demands do not allege any wrongdoing by or claims against Bonanza Creek Energy, Inc. There can be no assurance as to the ultimate outcome of the arbitration proceedings.

Our Board of Directors formed a Special Litigation Committee comprised of three non-executive directors to conduct an investigation of these allegations. The Special Litigation Committee retained outside independent advisors and conducted an in-depth investigation. The Special Litigation Committee concluded that neither it nor its legal or financial advisors had found any evidence to support any of Mr. Bennett's allegations. The Board thereby concluded that the allegations against Mr. Starzer are unsubstantiated and lack merit.

Insurance Matters

As is common in the oil and gas industry, we will not insure fully against all risks associated with our business either because such insurance is not available or because premium costs are considered prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our financial position, results of operations or cash flows.

Table of Contents

MANAGEMENT

The following table sets forth information regarding our directors and executive officers as of the date of this prospectus and upon completion of the offering. There are no family relationships among any of our directors or executive officers.

Name	Age	Position
Michael R. Starzer	50	Director, President and Chief Executive Officer
James R. Casperson	64	Executive Vice President and Chief Financial Officer
Gary A. Grove	51	Director, Executive Vice President Engineering and Planning, Interim Chief Operating Officer
Patrick A. Graham	50	Executive Vice President Corporate Development
Richard J. Carty	42	Chairman of the Board
Marvin Chronister	60	Director
Kevin A. Neveu	51	Director
Todd A. Overbergen	46	Director
Gregory P. Raih	64	Director

Michael R. Starzer is a member of our board of directors and is our President and Chief Executive Officer. Mr. Starzer was a founder and co-manager of Bonanza Creek Oil Company, LLC, and served as a member of the board of managers and President and Chief Executive Officer of our predecessor BCEC since BCEC's formation in 2006. Mr. Starzer has over 28 years of experience in the oil and gas industry. Mr. Starzer has served in numerous positions in the oil and gas industry evaluating and developing oil, gas, electricity and geothermal resources. From 1983 to 1991, Mr. Starzer was employed by Unocal in various engineering and supervisory positions. From 1991 until 1993, Mr. Starzer served with the California State Lands Commission as Statewide Petroleum Reservoir Engineer and worked as a private consultant to the energy industry supervising operations and appraisals of oil, gas and geothermal resources on properties throughout the United States. In 1993, Mr. Starzer returned to Unocal as an Asset Manager assisting them with the sale and management of certain assets. Starting in 1995, Mr. Starzer served as an Officer, Manager and Vice President of Berry Petroleum until beginning his tenure with one of our predecessors in 1999. Mr. Starzer holds a degree in Petroleum Engineering from the Colorado School of Mines and a Master of Science degree in Engineering Management from the University of Alaska and is a registered professional engineer in petroleum engineering. We believe Mr. Starzer's extensive experience in the oil and gas industry, his leadership positions at other oil and gas companies and his knowledge regarding our business and operations bring important experience and leadership to our company and our board of directors.

James R. Casperson was appointed Executive Vice President and Chief Financial Officer effective as of October 31, 2011. He previously served on our board of directors beginning in March of 2011. Mr. Casperson has over 42 years of experience in the oil and gas industry and finance and accounting in the public and private sectors. Prior to joining us, Mr. Casperson was a private consultant to the energy industry. From 2005 until 2008, he was the Chief Financial Officer of Ellora Energy and, from 2000 until 2005, the Chief Financial Officer of Whiting Petroleum Corporation. Before joining Whiting, Mr. Casperson spent 15 years as President of Casperson Incorporated, a private consulting firm specializing in the energy industry. Mr. Casperson holds a BBA in Accounting from Texas Tech University.

Gary A. Grove is a member of our board of directors and is our Executive Vice President Engineering and Planning and Interim Chief Operating Officer. Mr. Grove joined Bonanza Creek Oil Company in March 2003 and served as a member of the board of managers and as Executive Vice President and Chief Operating Officer of BCEC. Mr. Grove has over 29 years of experience in the oil and gas industry serving in reservoir engineering and management positions with Unocal and Nuevo Energy prior to joining us. Mr. Grove graduated from Marietta College in 1982 with a Bachelor of Science degree in Petroleum Engineering. Mr. Grove is an active member with the Society of Petroleum Engineers and has served in

Table of Contents

various capacities for student and local chapters since 1979. We believe Mr. Grove's extensive experience in the oil and gas industry and his knowledge regarding our business and operations brings important experience and leadership to our board of directors.

Patrick A. Graham joined Bonanza Creek Oil Company in November 2001, served as a Senior Vice President of BCEC and currently serves as our Executive Vice President Corporate Development. From 1995 to 2001, Mr. Graham was employed by Berry Petroleum Company where he evaluated acquisition opportunities in California, the Rocky Mountain region and Canada. Mr. Graham gained experience working with major and independent oil companies while employed with Dowell Schlumberger from 1986 to 1995. Mr. Graham received his Bachelors of Science degree in Petroleum Engineering from Texas A&M University and has held various technical positions in Utah, Colorado, New Mexico, California and Alaska.

Richard J. Carty was elected to our board of directors in December 2010 and is President of West Face Capital (USA) Corp, an affiliate of West Face Capital, a Toronto-based investment management firm, and has served on the board of directors of portfolio companies on behalf of West Face Capital. Prior to that time, Mr. Carty was a Managing Director of Morgan Stanley Principal Strategies in New York where he led the Special Situations, Strategic Investments, and Global Quantitative Equity investment teams. Mr. Carty was at Morgan Stanley & Co. for 14 years in New York, and prior to that time was a partner at Gordon Capital Corp, a private Toronto-based investment bank for five years. We believe Mr. Carty's extensive asset management, capital markets, investment banking, and private equity experience bring important and valuable skills to our board of directors.

Marvin Chronister was elected to our board of directors in March 2011. Mr. Chronister has over 30 years experience in the oil and gas industry. Mr. Chronister is currently an independent investor, energy finance and operations consultant for Enfield Companies and on the board of directors of Sonde Resources Corp. From 2004 until 2006, Mr. Chronister was the Financial Operations Practice Director of Jefferson Wells International, Inc. He served as Managing Director of Corporate Finance for Deloitte & Touche from 1990 to 2003 with previous positions in industry and investment banking. Mr. Chronister holds a Bachelor of Business Administration degree from Stephen F. Austin State University. We believe Mr. Chronister's extensive experience in the oil and gas industry as well as his financial and accounting experience bring important and valuable skills to our board of directors.

Kevin A. Neveu was elected to our board of directors in March 2011. Mr. Neveu has over 25 years of experience in the oil and gas industry. Currently, Mr. Neveu serves as a director, President and Chief Executive Officer of Precision Drilling Corporation. Mr. Neveu was previously President of the Rig Solutions Group of National Oilwell Varco, where he was responsible for the company's drilling equipment business. Beginning in 1982, Mr. Neveu held senior management positions with National Oilwell Varco and its predecessor companies in London, Moscow, Houston, Edmonton and Calgary. Mr. Neveu holds a Bachelor of Science degree and is a graduate of the Faculty of Engineering at the University of Alberta. Mr. Neveu is a Professional Engineer, as designated by the Association of Professional Engineers, Geologists and Geophysicists of Alberta and has attended the Advanced Management Program at the Harvard Business School. Mr. Neveu serves on the boards of RigNet Inc., the Heart and Stroke Foundation of Alberta and the International Association of Drilling Contractors. We believe Mr. Neveu's extensive experience in the oil and gas industry as well as his experience on the boards of directors of public energy companies bring substantial leadership and experience to our board of directors.

Todd A. Overbergen has served on the board of directors of our predecessor, BCEC, since 2008. Mr. Overbergen joined the D. E. Shaw Group in February 2004 and is Head of Energy and a Director in the Direct Capital Unit of the D. E. Shaw Group. From December 2000 to April 2003, Mr. Overbergen was a principal at Duke Capital Partners LLC, a merchant banking subsidiary of Duke Energy Corporation that provided mezzanine, equity, and senior debt capital to the energy industry. From 1998 to December 2000, Mr. Overbergen was a director in Arthur Andersen LLP's Global Corporate Finance group, where he co-led the national business services practice and provided investment banking services on mergers,

Table of Contents

acquisitions, and private market capital raising of debt and equity. Mr. Overbergen serves on the board of directors of numerous existing D. E. Shaw Group portfolio companies and has served on the board of directors of several previous portfolio companies of the D. E. Shaw Group and Duke Capital Partners LLC. Mr. Overbergen is a member of the Houston Producers Forum and Independent Petroleum Association of America. Mr. Overbergen holds two Bachelor of Business Administration degrees in finance and accounting from Texas A&M University. We believe Mr. Overbergen's extensive financial, accounting, merchant banking and private equity experience, as well as his extensive experience in the energy sector, bring important and valuable skills to our board of directors.

