Bonanza Creek Energy, Inc.
Form 10-K
March 22, 2012

Use these links to rapidly review the document
TABLE OF CONTENTS
Item 8. Financial Statements and Supplementary Data.

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the fiscal year ended December 31, 2011

OR

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

Commission file number:

Bonanza Creek Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	**61-1630631** (I.R.S. Employer Identification No.)
410 17th Street, Suite 1500 **Denver, Colorado** (Address of principal executive offices)	**80202** (Zip Code)

(720) 440-6100
(Registrant's telephone number, including area code)

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

(Title of Class)	**(Name of Exchange)**
Common Stock, par value $0.001 per share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: **None**

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

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

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

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

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

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

Large accelerated filer o	Accelerated filer o	Non-accelerated filer ý (Do not check if a smaller reporting company)	Smaller Reporting company o

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

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter: The aggregate market value of the voting common equity held by non-affiliates of the registrant on December 15, 2011, based upon the closing price of $13.61 of the registrant's common stock as reported on the New York Stock Exchange, was approximately $157,705,453. Excludes approximately 27.6 million shares of the registrant's common stock held by current executive officers, directors, and stockholders that the registrant has concluded are affiliates of the registrant. The registrant has elected to use December 15, 2011 as the calculation date, which was the initial trading date of the registrant's common stock on the New York Stock Exchange, because on June 30, 2011 (the last business day of the registrant's second fiscal quarter), the registrant was a privately-held company.

Number of shares of registrant's common stock outstanding as of March 15, 2012: 39,477,584

Table of Contents

BONANZA CREEK ENERGY, INC.
FORM 10-K
FOR THE YEAR ENDED DECEMBER 31, 2011

TABLE OF CONTENTS

Table of Contents

Information Regarding Forward-Looking Statements

This Annual Report on Form 10-K contains various statements, including those that express belief, expectation or intention, as well as those that are not statements of historic fact, that are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities and Exchange Act of 1934, as amended. These forward-looking statements may include projections and estimates concerning our capital expenditures, our liquidity and capital resources, our estimated revenues and losses, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, our business strategy and other statements concerning our operations, economic performance and financial condition. When used in this Annual Report on Form 10-K, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. We have based these forward-looking statements on certain assumptions and analyses we have made in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. The actual results or developments anticipated by these forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control, and may not be realized or, even if substantially realized, may not have the expected consequences.

Forward-looking statements may include statements about:

- 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;

Table of Contents

- 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.

All forward-looking statements speak only as of the date of this Annual Report on Form 10-K. We disclaim any obligation to update or revise these statements unless required by law, and you should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under "Item 1A. Risk Factors" and "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and elsewhere in this Annual Report on Form 10-K. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms defined in this section are used throughout this Annual Report on Form 10-K:

"3-D seismic data" Geophysical data that depicts the subsurface strata in three dimensions.

"Analogous reservoir" Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an "analogous reservoir" refers to a reservoir that shares the following characteristics with the reservoir of interest:

(i) Same geological formation (but not necessarily in pressure communication with the reservoir of interest;

(ii) Same environment of deposition

(iii) Similar geological structure; and

(iv) Same drive mechanism

"Bbl" One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or natural gas liquids.

"Bcf" One billion cubic feet of natural gas.

"Boe" Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

"British thermal unit" The heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

"Basin" A large natural depression on the earth's surface in which sediments generally brought by water accumulate.

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

"Condensate" Liquid hydrocarbons associated with the production of a primarily natural gas reserve.

"Developed reserves" Reserves of any category that can be expected to be recovered through existing wells with existing equipment and operating methods or for which the cost of required equipment is relatively minor when compared to the cost of a new well. Also referred to as "developed oil and gas reserves."

"Development costs" Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

Table of Contents

(ii) Drill and equip development wells, development type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

"Development well" A well drilled within the proved area of a natural gas or oil reservoir to the depth of a stratigraphic horizon known to be productive.

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

"Economically producible" A resource that generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

"Environmental assessment" An environmental assessment, a study that can be required pursuant to federal law to assess the potential direct, indirect and cumulative impacts of a project.