Gregory P. Raih was elected as a member of our board of directors in November 2011. Mr. Raih has nearly 40 years of experience in finance and accounting in the public and private sectors and extensive experience with the oil and gas industry. Mr. Raih currently serves on the board of directors of General Moly, Inc. (AMEX: GMO), a U.S.-based mineral company engaged in the exploration, development and mining of molybdenum. Mr. Raih served as partner at KPMG LLP from 2002 to 2008 and held a variety of roles as partner at Arthur Andersen LLP from 1981 to 2002. He served in the energy practice of both firms as the engagement partner on a number of clients in the oil and gas industry, including Cordillera Energy, Delta Petroleum and Red Willow Production. Mr. Raih is a graduate of the University of Notre Dame. He is also a member of the American Institute of Certified Public Accountants and the Colorado Society of Certified Public Accountants. We believe that Mr. Raih's financial and accounting experience, as well as his broad experience with the oil and gas industry, brings important and valuable skills to our board of directors.

Board of Directors

Our board of directors currently consists of seven members, including our President and Chief Executive Officer and our Executive Vice President Engineering and Planning and Interim Chief Operating Officer. Each of our current directors has significant industry experience.

Our board has reviewed the independence of our current directors using the independence standards of the NYSE and has determined that Messrs. Chronister, Neveu, Overbergen and Raih are independent based on such standards. Thus, our board of directors is currently comprised of a majority of independent directors.

We expect that our audit, compensation and nominating and governance committees will consist entirely of independent directors within one year following the effective date of this registration statement. Each of these committees has a written charter addressing such committee's purpose and responsibilities.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board's ability to manage and direct the affairs and business of the company, including, when applicable, to enhance the ability of committees of the board to fulfill their duties.

Commencing with the 2012 annual meeting of our stockholders, our directors will be divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of stockholders in 2013, 2014 and 2015, respectively. At each annual meeting of stockholders held after the initial classification, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of stockholders will be necessary for stockholders to effect a change in a majority of the members of the board of directors.

Table of Contents

Committees of the Board of Directors

Our board of directors currently has an audit committee, nominating and governance committee, compensation committee, reserve committee and environmental safety and regulatory compliance committee, and will have a nominating and governance committee upon consummation of this offering, and may have such other committees as the board of directors shall determine from time to time. Each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

The members of our audit committee are Messrs. Raih (Chairman), Carty and Chronister, each of whom our board of directors has determined is financially literate. Our board of directors has determined that Messrs. Raih and Chronister are audit committee financial experts and are "independent" under the standards of the NYSE and SEC regulations. This committee oversees, reviews, acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have adopted an audit committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Compensation Committee

The members of our compensation committee are Messrs. Carty (Chairman), Neveu and Overbergen. Our board of directors has determined that Messrs. Neveu and Overbergen are independent under the standards of the NYSE and SEC regulations. This committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee also administers our incentive compensation and benefit plans. We have adopted a compensation committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Nominating and Corporate Governance Committee

The members of our nominating and governance committee are Messrs. Carty (Chairman), Raih and Chronister. Our board of directors has determined that Messrs. Chronister and Raih are independent under the standards of the NYSE and SEC regulations. This committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan. We have adopted a nominating and governance committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and NYSE or market standards.

Reserve Committee

The members of the reserve committee are Messrs. Chronister (Chairman), Carty and Overbergen. Our reserve committee oversees, reviews, acts on and reports on our reserve engineering reports and reserve engineers to our board. Our reserve committee is responsible for (i) the integrity of our reserve reports, (ii) determinations regarding the qualifications and independence of our independent reserve engineers, (iii) the performance of our independent reserve engineers and (iv) our compliance with certain legal and regulatory requirements.

Table of Contents

Environmental Safety and Regulatory Compliance Committee

The members of the environmental safety & regulatory compliance ("ES&RC") committee are Messrs. Chronister (Chairman), Neveu and Grove. Our ES&RC committee's primary purpose is to assist our board of directors in fulfilling our responsibilities to provide global oversight and support of the Company's environmental safety, regulatory and compliance policies, programs and initiatives. In carrying out its responsibilities, the ES&RC committee reviews the status of our health, safety and environmental performance, including processes monitoring and reporting on compliance with internal policies and goals and applicable laws and regulations.

Compensation Committee Interlocks and Insider Participation

No member of our compensation committee has been at any time an employee of ours. During the past fiscal year, none of our executive officers serve or has served on the board of directors or compensation committee of a company that has one or more executive officers who serve on our board of directors or compensation committee. No member of our board of directors is an executive officer of a company in which one or more of our executive officers serves as a member of the board of directors or compensation committee of that company.

To the extent any members of our compensation committee and affiliates of theirs have participated in transactions with us, a description of those transactions is described in "*Certain Relationships and Related Party Transactions*."

Code of Business Conduct and Ethics

Our board of directors has adopted a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our board of directors or a committee of our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE.

Corporate Governance Guidelines

Our board of directors has adopted corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

Table of Contents

EXECUTIVE COMPENSATION AND OTHER INFORMATION

Compensation Discussion and Analysis

This compensation discussion and analysis, or CD&A, provides information about our compensation objectives and policies for our principal executive officer, our principal financial officer and our other three most highly compensated executive officers at the end of the last completed fiscal year, and is intended to place in perspective the information contained in the executive compensation tables that follow this discussion. This CD&A provides a general description of our compensation program and information about its various components.

Throughout this discussion, the following individuals are referred to as the "named executive officers" and are included in the Summary Compensation Table:

- Michael R. Starzer, President and Chief Executive Officer;
- James R. Casperson, Executive Vice President and Chief Financial Officer;
- Steven B. Wilson, our former Vice President and Chief Accounting Officer;
- C. Stephen Black, our former Executive Vice President and Chief Operating Officer;
- Gary A. Grove, Executive Vice President Engineering and Planning and Interim Chief Operating Officer; and
- Patrick A. Graham, Executive Vice President Corporate Development.

Mr. Casperson was appointed Executive Vice President and Chief Financial Officer effective as of October 31, 2011. Information regarding Mr. Casperson's compensation is included in this CD&A because he will be a named executive officer for 2011 and thereafter.

Steven R. Enger joined our company on June 13, 2011 as our Executive Vice President and Chief Financial Officer and resigned effective October 31, 2011 to pursue other opportunities. While he was employed by us, he received a total of $112,823.17 in cash compensation as salary. Prior to his employment with us, Mr. Enger served as a consultant to us for which he was paid $25,000 in 2011. Upon joining us, Mr. Enger was granted 600 shares of our Class B Common Stock that were forfeited upon his resignation and separation from the company. Pursuant to his employment agreement with us, Mr. Enger was not entitled to any severance compensation.

Mr. Wilson resigned his position as Vice President and Chief Accounting Officer effective as of September 2, 2011 to pursue other opportunities. Information regarding Mr. Wilson's compensation is included in this CD&A and the accompanying tables and narrative sections because he was one of our named executive officers during our last completed fiscal year. Mr. Wilson received severance compensation of $210,000. He also received 9,216 shares of our Class A Common Stock in exchange for a full release of the company. We do not intend to hire a replacement Chief Accounting Officer. Our Controller, Wade E. Jaques, became our principal accounting officer upon Mr. Wilson's departure.

Mr. Black resigned his position as Chief Operating Officer on May 20, 2011 to spend more time with his family. Information regarding Mr. Black's compensation is included in this CD&A and the accompanying tables and narrative sections because he was one of our named executive officers during our last completed fiscal year. Our board of directors has appointed Mr. Grove to serve as interim Chief Operating Officer and has authorized a search committee comprised of three directors to identify qualified candidates to serve as our Chief Operating Officer. We expect that our board of directors will thoroughly assess all candidates presented by the search committee and will appoint a permanent Chief Operating Officer as soon as practicable.

Table of Contents

Although the information presented in this CD&A focuses on our fiscal year 2010, we also describe compensation actions taken before or after fiscal year 2010 to the extent such discussion enhances the understanding of our executive compensation disclosure.