"Exploratory well" A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

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

"Formation" A layer of rock which has distinct characteristics that differ from nearby rock.

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

"MBbl" One thousand barrels of crude oil, condensate or natural gas liquids.

"MBoe" One thousand barrels of oil equivalent.

"Mcf" One thousand cubic feet of natural gas.

"MMBoe" One million barrels of oil equivalent.

"MMBtu" One million British thermal units.

"MMcf" One million cubic feet of natural gas.

"NYMEX" The New York Mercantile Exchange.

"Net acres" The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"Net revenue interest" Economic interest remaining after deducting all royalty interests, overriding royalty interests and other burdens from the working interest ownership.

"Net well" Deemed to exist when the sum of fractional ownership working interests in gross wells equals one. The number of net wells is the sum of the fractional working interest owned in gross wells expressed as whole numbers and fractions of whole numbers.

Table of Contents

"Original oil in place" Refers to the oil in place before the commencement of production. Oil in place is distinct from oil reserves, which are the technically and economically recoverable portion of oil volume in the reservoir.

"Play" A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and gas reserves.

"Plugging and abandonment" Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

"Pooling" Pooling is a provision in an oil and gas lease that allows the operator to combine the leased property with properties owned by others. (Pooling is also known as unitization.) The separate tracts are joined to form a drilling unit. Ownership shares are issued according to the acreage contributed or by the production capabilities of each producing well for fields in later stages of development.

"Productive well" A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

"Proppant" Sized particles mixed with fracturing fluid to hold fractures open after a hydraulic fracturing treatment. In addition to naturally occurring sand grains, man-made or specially engineered proppants, such as resin-coated sand or high-strength ceramic materials like sintered bauxite, may also be used. Proppant materials are carefully sorted for size and sphericity to provide an efficient conduit for production of fluid from the reservoir to the wellbore.

"Proved developed reserves" Proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Also referred to as "proved developed producing reserves."

"Proved reserves" and "proved oil and gas reserves" Under SEC rules for fiscal years ending after December 31, 2009, proved reserves are defined as:

> Those quantities of oil and 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 prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.
>
> The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or gas on the basis of available geoscience and engineering data.
>
> In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, LKH, as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.
>
> Where direct observation from well penetrations has defined a highest known oil, HKO, elevation and the potential exists for an associated gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

Table of Contents

Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Under SEC rules for fiscal years ending prior to December 31, 2009, proved reserves are defined as:

The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any, and (B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir. Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. Estimates of proved reserves do not include the following: (A) Oil that may become available from known reservoirs but is classified separately as indicated additional reserves; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

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

"PUD" Proved undeveloped drilling locations.

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

"Reasonable certainty" A high degree of confidence.

Table of Contents

"Recompletion" The process of re-entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reserves" Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development prospects to known accumulations.

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

"Royalty interest" An interest in an oil and natural gas property entitling the owner to a share of oil or gas production free of production costs.

"Spacing" The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40-acre spacing, and is often established by regulatory agencies. Also referred to as "well spacing."

"Undeveloped acreage" Those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil or gas regardless of whether such acreage contains proved reserves.

"Undeveloped reserves" Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Also referred to as "undeveloped oil and gas reserves."

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

"Wellbore" The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

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

Table of Contents

PART I

Item 1. *Business.*

Overview

Bonanza Creek Energy, Inc. ("BCEI" or, together with our consolidated subsidiaries, the "Company," "we," "us," or "our") 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 Wattenberg Field 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 99.5% and hold an average working interest of approximately 80.7% of our proved reserves, providing us with significant control over the rate of development of our long-lived, low-cost asset base.

As of December 31, 2011, we accumulated 81,174 net leasehold acres across our properties. We are currently focused on exploiting what we have identified as significant resource potential from the Niobrara and Codell formations in the Wattenberg Field located in Colorado, and the oily portion of the Cotton Valley formation in Southern Arkansas. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the development of our project inventory. In 2011, we drilled and completed 106 gross operated wells and 6 non-operated gross wells and had 3 development wells and 3 exploration wells in progress. For those wells drilled and completed, we achieved 100% success in the finding of hydrocarbons, all of which are economic based on current prices as of December 31, 2011. This success has been achieved through the application of the latest drilling, fracturing and completion techniques.