Compensation Program Philosophy and Objectives

The objective of our compensation program is to attract, retain and motivate the most qualified individuals in the oil and gas industry whom we can identify and recruit. Our compensation program is designed to reward employees for performance that creates long-term stockholder value by successfully implementing our long-term strategy and achieving our short-term goals. We strive to create a compensation program that encourages long-term value creation by tying individual compensation to the attainment of our annual performance targets while acknowledging and fostering the unique qualifications, skills, experience and responsibilities of each individual.

For 2010, as a private company, we did not have a compensation committee, compensation consultant or formally set peer group, however, our compensation was set based on our board of directors' and management's assessment of a variety of factors, including industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company. For 2011, we have begun to establish more formal compensation standards using compensation levels at or near the market midpoint, or 50th percentile as a guideline in establishing our compensation levels, although we may deviate from the 50th percentile for individual considerations such as experience, tenure and job responsibilities. The "market" consists of the average of (i) compensation data for our peer group and (ii) compensation data from published surveys. While historically long term incentives have played a relatively small role in the annual compensation of our named executive officers, after this offering, consistent with our philosophy of setting compensation levels at or near the market 50th percentile, we intend to utilize our newly adopted Long-term Incentive Plan. See "*Elements of Compensation and Why We Pay Each Element Long-term Incentives*" below. Under this Long-term Incentive Plan, we expect that a significant portion of our named executive officers' overall compensation will be made up of long-term incentives. The average portion of total compensation paid as long-term incentives for the named executive officers at the market 50th percentile is approximately 40%. For 2011, the compensation for all named executive officers is reviewed and determined by our compensation committee, subject to the approval of our board of directors. In addition to actual job responsibility and competitive market data, we give consideration to individual performance of the named executive officer and internal pay equity relative to our other executive officers. Under the direction of our compensation committee and subject to the approval of our board, salaries are generally reviewed annually as part of our performance review process.

Setting Executive Officer Compensation

The Role of Our Compensation Committee: For 2010 and prior years, as a private company, our board of directors and management set executive officer compensation taking into account a variety of factors, including industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company. For the fiscal year 2010, we did not have a compensation committee. Our board of directors established the compensation committee in March 2011 and authorized the committee to review and propose for approval by our board of directors the compensation for our Section 16(b) executives. Our compensation committee (i) oversees our compensation programs on behalf of our board of directors; (ii) is responsible for proposing programs for approval by our board of directors that attract, retain and motivate qualified executive-level talent; and (iii) monitors our compensation programs and strives to ensure that the total compensation paid to the named executive officers is fair, reasonable and competitive with that provided to executive officers serving in similar roles and with similar responsibilities in other U.S. publicly traded energy companies.

Table of Contents

The Role of the Compensation Consultant: For the fiscal year 2011, Longnecker & Associates (the "Compensation Consultant") was engaged on behalf of the compensation committee as our compensation committee's independent compensation consultant. Our predecessor did not engage a compensation consultant. Our compensation committee felt it was beneficial to have an independent third-party analysis to assist in evaluating and setting executive compensation. Our compensation committee chose the Compensation Consultant because our compensation committee believes the Compensation Consultant has extensive experience in providing executive compensation advice, including specific experience in the oil and gas industry. The Compensation Consultant provided our compensation committee with an analysis of our executive compensation programs, including total direct compensation comprised of base salary, annual incentive and long-term incentive compensation, in order to assess the competitiveness of our programs and to provide conclusions and recommendations. For the fiscal year 2011, our compensation committee has taken and will take into consideration the discussions, guidance and compensation studies produced by the Compensation Consultant in order to make compensation decisions. The Compensation Consultant does not provide to us any services or advice on matters unrelated to executive and independent director compensation and reports directly to and takes direction from our compensation committee, which has the authority to engage or terminate the Compensation Consultant in its discretion. Our compensation committee has determined that the advice provided by the Compensation Consultant relating to executive compensation was free from any relationships that could impair the professional advice or compromise the integrity of the information or data provided to our compensation committee.

Competitive Benchmarking and Peer Group: Our compensation committee considers competitive industry data in making executive pay determinations. Pursuant to our compensation committee's decision to maintain a peer group for compensation purposes and in view of evolving industry and competitive conditions, the Compensation Consultant proposed certain peer group companies for our compensation committee's review. As a private company, neither we nor our predecessor utilized a formal peer group, but our board of directors and management considered industry information and performance, an individual's rank, tenure, experience and job responsibilities and the performance of our company in setting compensation.

After discussions with the Compensation Consultant and reviewing the Compensation Consultant's recommendation of a peer group based on companies with annual revenue, assets, and net income similar to ours taking into account geographic footprint and employee count, our compensation committee determined that the peer group listed below is the most appropriate for purposes of executive compensation analyses. The Compensation Consultant compiled compensation data for the peer group from a variety of sources, including proxy statements and other publicly filed documents and also compiled published survey compensation data from multiple sources, including the Economic Research Institute, Mercer and Towers Watson. This compensation data was then used to compare the compensation of our named executive officers to our peer group where the peer group had individuals serving in similar positions and to the market.

Peer Group:

Brigham Exploration Company

Contango Oil & Gas Company

Endeavour International Corporation

Georesources, Inc.

Gulfport Energy Corporation

Oasis Petroleum Inc.

Petroquest Energy, Inc.

Table of Contents

- Ram Energy Resources, Inc.
- Resolute Energy Corporation
- Rex Energy Corporation
- Warren Resources, Inc.

While the Compensation Consultant makes recommendations to our compensation committee on compensation, our compensation committee and board of directors have full discretion to act and implement compensation decisions independent of the Compensation Consultant's recommendations.

Elements of Our Compensation and Why We Pay Each Element

From our inception, our executive compensation program has consisted primarily of base salary, bonus payments, equity-based incentives, severance and change-in-control benefits, certain perquisites and employee benefits provided to certain of our executive officers. Our compensation committee, assisted by the Compensation Consultant, has developed and continues to develop compensation programs that provide our named executive officers with an overall compensation package suitable to executives of a similarly situated publicly traded company, subject to approval by our board of directors. Although our compensation committee has not yet determined the precise components of all of these compensation programs, we expect that these programs for our named executive officers will consist of five elements: base salary, annual performance-based cash incentive compensation, equity-based compensation, severance and change-in-control benefits and other employee benefits.

Base Salary: Base salary is the fixed annual compensation we pay to each of our named executive officers for carrying out their specific job responsibilities. Base salaries are a major component of the total annual cash compensation paid to our named executive officers. Base salaries are determined after taking into account many factors, including the following:

- the responsibilities of the officer, the level of experience and expertise required for the position and the strategic impact of the position;
- the need to recognize each officer's unique value and demonstrated individual contribution, as well as future contributions; and
- salaries paid for comparable positions in similarly-situated companies.

For 2010, base salaries were determined by our board of directors and management based on industry information and an individual's rank, tenure, experience, performance and job responsibilities and the performance of our company. For 2010, base salaries for our named executive officers increased by nominal amounts for market and cost of living reasons, except in the case of Steve Black, whose increase was due to his promotion to Chief Operating Officer.

The Compensation Consultant provided our compensation committee with an analysis of the base salaries paid to our executive officers in 2010 in comparison to comparable market salaries. Based on the Compensation Consultant's analysis, our compensation committee concluded that the aggregate base salaries of our executives were at or near the market 25th percentile, which is below the market 50th percentile that our compensation committee has determined to be the level necessary to remain competitive with other companies in our peer group reflecting our status as a private company. Accordingly, our compensation committee recommended and our board of directors approved an increase in the base salaries of certain of our named executive officers in order to set their base salaries closer to the market 50th percentile with appropriate adjustments for level of experience and job responsibility. The

Table of Contents

following table shows the base salaries for each of our named executive officers (i) in effect for 2010, (ii) effective as of June 1, 2011 and (iii) at the market 50th percentile.

Name and Position	2010 Base Salary	2011 Base Salary (effective 6/1/2011)	Salary for Market 50th Percentile
Michael R. Starzer, President and Chief Executive Officer	$ 275,018	$ 326,000	$ 447,437
James R. Casperson, Executive Vice President and Chief Financial Officer(1)	n/a	$ 260,000	$ 259,892
C. Stephen Black, Chief Operating Officer(2)	$ 261,538	$ 262,500	$ 273,092
Gary A. Grove, Executive Vice President Engineering and Planning and Interim Chief Operating Officer	$ 225,014	$ 240,000	$ 230,458
Patrick A. Graham, Executive Vice President Corporate Development	$ 180,003	$ 215,000	$ 237,800

(1) Mr. Casperson was appointed as our Chief Financial Officer effective as of October 31, 2011. His salary shown above is effective as of such date. Prior to joining us as Chief Financial Officer, Mr. Casperson was a member of our board of directors for which he was paid $85,000 in the aggregate for board and committee retainers and meeting fees for 2011.