Cawley, Gillespie & Associates, Inc., our independent reserve engineers, estimated our net proved reserves as of December 31, 2011, to be as follows:

Estimated Proved Reserves	Crude Oil (MBbls)	Natural Gas (MMcf)	Natural Gas Liquids (MBbls)	Total Proved (MBoe)
Developed				
Mid-Continent	5,042	14,783	1,237	8,743
Rocky Mountain	5,310	16,530		8,065
California	253			253
Undeveloped				
Mid-Continent	5,926	27,457	2,358	12,860
Rocky Mountain	7,661	34,212		13,363
California	429			429
Total Proved	24,621	92,982	3,595	43,713

Table of Contents

Our average net daily production rate during December 2011 was 6,076 Boe/d, which consisted of 70.4% oil and natural gas liquids.

	Estimated Proved Reserves at December 31, 2011(1)					Estimated Production for the Month Ended December 31, 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 2012 Capital Expenditures (millions)	Net Proved Undeveloped Drilling Locations as of December 31, 2011
Mid-Continent	21,603	49.4%	40.5%	67.4%	$ 410.9	3,609	59.4%	$ 79	116.1
Rocky Mountain	21,428	49.0	37.6	60.5	366.8	2,323	38.2	170	159.4
California	682	1.6	37.1	100.0	16.3	144	2.4	1	11.5
Total	43,713	100.0%	39.0%	64.5%	$ 794.0	6,076	100%	$ 250	287.0

(1) Proved reserves and related future net revenue and PV-10 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 $96.19 per Bbl of crude oil and an average price of $4.12 per MMBtu of natural gas. Adjustments were then made for location, grade, transportation, gravity, and Btu content, as appropriate for the underlying resource, which resulted in a decrease of $6.39 per Bbl of crude oil and an increase of $0.70 per MMBtu of natural gas respectively.

(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 " Reconciliation of PV-10 to Standardized Measure."

Our History

Bonanza Creek Energy, Inc. was incorporated on December 2, 2010 pursuant to the laws of the State of Delaware. On December 23, 2010, in connection with an investment from Project Black Bear LP ("Black Bear"), an entity advised by West Face Capital Inc. ("West Face Capital") and certain clients of Alberta Investment Management Corporation ("AIMCo"), we acquired Bonanza Creek Energy Company, LLC ("BCEC") and Holmes Eastern Company, LLC ("HEC"), which transactions we refer to as our "Corporate Restructuring." We completed the initial public offering of our common stock in December 2011 (our "IPO") pursuant to which 10,000,000 shares of our common stock were sold.

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 Wattenberg Field. Substantially all of these infill locations are characterized by multiple productive horizons.

Table of Contents

Exploit Additional Development Opportunities. We are evaluating additional resource potential opportunities that could result in future development projects on several of our assets. We are evaluating extended length laterals in the Niobrara and horizontal drilling in the Codell formations of the Wattenberg Field. In addition, 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.

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 gas processing facilities and 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.

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 approximately 1,200 drilling locations of which 400 gross (287.0 net) are proved, providing us with multiple years of drilling inventory.

Niobrara Resource Potential. We have accumulated 62,688 net acres in Weld and Jackson Counties, Colorado, targeting the Niobrara and Codell formations. Our acreage is proximate to horizontal drilling operations which have been successfully completed by other operators and we successfully drilled and completed 4 horizontal wells in 2011 which averaged 30 day rates of 469 Boe/d. 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. 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 Wattenberg Field 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. Adequate gathering systems are in place in the Wattenberg Field, 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 80.7% and operate approximately 99.5% 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, in 2011 we expanded our infrastructure by adding an additional gas processing facility in our Dorcheat Macedonia field and plan to further expand this facility in 2012 to accommodate future drilling on our acreage in this region.

Management Team with Proven Operating and Acquisition Skills. Our senior management team has extensive expertise in the oil and gas industry. Our senior technical team has an average of more than 30 years of industry experience, including experience in multiple North American resource

Table of Contents

plays as well as experience in other North American and international basins. We believe our management and technical team is one of our principal competitive strengths relative to our industry peers due to our team's proven track record in identification, acquisition and execution of resource conversion opportunities. In addition, this team possesses substantial expertise in horizontal drilling techniques and fracture stimulation experience.