(2) Mr. Black resigned his position as Chief Operating Officer on May 20, 2011 to spend more time with his family. The 2011 salary shown above represents a full year of Mr. Black's salary as in effect on his departure date.

Annual Cash Incentive Compensation: All of our employees, including our named executive officers, are eligible to receive performance-based cash bonuses. For 2010, our bonuses were discretionary and, for the first quarter of 2010, paid quarterly. After the first quarter of 2010, the company discontinued the quarterly bonus practice. Discretionary bonus amounts for the first quarter of 2010 were based on each employee's (including each of our named executive officer's) rank, contributions and performance. Management has historically utilized the aggregate bonus levels paid out by our peers relative to the EBITDAX levels generated each year by those peers as a comparative tool to recommend aggregate bonus levels to our board of directors for approval. The bonus amount approved by our board of directors and paid to employees was entirely discretionary but typically varied between 0.5% and 5% of EBITDAX generated for that year. In 2010, the aggregate bonus level paid to employees represented approximately 1% of EBITDAX generated by the Company. For 2010, Mr. Wilson and Mr. Grove received the largest bonuses for their efforts in refinancing our debt position and achieving strong reserve bookings in 2009, respectively. The amounts received by our named executive officers in 2010 as discretionary bonuses are shown below under "*Summary Compensation Table.*" In lieu of an annual 2010 bonus, in early 2011, we paid a $500,000 aggregate bonus in connection with our Corporate Restructuring. Bonus amounts for this transaction bonus were determined based on each employee's contribution, as determined by management and our board of directors, to our Corporate Restructuring and as a percentage of their 2010 salary. With respect to the $500,000 transaction bonus in connection with our Corporate Restructuring, Mr. Starzer received $58,000, Mr. Black received $56,000, Mr. Grove received $58,000, Mr. Graham received $38,000 and Mr. Wilson received $20,000.

For fiscal year 2011, subject to approval by our board of directors, the compensation committee has discretionary authority to identify the employees entitled to receive an award for the fiscal year and to determine the amount of such award based on performance criteria established by our compensation committee.

We anticipate that our compensation committee will propose for approval by our board of directors an annual performance-based cash incentive, or bonus plan, to take effect upon or shortly after

Table of Contents

consummation of this offering. We expect that the plan proposed by the compensation committee will provide for variable cash compensation earned when established performance objectives are achieved. Such a plan will likely be designed to reward plan participants, including the named executive officers, who have achieved certain corporate and individual performance objectives. Performance criteria may include operational, financial and other performance measures, such as production, safety, retention and individual job-related targets as determined, in the case of our named executive officers, at the discretion of our compensation committee and our board of directors.

This bonus plan will be included as part of our compensation program because we believe this element of compensation will help us to:

- motivate management to achieve key short-term corporate goals; and
- align executives' interests with stockholders' interests.

Long-term Incentives: In connection with our Corporate Restructuring, we adopted the Management Incentive Plan, which we refer to as the MIP. Under the MIP, 10,000 shares of our Class B Common Stock were reserved for issuance in connection with restricted stock awards to our management and employees. Upon the consummation of our Corporate Restructuring on December 23, 2010, 7,500 restricted shares of our Class B Common Stock were granted to our named executive officers as follows: 2,500 to Mr. Starzer, 2,000 to Mr. Grove and 1,500 to each of Messrs. Black and Graham. Mr. Black subsequently forfeited his 1,500 restricted shares of Class B Common Stock upon his resignation and separation from the company. The size of these share grants was determined as a result of negotiations between management and our principal stockholder at the time of our Corporate Restructuring. In connection with his employment, our Board has approved a grant of 600 shares of Class B Common Stock to Mr. Casperson. In connection with this offering, we have granted the remaining 3,400 shares of Class B Common Stock to our management and employees with each such individual grant based on rank, tenure, performance and contribution to the company. All Class B Common Stock has been granted pursuant to Restricted Stock Agreements and, upon consummation of this offering, is subject to a three-year vesting period whereby the Class B Common Stock granted to each individual vests in one third increments annually commencing on the consummation of this offering, provided that such individual remains employed by the company. We feel that the vesting provisions of the Class B Common Stock under the MIP are sufficient to encourage our senior management to produce long-term stockholder value. Upon consummation of this offering, all 10,000 restricted shares of Class B Common Stock under the MIP will be converted into our Class A Common Stock and reclassified as common stock. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*." The MIP will be terminated in connection with the consummation of this offering.

Our board of directors and stockholders have approved a Long Term Incentive Plan, or "LTIP." This LTIP will replace the MIP for equity incentives to be granted following the consummation of this offering. The purpose of our LTIP is to attract and retain the best available personnel for positions of substantial responsibility, to provide additional incentives to our employees, directors and consultants, and to promote the success of our business. Our LTIP provides for grants of (a) incentive stock options qualified as such under U.S. federal income tax laws, (b) stock options that do not qualify as incentive stock options, (c) stock appreciation rights ("SARs"), (d) restricted stock awards, (e) restricted stock units (f) unrestricted stock awards, (g) dividend equivalent rights, (h) performance awards and (i) annual incentive awards.

Our compensation committee believes long-term incentive-based equity compensation is an important component of our overall compensation program because it:

- rewards the achievement of our long-term goals;
- aligns our executives' interests with the long-term interests of our stockholders;

encourages executive retention; and

conserves our cash resources.

In determining awards made under our LTIP, our board of directors or compensation committee, as applicable, will review the Compensation Consultant's market analysis to determine the appropriate amount of equity to grant to our executive officers based on market data while also taking into consideration our performance, individual performance and retention concerns. Our named executive officers and other employees are entitled to participate in our LTIP subject to certain restrictions. Our compensation philosophy is to use the market 50^{th} percentile as a guideline in terms of setting long term incentive compensation, which will be reflected in the size of the grants to our named executive officers under our LTIP. This philosophy is intended to attract, motivate and retain high caliber executive talent, while aligning executives' interests with those of our stockholders. The average portion of total compensation paid as long-term incentives for the named executive officers of our peer group is approximately 40%.

Our LTIP is not subject to the Employee Retirement Income Security Act of 1974, as amended, or "ERISA." For a limited period of time following this offering, we anticipate that our LTIP will qualify for an exception to the deductibility limitations imposed by Section 162(m) of the Internal Revenue Code of 1986, as amended ("Code"), assuming that certain requirements are met. During that limited period of time, awards under our LTIP will be exempt from the limitations on the deductibility of compensation that exceeds $1,000,000. See " *Accounting and Tax Considerations"* below.

The following is a summary of the material terms of our LTIP. This description is not complete. For more information, we refer you to the full text of the LTIP, which we have filed as an exhibit to the registration statement of which this prospectus forms a part.

Administration. Our LTIP is administered by our board of directors, which has full power and authority to take all actions and to make all determinations required or provided for under the LTIP, including designation of grantees, determination of types of awards, determination of the number of shares of common stock subject an award and establishment of the terms and conditions of awards. Our board of directors may amend, modify or supplement any award, provided that the grantee of such award must consent to any such amendment, modification or supplement that impairs the grantee's rights under the award. Our board of directors may delegate to our compensation committee such powers and authorities related to the administration and implementation of our LTIP as our board of directors shall determine, consistent with our certificate of incorporation and bylaws and applicable law.

Award Eligibility. Awards under our LTIP may be made to (i) any employees, officers, directors or certain consultants of us or our affiliates, as our board of directors may designate; (ii) any director who is not an officer or employee of the company; and (iii) any other individual whose participation in our LTIP is determined by our board of directors to be in our best interests. An eligible person may receive more than one award.

Limitation on Awards. For so long as we are a reporting company and after the reliance period under Section 162(m) of the Code has expired, we may award per calendar year up to (i) 250,000 shares of common stock subject to stock options or SARs and (ii) 250,000 shares of common stock other than pursuant to stock options or SARs. We may award to any single grantee up to $2.5 million per calendar year as an annual incentive award and up to $2.5 million per performance period as a performance award or other cash award.

Stock Subject to Our LTIP. 2,500,000 shares of common stock are available for issuance under our LTIP. The number of shares issued or reserved pursuant to our LTIP is subject to adjustment as a result of certain mergers, consolidations, exchanges, conversions, recapitalizations, reclassifications, stock splits, stock dividends or other changes in our common stock. If any shares covered by an award under our LTIP are not purchased or are forfeited, or if an award otherwise terminates without delivery of any shares, then such shares generally shall, to the extent of any such forfeiture or termination, again be available for making awards under our LTIP.

Stock Options. Each stock option granted under our LTIP becomes exercisable at such times and under such conditions as determined by our board of directors. The exercise price of each stock option must be fixed by our board of directors and must be at least the fair market value on the grant date. The exercise price of an incentive stock option may not be less than 110% of the fair market value of a share of common stock on the grant date, unless the grantee owns more than 10% of the total voting power of the company. The exercise price of an option that is a substitute award may be less than 100% of the fair market value of a share of common stock on the original date of grant provided that the exercise price is determined in accordance with the principles of Section 424 of the Code. The exercise price may not be less than the par value of a share of common stock. The exercise price of stock options may not be lowered (either by amendment or by cancellation and reissuance of the stock option) without the approval of our stockholders. Stock options may be exercised by payment of the purchase price. Unless otherwise stated in the applicable award agreement, holders of stock options shall have none of the rights of a stockholder until such stock options are exercised. To the extent permitted by law, the award agreement relating to the stock options may provide for cashless exercise.

SARs. A SAR shall confer on the grantee a right to receive, upon exercise thereof, the excess of (i) the fair market value of one share of common stock on the date of exercise over (ii) the grant price of such SAR. Our board of directors shall determine the grant price of the SAR (which shall be at least the fair market value of a share of common stock on the grant date), the grant date, the time at which the SAR may be exercised, the conditions under which the SAR would no longer be exercisable and other terms. SARs may be granted in conjunction with all or part of a stock option or another award. A SAR granted in tandem with an outstanding stock option following the grant date of such stock option may have a grant price that is equal to the option exercise price, even if such grant price is less than the fair market value of a share of common stock on the grant date of the SAR. The grant price of a SAR that is a substitute award may be less than 100% of the fair market value of a share of common stock on the original date of grant provided that the grant price is determined in accordance with the principles of Section 424 of the Code. The exercise price of SARs may not be lowered (either by amendment or by cancellation and reissuance of the SAR) without the approval of our stockholders.

Restricted Stock or Stock Units. Awards of restricted stock or stock units may not be sold, transferred, assigned, pledged or otherwise encumbered or disposed during a period of time determined by our board of directors. Our board of directors may, at the time of grant, prescribe other restrictions, including satisfaction of corporate or individual performance objectives. Unless otherwise set forth in the award agreement, (i) holders of restricted stock will have voting rights and be entitled to receive dividends and (ii) holders of stock units will have no rights as stockholders. Awards of restricted stock or stock units may be made for no consideration (other than par value of the shares deemed paid by services already rendered). To the extent required by applicable law, grantees must purchase restricted stock from the company at a purchase price equal to the greater of (x) the aggregate par value of the shares or (y) the purchase price specified in the award agreement, if any (however, our board of directors may deem such purchase price paid by services already rendered).

Unrestricted Stock Awards. Our board of directors may grant or sell shares of common stock free of any restrictions. Such awards may be granted or sold in respect of past services and other valid consideration, or in lieu of, or in addition to, any cash compensation due to a grantee.

Dividend Equivalent Rights. A dividend equivalent right is an award entitling the recipient to receive credits based on cash distributions that would have been paid on the shares of common stock specified in the dividend equivalent right (or other award to which it relates) if such shares had been issued to and held by the recipient. A dividend equivalent right may be granted hereunder to any grantee as a component of another award or as a freestanding award. Dividend equivalents credited to the holder of a dividend equivalent right may be paid currently or may be deemed to be reinvested in additional shares of common stock, which may thereafter accrue additional equivalents. Any such reinvestment shall be at fair market value on the date of reinvestment. Dividend equivalent rights may be settled in cash or stock or a combination thereof.

Performance and Annual Incentive Awards. Rights under any award may be subject to performance conditions specified by our board of directors. To the extent required under Section 162(m) of the Code, any power or authority relating to a performance award or annual incentive award intended to qualify under Section 162(m) of the Code, shall be exercised by our compensation committee and not our board of directors. If and to the extent that our compensation committee determines that a performance award or annual incentive award to be granted to a grantee likely to be a "covered employee" under Section 162(m) of the Code should qualify as "performance-based compensation" for purposes of Section 162(m) of the Code, then the grant, exercise and/or settlement of such performance award or annual incentive award shall be contingent upon achievement of pre-established performance goals and other terms. The performance goals must consist of one or more specified business criteria and be objective and otherwise meet the requirements of Section 162(m) of the Code, including the requirement that the level or levels of performance targeted by our compensation committee result in the achievement of performance goals being "substantially uncertain."

Change in Control. Upon the occurrence of a change in control of our ownership, each outstanding award shall be deemed to have vested, and shall become exercisable (if applicable), to the extent so provided in the applicable award agreement. Our board of directors may elect to accelerate the vesting of, or cancel, or take any other action with respect to any outstanding award.

Amendment. Our board of directors may, at any time and from time to time, amend, suspend, or terminate our LTIP as to any shares of common stock as to which awards have not been made. An amendment may be contingent on approval of our stockholders to the extent stated by our board of directors, required by applicable law or required by NYSE listing requirements. In addition, an amendment will be contingent on approval of our stockholders if the amendment to the LTIP would: (i) materially increase the benefits accruing to participants, (ii) materially increase the aggregate number of shares of common stock that may be issued or (iii) materially modify the requirements as to eligibility for participation. No amendment, suspension, or termination may, without the grantee's consent, impair rights or obligations under any outstanding award due such grantee.

Other Employee Benefits: We expect that the named executive officers will continue to be eligible for the same health, welfare and other employee benefits available to our employees generally, including medical and dental insurance, short and long-term disability insurance and a 401(k) plan that includes company matching of 6% of each individual's cash earnings.

Stock Awards: In the fiscal year 2010, we issued 7,500 shares of our Class B Common Stock in the form of shares of restricted stock to our named executive officers, 1,500 of which were subsequently forfeited by Mr. Black upon his resignation. In connection with his employment, our Board approved a grant of 600 shares of our Class B Common Stock to Mr. Casperson. The share amounts were determined in connection with this Corporate Restructuring. In connection with this offering, all of the outstanding Class B Common Stock will automatically be converted into shares of our Class A Common Stock pursuant to a formula set forth in our amended and restated certificate of incorporation and be reclassified as common stock pursuant to our second amended and restated certificate of incorporation. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*." We will issue 437,787 shares of our common stock upon conversion of the Class B Common Stock and reclassification of our Class A Common Stock.

Table of Contents

Salary and Cash Incentive Awards in Proportion to Total Compensation: The following table sets forth the percentage of each named executive officer's total compensation that we paid in the form of base salary and annual cash incentive awards.

Name	Year	Percentage of Total Compensation Paid in Base Salary and Annual Incentive Awards
Michael R. Starzer	2010	95%
	2009	96%
	2008	97%
C. Stephen Black(1)	2010	94%
	2009	90%
	2008	71%
Steven B. Wilson(2)	2010	94%
	2009	91%
	2008	
Gary A. Grove	2010	93%
	2009	90%
	2008	92%
Patrick A. Graham	2010	93%
	2009	89%
	2008	91%

(1) Mr. Black joined us in March 2008 and resigned effective as of May 20, 2011.

(2) Mr. Wilson joined us in June 2009 and resigned effective as of September 2, 2011.

Employment Agreement and Severance and Change in Control Arrangements

In 2009, we entered into employment agreements with each of our named executive officers that provide for base salary, participation in our benefit plans, paid vacation and reimbursement of reasonable business expenses. Such agreements provided for 12 months base salary in a lump sum as severance in the event of a termination of such officer's employment by us without cause, by such officer for good reason, due to permanent disability of such officer or upon resignation of such officer in connection with a change of control of our company.

In connection with our Corporate Restructuring, we amended and restated the employment agreements with Messrs. Starzer, Grove and Graham to provide for participation in the MIP. Mr. Casperson has entered into a similar employment agreement in connection with his employment with our company. Upon termination of employment by us without cause, by the named executive officer for good reason, due to permanent disability of the named executive officer or upon resignation in connection with a change in control of our company, such officer is entitled to (i) an immediate cash payment equal to 12 months base salary; (ii) a cash payment made within 70 days of termination, equal to 12 months base salary plus 200% of the two-year average annual bonuses paid to such officer; and (iii) for 18 months following termination, monthly reimbursement of the difference between such officer's COBRA premiums and the amount our active senior executive employees pay for the same or similar coverage under our group health plan. Such named executive officers are entitled to receive these severance benefits only upon executing a general release. These employment agreements include 2 year post-termination non-competition and non-solicitation clauses.