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. Our liquidity as of December 31, 2011 was approximately $215.5 million, comprised of $213.4 million of availability under our credit facility and approximately $2.1 million of cash on hand.

Our Operations

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

Mid-Continent Region

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, 2011, our estimated proved reserves in this region were 21,602.3 MBoe, 67.4% of which were oil and natural gas liquids and 40.5% of which were proved developed. We currently operate 146 gross (127.5 net) producing wells and, as of December 31, 2011, have an identified drilling inventory of approximately 141 gross (116.1 net) PUD drilling locations on our acreage. During 2011, we drilled 42 gross (37.2 net) wells in the Dorcheat Macedonia and McKamie Patton fields and completed 39 gross (34.4 net) of them by December 31, 2011.

Dorcheat Macedonia. In the Dorcheat Macedonia field, we average an 85.3% working interest and 70.6% net revenue interest, and all of our acreage is held by production. We have approximately 111 gross (94.7 net) producing wells and our average net daily production during December 2011 was approximately 2,289 Boe/d from a proved reserves base of 14,625 MBoe, of which about 60.6% is oil and natural gas liquids. Productive reservoirs range in depth from 4,500 to 9,000 feet in depth. Those reservoirs have included the Smackover, Cotton Valley and the Pettet. Our primary development target is the Cotton Valley.

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. 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, 2011, we have identified approximately 139 gross (114.1 net) PUD drilling locations on our acreage in this area. Currently, we have budgeted for 2012 capital expenditures of $56.0 million for the development of our Dorcheat Macedonia acreage. Under this budget, we expect to drill and complete 38 gross (31.7 net) additional infill PUD locations in the field in 2012 with a complete cost per well of approximately $1.8 million, approximately $1.7 million of which will be for initial drilling and completion. During 2011, we drilled 40 gross (35.2 net) vertical Cotton Valley wells in Dorcheat Macedonia.

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. As of

Table of Contents

December 31, 2011, our estimated proved reserves in these fields were approximately 1,628.8 MBoe, and average net daily production during December 2011 was approximately 199 Boe/d. During 2011, we drilled 2 gross (2.0 net) vertical Cotton Valley wells in McKamie-Patton.

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 three products at the facility's tailgate: propane, 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. 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 $19.0 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 2011. The construction of this new facility is in conjunction with our continued development of the field. In November 2011, we executed an agreement for an additional expansion of this facility. We expect this facility to be online in January 2013 at an aggregate cost of approximately $20 million.

Combined, our Arkansas gas facilities had an average net output of 1,121 Boe/d based on the facility contracts for the month of December 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 Wattenberg Field in Weld County, Colorado and the North Park Basin in Jackson County, Colorado. We hold 83,617 gross (62,688 net) acres in these two areas that currently produce oil, natural gas and CO_2 from the Niobrara, Codell, J-Sand, D-Sand, Pierre B and Dakota formations. As of December 31, 2011, our estimated proved reserves in this region were 21,427.4 MBoe, of which 60.5% were oil and 37.6% were proved developed.

While full-scale vertical drilling of the Niobrara oil shale commenced in the early 1990s, we and other 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. We and 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.

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.

Table of Contents

The Wattenberg Field is believed to occupy the most prospective area of the Niobrara. Within the Wattenberg Field, the Niobrara oil shale is 200 to 300 feet thick and comprises the Smoky Hill Shale and Fort Hayes Limestone. In addition to the Wattenberg Field, 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.

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

Commercial development activities began in the Wattenberg Field 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.

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 Wattenberg Field acreage using horizontal drilling techniques in the Niobrara oil shale.

Our estimated proved reserves in the Wattenberg Field were 20,817 MBoe at December 31, 2011. As of December 31, 2011, we had a total of 193 gross (187.0 net) producing wells and our net average daily production during December 2011 was approximately 2,205 Boe/d. Our working interest for all producing wells averages 96.9% and our net revenue interest is approximately 79.2%.