Table of Contents

Following the consummation of this offering, we plan to amend and restate the existing employment agreements with our named executive officers, including the terms and conditions of employment and the severance and change in control benefits for our named executive officers. We also expect to adopt an executive change in control and severance benefit plan, to be effective after the consummation of this offering, which will provide severance and change in control benefits to participants. We believe that adoption of such an executive change in control and severance benefit plan is appropriate because we believe that the interests of our stockholders are best served if we provide separation benefits to eliminate, or at least reduce, the reluctance of executive officers and other key employees to pursue potential corporate transactions that may be in the best interests of our stockholders, but that may have resulting adverse consequences to the employment situations of our executive officers and other key employees. Further, such a plan will ensure an understanding of what benefits are to be paid to participants in the event of termination of their employment in certain specified circumstances and/or upon the occurrence of a change in control.

Stock Ownership Guidelines

Stock ownership guidelines have not been implemented for our named executive officers or directors. We will continue to periodically review best practices and reevaluate our position with respect to stock ownership guidelines in the future.

Accounting and Tax Considerations

Section 162(m) of the Code

Generally, Section 162(m) of the Code disallows a tax deduction to any publicly-held corporation for individual compensation in excess of $1,000,000 paid in any taxable year to any of its chief executive officer or other named executive officer, other than its chief financial officer, unless the compensation is performance-based. As we are not currently publicly traded, our board of directors and compensation committee have not previously taken the deductibility limit imposed by Section 162(m) of the Code into consideration in setting compensation.

Certain exceptions to the deductibility limitation apply for a limited period of time in the case of companies that become publicly-traded through an initial public offering, assuming certain conditions are satisfied. We expect that our arrangements will fit within that exception; however, we reserve the right to use our judgment to authorize compensation payments that do not comply with the performance-based compensation exemption in Section 162(m) of the Code when we believe that such payments are appropriate and in the best interest of our stockholders, after taking into consideration changing business conditions or the executive's individual performance and/or changes in specific job duties and responsibilities.

Section 409A of the Code

Section 409A of the Code requires that "nonqualified deferred compensation" be deferred and paid under plans or arrangements that satisfy the requirements of the statute with respect to the timing of deferral elections, timing of payments and certain other matters. Failure to satisfy these requirements can expose employees and other service providers to accelerated income tax liabilities and penalty taxes and interest on their vested compensation under such plans. Accordingly, as a general matter, it is our intention to design and administer our compensation and benefits plans and arrangements for all of our employees and other service providers, including our named executive officers, so that they are either exempt from, or satisfy the requirements of, Section 409A of the Code.

Table of Contents

Section 280G of the Code

Section 280G of the Code disallows a tax deduction with respect to excess parachute payments to certain executives of companies which undergo a change in control. In addition, Section 4999 of the Code imposes a 20% excise tax on the individual with respect to the excess parachute payment. Parachute payments are compensation linked to or triggered by a change in control and may include, but are not limited to, bonus payments, severance payments, certain fringe benefits, and payments and acceleration of vesting from long-term incentive plans including stock options and other equity-based compensation. Excess parachute payments are parachute payments that exceed a threshold determined under Section 280G of the Code based on the executive's prior compensation. In approving the compensation arrangements for our named executive officers in the future, our compensation committee will consider all elements of the cost to the company of providing such compensation, including the potential impact of Section 280G of the Code. However, our compensation committee may, in its judgment, authorize compensation arrangements that could give rise to loss of deductibility under Section 280G of the Code and the imposition of excise taxes under Section 4999 of the Code when it believes that such arrangements are appropriate to attract and retain executive talent.

Our employment agreements with our officers, including our named executive officers, do not provide a "gross-up" or other reimbursement payment for any tax liability that such officer might owe as a result of the application of Sections 280G, 4999, or 409A of the Code and we have not agreed and are not otherwise obligated to provide any named executive officers with such a "gross-up" or other reimbursement. The employment agreements with Messrs. Starzer, Grove, Graham and Casperson specify that if any severance payment to such individuals constitutes "parachute payment" (as defined under Section 280G of the Code), then either (i) such payment shall be reduced so that such payment is $1 less than the limitation under Section 280G or (ii) paid in full, whichever produces the better after tax result.

Accounting Standards

Financial Accounting Standards Board (FASB) Accounting Standards Codification, Topic 718, "Compensation Stock Compensation" (ASC Topic 718) requires us to recognize an expense for the fair value of equity-based compensation awards. Grants of stock options, restricted stock and other equity-based awards are accounted for under ASC Topic 718. Our compensation committee regularly considers the accounting implications of significant compensation decisions, especially in connection with decisions that relate to our equity incentive award plans and programs. As accounting standards change, we may revise certain programs to appropriately align accounting expenses of our equity awards with our overall executive compensation philosophy and objectives.

Table of Contents

Summary Compensation Table

The following table shows information concerning the annual compensation for services provided to us by our named executive officers during the fiscal years ended December 31, 2010, 2009 and 2008.

Name and Principal Position	Year	Salary	Bonus(1)	Stock Awards(2)	All Other Compensation(3)	Total
Michael R. Starzer	2010	$ 275,018	$ 4,000	$ 4,000	$ 10,137	$ 293,155
President and	2009	$ 261,342	$ 6,875		$ 11,306	$ 279,523
Chief Executive Officer	2008	$ 275,000	$ 55,700		$ 11,874	$ 342,574
C. Stephen Black(4)	2010	$ 261,538	$ 6,000	$ 2,400	$ 13,619	$ 283,557
Executive Vice President and	2009	$ 205,070	$ 7,031		$ 23,970	$ 236,071
Chief Operating Officer	2008	$ 137,500(5)	$ 26,600		$ 67,176(6)	$ 231,276
Steven B. Wilson(7)	2010	$ 196,543	$ 13,857		$ 12,283	$ 222,683
Vice President and Chief	2009	$ 85,371(8)	$ 4,600		$ 9,146	$ 99,117
Accounting Officer	2008	n/a	n/a		n/a	
Gary A. Grove	2010	$ 225,014	$ 15,192	$ 3,200	$ 14,328	$ 257,734
Executive Vice President	2009	$ 213,825	$ 15,000		$ 24,320	$ 253,145
Engineering and Planning and Interim Chief Operating Officer	2008	$ 211,536	$ 38,500		$ 21,401	$ 271,437
Patrick A. Graham	2010	$ 180,003	$ 9,040	$ 2,400	$ 11,486	$ 202,929
Executive Vice President	2009	$ 174,805	$ 21,950		$ 23,237	$ 219,992
Corporate Development	2008	$ 176,964	$ 43,500		$ 22,911	$ 243,375

(1) Values represent amounts received in 2010 under our discretionary bonus plan. See "*Annual Performance-Based Cash Incentive Compensation*" above.

(2) Amounts reflect the full grant-date fair value of restricted stock awards of our Class B Common Stock granted during 2010 computed in accordance with ASC Topic 718. Beginning with an assumed per share price of $12.52 for the Class A Common Stock, the price paid by the investors in our Corporate Restructuring, the conversion rate of the Class B Common Stock was calculated on a fair market value basis, utilizing the calculation provided in our amended and restated certificate of incorporation and internal financial projections to arrive at an expected Class A Common Stock share price as of the date of the grant which was discounted to present value using a weighted average cost of capital and for lack of control and marketability. A probability factor was added to weight the likelihood that a liquidity event would take place during the forecast period. In addition, following our Corporate Restructuring in connection with the dissolution of Bonanza Creek Energy Company, LLC (BCEC), Class B Units of BCEC held by Messrs. Starzer and Grove were redeemed by BCEC in exchange for 317,142 shares and 135,953 shares, respectively, of Class A Common Stock held by BCEC with an approximate fair value of $4.0 million and $1.7 million, respectively, as of the date of issuance.

(3) Values represent each executives' 401(k) match paid by us and life insurance premiums.

(4) Mr. Black resigned for family reasons effective as of May 20, 2011.

(5) Mr. Black joined us in March 2008; full year 2008 salary would have been $200,000.

(6) Includes $26,007, the purchase price of a truck purchased in March 2008 for Mr. Black's business and personal use.

(7)

Mr. Wilson resigned to pursue other opportunities effective as of September 2, 2011.

(8) Mr. Wilson joined us in June 2009; full year 2009 salary would have been $175,000.

Table of Contents

Grants of Plan-Based Awards

The following table provides information concerning each grant of plan-based awards made to our named executive officers during the fiscal year ended December 31, 2010.

Name	Grant Date	All other stock awards; Number of shares of stock units(1)	Grant date fair value of stock awards(2)
Michael R. Starzer	12/23/10	2,500	$ 4,000
C. Stephen Black(3)	12/23/10	1,500	2,400
Gary A. Grove	12/23/10	2,000	3,200
Patrick A. Graham	12/23/10	1,500	2,400

(1) Consists of restricted shares of Class B Common Stock that, contemporaneously with this offering will be converted into restricted shares of our Class A Common Stock pursuant to a formula set forth in our amended and restated certificate of incorporation and reclassified as common stock pursuant to our second amended and restated certificate of incorporation, of which we estimate that 109,458 shares will be held by Mr. Starzer, 87,566 shares will be held by Mr. Grove and 65,674 shares will be held by Mr. Graham. After the offering, these restricted shares of our common stock will be subject to a three-year vesting period vesting in one-third increments annually commencing on the consummation of this offering. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*."

(2) Amounts reflect the full grant-date fair value of restricted stock awards of our Class B Common Stock granted during 2010 computed in accordance with ASC Topic 718. Beginning with an assumed per share price of $12.52 for the Class A Common Stock, the price paid by the investors in our Corporate Restructuring, the conversion rate of the Class B Common Stock was calculated on a fair market value basis, utilizing the calculation provided in our amended and restated certificate of incorporation and internal financial projections to arrive at an expected Class A Common Stock share price as of the date of the grant which was discounted to present value using a weighted average cost of capital and for lack of control and marketability. A probability factor was added to weight the likelihood that a liquidity event would take place during the forecast period. In addition, following our Corporate Restructuring in connection with the dissolution of BCEC, Class B Units of BCEC held by Messrs. Starzer and Grove were redeemed by BCEC in exchange for 317,142 shares and 135,953 shares, respectively, of Class A Common Stock held by BCEC with an approximate fair value of $4.0 million and $1.7 million, respectively, as of the date of issuance.

(3) Mr. Black resigned effective as of May 20, 2011, at which time his stock award of 1,500 restricted shares of Class B Common Stock was forfeited.

Table of Contents

Outstanding Equity Awards at Fiscal Year End

The following table sets forth certain information with respect to the outstanding stock awards held by the named executive officers at the end of fiscal year 2010.

Name	Grant Date	Number of shares of stock that have not vested(1)	Market Value of shares of stock that have not vested(2)
Michael R. Starzer	12/23/10	2,500	$ 4,000
C. Stephen Black(3)	12/23/10	1,500	2,400
Gary A. Grove	12/23/10	2,000	3,200
Patrick A. Graham	12/23/10	1,500	2,400

(1) Consists of restricted shares of Class B Common Stock that, contemporaneously with this offering, will be converted into restricted shares of our Class A Common Stock pursuant to a formula set forth in our amended and restated certificate of incorporation and reclassified as common stock pursuant to our second amended and restated certificate of incorporation, of which we estimate 109,458 shares will be held by Mr. Starzer, 87,566 shares will be held by Mr. Grove and 65,674 shares will be held by Mr. Graham. After the offering, these restricted shares of will be subject to a three-year vesting period vesting in one-third increments annually commencing on the consummation of this offering. See "*Certain Relationships and Related Party Transactions Class B Common Stock Conversion*."

(2) Amounts reflect the full grant-date fair value of restricted stock awards of our Class B Common Stock granted during 2010 computed in accordance with ASC Topic 718. Beginning with an assumed per share price of $12.52 for the Class A Common Stock, the price paid by the investors in our Corporate Restructuring, the conversion rate of the Class B Common Stock was calculated on a fair market value basis, utilizing the calculation provided in our amended and restated certificate of incorporation and internal financial projections to arrive at an expected Class A Common Stock share price as of the date of the grant which was discounted to present value using a weighted average cost of capital and for lack of control and marketability. A probability factor was added to weight the likelihood that a liquidity event would take place during the forecast period. In addition, following our Corporate Restructuring in connection with the dissolution of BCEC, Class B Units of BCEC held by Messrs. Starzer and Grove were redeemed by BCEC in exchange for 317,142 shares and 135,953 shares, respectively, of Class A Common Stock held by BCEC with an approximate fair value of $4.0 million and $1.7 million, respectively, as of the date of issuance.

(3) Mr. Black resigned effective as of May 20, 2011, at which time his stock award of 1,500 restricted shares of Class B Common Stock was forfeited.

Table of Contents

Potential Payments upon Termination or Change of Control

The table below discloses a hypothetical amount of compensation and/or benefits due to the named executive officers in the event of their termination of employment and/or in the event we undergo a change in control. The amounts disclosed assume such termination and/or such change of control was effective as of December 31, 2010. The amounts below constitute estimates of the amounts that would be paid to the named executive officers upon termination of their employment and/or upon a change in control. The actual amounts to be paid are dependent on various factors, which may or may not exist at the time a named executive officer is actually terminated and/or a change in control actually occurs. Therefore, such amounts and disclosures should be considered "forward looking statements."

		Reason for Termination		
Name	**Payment**	**For Cause, Resignation Without Good Reason or Death**	**Without Cause, Resignation for Good Reason or Expiration of Agreement or Disability**	**Change in Control[(1)]**
Michael R. Starzer	Cash Severance		$ 550,000	$ 550,000
	Bonus Payment		10,875	10,875
	Stock Award[(2)]			
	Health Payment		12,486	12,486
Total			$ 573,361	$ 573,361
C. Stephen Black[(3)]	Cash Severance		$ 525,000	$ 525,000
	Bonus Payment		13,031	13,031
	Stock Award[(2)]			
	Health Payment		17,597	17,597
Total			$ 555,628	$ 555,628
Steven B. Wilson[(4)]	Cash Severance		$ 175,000	$ 175,000
	Bonus Payment			
	Stock Award			
	Health Payment			
Total			$ 175,000	$ 175,000
Gary A. Grove	Cash Severance		$ 450,000	$ 450,000
	Bonus Payment		30,192	30,192
	Stock Award[(2)]			
	Health Payment		15,654	15,654
Total			$ 495,846	$ 495,846
Patrick A. Graham	Cash Severance		$ 360,000	$ 360,000
	Bonus Payment		30,990	30,990
	Stock Award[(2)]			
	Health Payment		15,654	15,654
Total			$ 406,644	$ 406,644

(1) In the case of Messrs. Starzer, Grove and Graham, the severance payment is contingent upon resignation within 30 days following the six-month anniversary of the change in control. In the case of Mr. Wilson, the severance payment was contingent upon resignation within three months following the change in control.

(2)

Upon termination without cause, resignation for good reason, death or permanent disability, one-third of the unvested shares of Class B Common Stock are forfeited with the remaining two-thirds

(i) being retained subject to a three-year cliff vesting schedule as if no termination had occurred or (ii) becoming vested upon a unanimous determination of certain of the remaining members of senior management ("Senior Management"). Upon termination for cause or resignation without good reason, all of the unvested shares of Class B Common Stock are forfeited unless Senior Management unanimously determines to allow two-thirds of such shares (x) to be retained subject to a three-year cliff vesting schedule as if no termination had occurred or (y) to fully vest.

(3) Upon his resignation Mr. Black received property with a fair market value of $12,500 and 36,862 shares of Class A Common Stock as severance in exchange for a full release of the company.

(4) Mr. Wilson resigned effective as of September 2, 2011 to pursue other opportunities. He received severance compensation of $210,000, or 100% of his 2011 salary in effect at the time of his resignation. He also received 9,216 shares of our Class A Common Stock in exchange for a full release of the company.

Pension Benefits

Other than our 401(k) Plan, we do not have any plan that provides for retirement benefits.

Non-Qualified Deferred Compensation

We do not have any plan that provides for the deferral of compensation on a basis that is not tax qualified.

Director Compensation

We did not award any compensation to our non-executive directors during the fiscal year 2010. For 2011, our board of directors believes that attracting and retaining qualified non-executive directors will be critical to the ongoing operation of our company. Accordingly, our board of directors adopted a director compensation plan based on the Compensation Consultant's recommendation and report of the companies in our peer group and utilizing the 50^{th} percentile of our peer group as a guideline.