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 $725,000 and we expect to incur an additional $230,000 per well for refracture stimulation, to be completed in the fifth year after initial completion. As of December 31, 2011, we have identified approximately 219 gross (134.3 net) PUD vertical drilling locations on our acreage in this area.

The Codell sandstone and Niobrara oil shale are blanket deposits in the Wattenberg Field. We continue to expand our proved acreage with our vertical program by drilling non-proved locations. Currently, we estimate our capital expenditures for 2012 will be $64.3 million, which includes drilling 92 gross (84.5 net) vertical wells of which 55 are proved and 37 are non-proved. During 2011, we drilled and completed 66 gross (63.8 net) wells, 14 proved and 52 non-proved.

We intend to employ a mixture of vertical and horizontal drilling techniques with multi-stage fracture completions across our entire acreage position in the Wattenberg Field. Our entire 42,218 gross (29,262 net) acre position in the Wattenberg Field 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.

For the year ended December 31, 2011, we drilled and completed 4 gross (3.9 net) operated horizontal Niobrara wells which had average 30-day rates of 469 Boe/d. On average, these wells cost approximately $4.0 million each. For 2012, we plan to drill and complete 24 gross (19.7 net) wells in the Wattenberg Field at an estimated cost of approximately $82.4 million in the aggregate.

North Park Basin Jackson County, Colorado. We control 41,399 gross (33,426 net) acres in the North Park Basin in northern Jackson County, Colorado. 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.

Table of Contents

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, 2011 were approximately 610.6 MBoe, of which 100% were oil. Our average net production during December 2011 was approximately 119 Boe/d. None of our CO_2 production is currently reflected in our reserve reports. Our development and testing of the North Park Basin began in 2011 with the drilling of 2 gross (2.0 net) vertical wells at a drilling and evaluation cost of approximately $2.6 million for the first well and $4.1 million for the second well as of December 31, 2011.

In 2012, we plan to drill and complete 3 gross (3.0 net) wells in the North Park Basin at a cost of approximately $16.3 million in the aggregate. We also plan to acquire approximately 14,700 acres of 3-D seismic surveys in this area. All of our 41,399 gross (33,426 net) acres in the North Park Basin are prospective for the Niobrara oil shale. 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. As of December 31, 2011, our estimated proved reserves in California were 682 MBoe, of which 100.0% were oil and 37.0% were proved developed. As of December 31, 2011, we had a total of 47 gross (38.1 net) producing wells and our average net daily production was approximately 143 Boe/d. Our working interest for all producing wells averages 81.1% and our net revenue interest is approximately 68.8%. We have identified approximately 14 gross (11.5 net) PUD drilling opportunities in these fields. Currently, we estimate our capital expenditures for 2012 in this area will be $1.0 million.

We believe the opportunity to see additional growth exists on the two thermal properties: Kern River and Midway Sunset. Proved reserves for these two areas are only 453 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. During 2011, the operator at Sargent drilled 3 gross (1.5 net) wells of which 2 gross (1.0 net) were fractured stimulated.

Estimated Proved Reserves

Unless otherwise specifically identified, the summary data with respect to our estimated proved reserves presented below has been prepared by our independent reserve engineering firm in accordance with rules and regulations of the Securities and Exchange Commission (the "SEC") applicable to companies involved in oil and natural gas producing activities. As discussed below, the SEC adopted

Table of Contents

new rules relating to disclosures of estimated reserves that were effective for fiscal years ending on or after December 31, 2009. Our proved reserve estimates do not include probable or possible reserves which may exist, categories which the new SEC rules now permit us to disclose in public reports. Our estimated proved reserves under the SEC rules in effect for the year ended December 31, 2009 were determined using constant prices and unescalated costs based on the prices received and costs incurred on a field-by-field basis as of the year end. For the years ended December 31, 2010 and 2011 and for future periods, our estimated proved reserves were and will be determined using the preceding twelve months' unweighted arithmetic average of the first-day-of-the-month prices, rather than year-end prices. For a definition of proved reserves under the SEC rules for both the fiscal years ending on or after December 31, 2010 and the fiscal year ending December 31, 2009, please see the "Glossary of oil and natural gas terms" included in the beginning of this report.

The table below summarizes our estimated proved reserves and related PV-10 at December 31, 2011 and 2010 for each of our project areas. All of the reserve estimates at December 31, 2011 and 2010 presented in the table below are based on reports prepared by Cawley Gillespie & Associates, Inc., our independent reserve engineers. In preparing its reports, Cawley Gillespie & Associates, Inc. evaluated properties representing all of our PV-10 at December 31, 2011 and 2010 under the new SEC rules. For more information regarding our independent reserve engineers, please see "   Independent Reserve Engineers" below. The information in the following table does not give any effect to or reflect our commodity derivatives.

	At December 31, 2011		At December 31, 2010	
Project Area	**Proved Reserves (MMBoe)**	**PV-10(1)**	**Proved Reserves (MMBoe)**	**PV-10(1)**
		(In millions)		**(In millions)**
Mid-Continent	21.6	$ 410.9	22.9	$ 313.4
Rocky Mountain	21.4	366.8	9.1	135.3
California	0.7	16.3	0.9	12.9
Total	43.7	$ 794.0	32.9	$ 461.6

(1) 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 "   Reconciliation of PV-10 to Standardized Measure."

Table of Contents

The following table sets forth more information regarding our estimated proved reserves at December 31, 2011, 2010 and 2009:

	At December 31,		
	2011	**2010**	**2009(1)**
Reserve Data(2):			
Estimated proved reserves:			
Oil (MMBbls)	28.2	22.4	15.3
Natural gas (Bcf)	93.0	62.9	27.6
Total estimated proved reserves (MMBoe)(3)	43.7	32.9	19.9
Percent oil	65%	68%	77%
Estimated proved developed reserves:			
Oil (MMBbls)	11.8	8.2	4.7
Natural gas (Bcf)	31.3	20.1	7.0
Total estimated proved developed reserves (MMBoe)	17.0	11.6	5.9
Percent oil	69%	71%	80%
Estimated proved undeveloped reserves:			
Oil (MMBbls)	16.4	14.2	10.6
Natural gas (Bcf)	61.7	42.8	20.6
Total estimated proved undeveloped reserves (MMBoe)	26.7	21.3	14.0
PV-10 (in millions)(4)	$ 794.0	$ 461.6	$ 208.2
Standardized Measure (in millions)(5)	$ 666.2	$ 374.7	$ 185.7

(1)

The amounts presented as of December 31, 2009 represent those amounts from BCEC, a predecessor company, and are included for comparative purposes only.

(2)

Proved reserves and related future net revenues, PV-10 and Standardized Measure 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 $96.19 per Bbl of crude oil and an average price of $4.12 per MMBtu of natural gas, $79.43 per Bbl of crude oil and an average price of $4.38 per MMBtu of natural gas and $61.18 per Bbl of crude oil and an average price of $3.87 per MMBtu of natural gas for the years ended December 31, 2009, 2010 and 2011 respectively. Adjustments were made for location and the grade of the underlying resource.

(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. For a reconciliation of our Standardized Measure to PV-10, see " Reconciliation of PV-10 to Standardized Measure."

(5)

Standardized Measure represents the present value of estimated future net cash flows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. In connection with our Corporate Restructuring, we merged into a corporation that is treated as a taxable entity for federal income tax purposes. For further discussion of income taxes, see Note 9 to our audited consolidated financial statements.

Estimated proved reserves at December 31, 2011 were 43.7 MMBoe, a 33% increase from estimated proved reserves of 32.9 MMBoe at December 31, 2010. The increase is primarily due to extensions and discoveries associated with the Rocky Mountain region and is comprised of 168 new proved undeveloped locations and 54 unproved locations that were drilled in year 2011 and moved directly to proved reserves. Another component of the increase was our commodity price assumption for oil which increased $16.76/Bbl to $96.19/Bbl for the year ended December 31, 2011 from $79.43/Bbl for the year ended December 31, 2010.