Our non-executive director compensation plan includes (i) an annual cash retainer of $50,000; (ii) an annual grant of restricted shares of our Class A Common Stock with a grant date fair market value of $80,000, subject to one year cliff vesting; (iii) $2,000 for each board of directors meeting attended and $1,000 for each committee meeting attended; (iv) an additional annual cash retainer for service as the chairman of each of the audit ($15,000), compensation ($10,000), nominating and governance ($5,000), environmental safety and regulatory compliance ($5,000) and reserve ($5,000) committees (provided that, in the event one director serves as the chairman of more than one committee, such director will only receive the highest such retainer); and (v) reimbursement for expenses incurred in connection with service as a director. We expect to make stock grants for 2011 pursuant to this compensation plan under our LTIP shortly following the consummation of this offering. We expect to make stock grants for 2012 and subsequent years in connection with our annual meeting of stockholders.

In 2011, we have paid our non-executive directors for retainers and meeting fees as follows: Mr. Casperson, $85,000; Mr Chronister, $70,000; and Mr. Neveu, $75,000.

Directors who are also members of our executive management will not receive any additional compensation for their service on our board of directors.

Executive Compensation Risk

We have determined that risks arising from our compensation policies and practices are not reasonably likely to have a material adverse effect on us. We do not believe that our current or proposed compensation policies and practices encourage excessive or unnecessary risk-taking.

Table of Contents

Indemnification

Our second amended and restated certificate of incorporation and bylaws will provide indemnification rights to the members of our board of directors and permit us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person's actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. After completion of this offering, we will evaluate our existing director and officer liability insurance coverage and make such adjustments we deem appropriate. Additionally, we have entered into separate indemnity agreements with the members of our board of directors and our executive officers to provide additional indemnification benefits, including the right to receive in advance reimbursements for expenses incurred in connection with a defense for which the director is entitled to indemnification. We believe that the limitation of liability provision in our second amended and restated certificate of incorporation, bylaws and the indemnity agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Table of Contents

SECURITIES AUTHORIZED FOR ISSUANCE UNDER EQUITY COMPENSATION PLANS

The following table represents the securities authorized for issuance under our equity compensation plans as of December 31, 2010.

Equity Compensation Plan Information

Plan category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans[(1)]
Equity compensation plans approved by security holders			2,500
Equity compensation plans not approved by security holders			
Total			2,500

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(1) Represents the 2,500 shares of our Class B Common Stock that were available for issuance under the MIP as of December 31, 2010.

Table of Contents

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Class B Common Stock Conversion

We are authorized to issue up to 10,000 shares of our Class B Common Stock in the form of shares of restricted stock to employees pursuant to our Management Incentive Plan. On December 23, 2010, Class B Common Stock was awarded in the following amounts: 2,500 shares to Michael R. Starzer, a director and President and Chief Executive Officer; 2,000 shares to Gary A. Grove, a director and Executive Vice President Engineering and Planning and Interim Chief Operating Officer; 1,500 shares to Patrick A. Graham, Executive Vice President Corporate Development; and 1,500 shares to C. Stephen Black (which were subsequently forfeited without vesting upon Mr. Black's resignation). Our Board has approved a grant of 600 shares of our Class B Common Stock to Mr. Casperson in connection with his employment. In connection with this offering, we have granted the remaining 3,400 shares of Class B Common Stock to our management and employees. The terms of our Class B Common Stock are identical to the terms of our Class A Common Stock except for the conversion right discussed below. The holders of our Class B Common Stock are entitled to one vote per share, and they vote with the holders of our Class A Common Stock as a single group.

If the Value (as defined below) to be received by us in this offering exceeds the Hurdle Rate of Return (as defined below) with respect to a share of our Original Class A Common Stock (as defined below), all outstanding shares of our Class B Common Stock will be converted automatically into shares of Class A Common Stock immediately prior to this offering based on the following conversion formula:

Each share of Class B Common Stock will be multiplied by

- 0.001% of the product of (1) the number of shares of Original Class A Common Stock and (2) the amount by which the Value of a share of Original Class A Common Stock implied by this offering exceeds the Hurdle Rate of Return as of the closing of this offering; less

- the aggregate of all prior dividends and distributions with respect to a share of Class B Common Stock (currently, no such dividends or distributions have been paid).

The above product will be divided by the per share fair market value of the Class A Common Stock implied by this offering, as determined by our board of directors in good faith.

The following definitions apply to the conversion of the Class B Common Stock:

"Hurdle Rate of Return" equals $12.52 increased at a 10% annual compounded internal rate of return from December 23, 2010, to the date of this offering; provided, however, that if this offering occurs on or prior to June 24, 2012, the Hurdle Rate of Return shall be computed as though this offering occurred on June 24, 2012, which is $14.4442.

"Original Class A Common Stock" means the 29,122,521 shares of our Class A Common Stock outstanding immediately after December 23, 2010, regardless whether such shares have been transferred by the initial owner.

"Value," as it relates to Class A Common Stock, means the sum of the following:

- the per share offering price; plus

- the quotient of

  (x) the amount of all dividends or distributions paid on or prior to this offering with respect to Original Class A Common Stock and all other equity securities (including additional shares of Class A Common Stock) held by a person or entity who acquired Original Class A Common Stock on December 23, 2010, or an affiliate of such person or entity, but excluding equity securities issued at fair market value (as determined in good faith by our board of directors) in connection with bona fide equity financing transactions, divided by

121

Table of Contents

(y) the number of shares of Original Class A Common Stock; plus

the aggregate amount of all dividends and distributions paid with respect of all shares of Class B Common Stock on or prior to this offering, divided by the number of shares of Original Class A Common Stock.

We have paid no dividends or distributions with respect to our Original Class A Common Stock or our Class B Common Stock and do not expect to pay any such dividends or distributions prior to this offering.

The Class B Common Stock conversion rights are subject to adjustment to account for certain changes to our common stock outstanding, including stock splits, stock dividends, stock combinations and recapitalization of our common stock. No fractional shares will be issued upon conversion of any Class B Common Stock, and if fractional shares result from such a conversion, the holder of the Class B Common Stock will be entitled to receive from the company cash equal to the market value of such fractional shares, as determined in good faith by our board of directors.

Our Class B Common Stock was issued as shares of restricted stock subject to a time vesting schedule from the grant date of such Class B Common Stock. Prior to vesting, shares of our Class B Common Stock may be forfeited to us for no consideration and may not be sold, transferred or pledged as collateral. The shares of common stock issued upon conversion of the shares of Class B Common Stock and reclassification of Class A Common Stock immediately prior to this offering will be subject to a three-year vesting schedule commencing upon consummation of this offering.

Based on the calculation above, 10,000 shares of our Class B Common Stock will be converted into 437,787 shares of our Class A Common Stock. Following the conversion of the Class B Common Stock and immediately prior to the completion of this offering, our amended and restated certificate of incorporation will be further amended to provide for only one class of common stock. See "*Description of Capital Stock*."

BCEH

BCEH is managed by Michael R. Starzer, our President and Chief Executive Officer, and Gary A. Grove, our Executive Vice President-Engineering and Planning and Interim Chief Operating Officer, and was formed in connection with our Corporate Restructuring to hold 243,945 shares of our Class A Common Stock for subsequent distribution to our employees pursuant to BCEC's Management Incentive Plan. These shares were issued to BCEH in order to defer any tax liability to the recipient resulting from the issuance until a liquid market in our shares of common stock existed. The shares of our Class A Common Stock issued to Messrs. Black and Wilson were issued from the shares held by BCEH. Our board of directors has approved the grant to certain of our employees prior to this offering of all of the shares of our Class A Common Stock held by BCEH.

BCEC Investment Trust

The BCEC Investment Trust, u/t/a dated April 1, 2011, was formed to hold shares of our common stock received by BCEC in connection with the redemption of BCEC's equity in our Corporate Restructuring and designated for (i) Bonanza Creek Oil Company, LLC; (ii) the co-manager of Bonanza Creek Oil Company, LLC and a former director of BCEC pursuant to his interest in BCEC's Management Incentive Plan; and (iii) employees of BCEC. Mr. Starzer is trustee of this trust. The agreement of both required beneficiaries under the trust, Mr. Starzer and the other co-manager of Bonanza Creek Oil Company, LLC, is required to distribute such shares.

Registration Rights Agreement

We have entered into a registration rights agreement with certain of our stockholders, to whom we refer as "rights holders," including Black Bear and certain clients of AIMCo, relating to the shares of our common stock held by them and covered by the agreement, which shares of common stock we refer to as

Table of Contents

"registrable shares." Under the registration rights agreement, the rights holders have the right, subject to the terms of the lock-up agreements to be executed in connection with this offering between right holders and the underwriters, to require us to register under the Securities Act for offer and sale all or a portion of the registrable shares of such rights holders.

Demand Registration Rights. Black Bear has the right to require us, subject to certain limitations, to register all or a porti