Estimated proved reserves at December 31, 2010 were 32.9 MMBoe, a 65% increase from reserves of 19.9 MMBoe at December 31, 2009. The increase is primarily due to 9.3 MMBoe acquired from Holmes Eastern Company, LLC in connection with our Corporate Restructuring and accretive drilling and positive reserve revisions from our predecessor Bonanza Creek Energy, Company, LLC. Another component of the increase was our commodity price assumption for oil which increased $18.25/Bbl to $79.43/Bbl for the year ended December 31, 2010 from $61.18/Bbl for the year ended December 31, 2009.

Our PV-10 as of December 31, 2011 was 794.0 million, a 72% increase from PV-10 of $461.6 million at December 31, 2010. The increase in PV-10 during the period was primarily related to commodity price assumption for oil which increased $16.76/Bbl to $96.19/Bbl which increased PV-10 by approximately $123.1 million and positive extensions and discoveries in the Rocky Mountain region which increased PV-10 by approximately $204 million.

Our PV-10 as of December 31, 2010 was $461.6 million, a 122% increase from PV-10 of $208.2 million at December 31, 2009. The increase in PV-10 during the period was related to $115 million of PV-10 value acquired from Holmes Eastern Company, LLC in connection with our Corporate Restructuring, approximately $97.7 million of the increase was related to commodity price assumption for oil which increased $18.25/Bbl to $79.43/Bbl from $61.18/Bbl at December 31, 2009, and approximately $66 million of the increase was related to revisions to previous quantity estimates for our predecessor BCEC. These increases in PV-10 were offset by an $11 million decrease for sales of minerals in place and a decrease of $9 million for the net change in estimated future development cost.

The following table sets forth the estimated future net revenues, excluding derivative contracts, from proved reserves, the present value of those net revenues (PV-10) and the expected benchmark prices used in projecting net revenues at December 31, 2011, 2010 and 2009:

	At December 31,		
	2011	**2010**	**2009**
		(In millions)	
Future net revenues	$ 1,315.0	$ 787.5	$ 365.0
Present value of future net revenues:			
Before income tax (PV-10)	794.0	461.6	208.2
After income tax (Standardized Measure)(1)	666.2	374.7	185.7
Benchmark oil price($/Bbl)(2)	$ 96.19	$ 79.43	$ 61.18

(1) Standardized Measure represents the present value of estimated future net cash inflows from proved oil and natural gas reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses (if applicable), discounted at 10% per annum to reflect timing of future cash flows. For further discussion of income taxes, see Note 9 to our audited consolidated financial statements.

(2) 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. Adjustments were made for location and the grade of the underlying resource.

Future net revenues represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Such calculations at December 31, 2011 and 2010 are based on costs in effect at December 31 of each year

Table of Contents

and the 12-month unweighted arithmetic average of the first-day-of-the-month price for the period January through December of such year, without giving effect to derivative transactions, and are held constant throughout the life of the properties. Such calculations at December 31, 2009 are based on costs and prices in effect at December 31, 2009, without giving effect to derivative transactions, and are held constant throughout the life of the properties. There can be no assurance that the proved reserves will be produced within the periods indicated or that prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Reconciliation of PV-10 to Standardized Measure

PV-10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10%. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the Standardized Measure at December 31, 2011, 2010 and 2009:

	December 31,		
	2011	**2010**	**2009**(1)
	(In millions)		
PV-10	$ 794.0	$ 461.6	$ 208.2
Present value of future income taxes discounted at 10%(2)	(127.8)	(86.9)	(22.5)
Standardized Measure	$ 666.2	$ 374.7	$ 185.7

(1) The amounts presented as of December 31, 2009 represent those amounts for our predecessor BCEC.

(2) Both our predecessor BCEC and HEC were partnerships for federal income tax purposes and, therefore, were not subject to entity-level taxation. Historically, federal or state corporate income taxes have been passed through to the members of each of BCEC and HEC. 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, 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.

Proved Undeveloped Reserves

At December 31, 2011, our proved undeveloped reserves were 26,652 MBoe, an increase of 5,317.4 Mboe over our December 31, 2010 proved undeveloped reserves of 21,334.6 MBoe. The reserve change and number of net wells is summarized in the table below for each of our regions. The largest changes were realized in the Rocky Mountain region resulting primarily from 168 new proved undeveloped locations of which 53 locations were related to our 2011 drilling program and 115 20 acre locations were moved from unproved to proved undeveloped. The growth in the Rocky Mountain region was

Table of Contents

offset by drilling approximately 53 proved undeveloped locations in the Dorcheat field in the Mid-Continent region which resulted in a corresponding increase to proved developed reserves. Our total capital expenditure associated with the conversion of proved undeveloped reserves to proved developed reserves in 2011 was $93.9 million.

Proved Undeveloped Reserves

	2011		**2010**		**Difference**	
Region/Area	**MBoe**	**Net Wells**	**MBoe**	**Net Wells**	**MBoe**	**Net Wells**
Mid Continent	12,859.4	116.1	16,890.2	151.3	(4,030.8)	(35.2)
Rocky Mountain	13,362.5	159.4	3,897.6	77.3	9,464.9	82.1
California	430.1	11.5	546.7	13.6	(116.6)	(2.1)
Total	26,652.0	287.0	21,334.5	242.2	5,317.5	44.8

Technology used to establish proved reserves

Under the new SEC rules, 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, 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. For wells and locations targeting the Niobrara formation, 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 seismic data related to the formation were used to estimate original oil in place.

Table of Contents

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 of Engineering and Planning, Gary A. Grove, is the technical person primarily responsible for overseeing the preparation of our reserves estimates. Mr. Grove has over 29 years of industry experience with positions of increasing responsibility in engineering and evaluations and holds a Bachelor of Science degree in petroleum engineering.

Throughout each fiscal year, the reserve committee of our board of directors and our technical team meet with representatives of our independent reserve engineering firm to review properties and discuss methods and assumptions used in preparation of the proved reserves estimates. The reserve committee meets at least twice each year to discuss and evaluate the valuation and accumulation of data process.

Our technical team also works with our banking syndication members at least twice each year, for a valuation of our reserves by the banks in our lending group and their engineers in determining the borrowing base under our revolving credit facility.

Independent Reserve Engineers

The proved reserves estimate for the Company for the years ended December 31, 2010 and 2011 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 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.

Production, Revenues and Price History

Oil and natural gas are commodities. The price that we receive for the oil and natural gas we produce is largely a function of market supply and demand. Demand for oil and natural gas in the United States has increased dramatically over the last ten years. Natural gas prices have declined over the last three years as a result of a global economic downturn and increased supplies of natural gas.

Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile and we expect that volatility to continue in the future. A substantial or extended decline in oil or natural gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil and natural gas reserves that may be economically produced and our ability to access capital markets.

The following table sets forth information regarding oil and natural gas production, revenues and realized prices and production costs for the periods indicated. For additional information on price

Table of Contents

calculations, please see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

	2009	2010	2011
Oil:			
Production (MBbls)	507.4	484.9	953.0
Average sales price (per Bbl), including hedges	$ 67.40	$ 73.73	$ 86.69
Average sales price (per Bbl), excluding hedges	$ 54.40	$ 75.27	$ 90.56
Natural Gas:			
Production (MMcf)	939.0	1,351.5	2,776.4
Average sales price (per Mcf), including hedges	$ 5.05	$ 4.76	$ 5.09
Average sales price (per Mcf), excluding hedges	$ 3.91	$ 4.99	$ 4.84
Natural Gas Liquids:			
Production (MBbls)	69.1	129.8	183.8
Average sales price (per Bbl), including hedges	$ 41.77	$ 56.23	$ 67.23
Average sales price (per Bbl), excluding hedges	$ 41.77	$ 56.23	$ 67.23
Oil Equivalents:			
Production (MBoe)	733.0	840.0	1,599.5
Average daily production (Boe/d)	2,008	2,301	4,382
Average Production Costs (per Boe)[(1)]	$ 18.35	$ 18.19	$ 13.43

(1) Excludes ad valorem and severance taxes.

Principal Customers

Two of our customers, Lion Oil and Plains Marketing comprised 35% and 45%, respectively, of total revenue for the year ended December 31, 2011. Lion Oil and Plains Marketing, comprised 52% and 30%, respectively, of total revenue for the year ended December 31, 2010.

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 December 31, 2011.

	Oil		Natural Gas(1)		Total		Operated	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Mid-Continent	147	127.8			147	127.8	146	