PEDEVCO CORP
Form 10-K
March 25, 2013

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2012

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACTOF 1934

For the transition period from to

Commission file number: 000-53725

PEDEVCO Corp.
(Exact Name of Registrant as Specified in Its Charter)

Texas	22-3755993
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)

4125 Blackhawk Plaza Circle, Suite 201
Danville, California 94506
(Address of Principal Executive Offices)

(855) 733-3826
(Registrant's Telephone Number,
Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:
None

Securities registered pursuant to Section 12(g) of the Act:
Common Stock, $0.001 par value per share

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

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 ¨ No þ

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 þ No ¨

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

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 the 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. þ

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	o	Smaller reporting company	þ

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 29, 2012 based upon the closing price reported on such date was approximately $3,364,034. Shares of voting stock held by each officer and director and by each person who, as of June 29, 2012, may be deemed to have beneficially owned more than 10% of the outstanding voting stock have been excluded. This determination of affiliate status is not necessarily a conclusive determination of affiliate status for any other purpose.

APPLICABLE ONLY TO ISSUERS INVOLVED IN BANKRUPTCY PROCEEDINGS DURING THE PRECEDING FIVE YEARS:

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. Yes ¨ No ¨

As of March 22, 2013, 42,102,852 shares of the registrant's common stock, $.001 par value per share, were outstanding

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Forward Looking Statements

ALL STATEMENTS IN THIS DISCUSSION THAT ARE NOT HISTORICAL ARE FORWARD-LOOKING STATEMENTS. STATEMENTS PRECEDED BY, FOLLOWED BY OR THAT OTHERWISE INCLUDE THE WORDS "BELIEVES," "EXPECTS," "ANTICIPATES," "INTENDS," "PROJECTS," "ESTIMATES," "PLANS," "MAY INCREASE," "MAY FLUCTUATE" AND SIMILAR EXPRESSIONS OR FUTURE OR CONDITIONAL VERBS SUCH AS "SHOULD", "WOULD", "MAY" AND "COULD" ARE GENERALLY FORWARD-LOOKING IN NATURE AND NOT HISTORICAL FACTS. THESE FORWARD-LOOKING STATEMENTS WERE BASED ON VARIOUS FACTORS AND WERE DERIVED UTILIZING NUMEROUS IMPORTANT ASSUMPTIONS AND OTHER IMPORTANT FACTORS THAT COULD CAUSE ACTUAL RESULTS TO DIFFER MATERIALLY FROM THOSE IN THE FORWARD-LOOKING STATEMENTS. FORWARD-LOOKING STATEMENTS INCLUDE THE INFORMATION CONCERNING OUR FUTURE FINANCIAL PERFORMANCE, BUSINESS STRATEGY, PROJECTED PLANS AND OBJECTIVES. THESE FACTORS INCLUDE, AMONG OTHERS, THE FACTORS SET FORTH BELOW UNDER THE HEADING "RISK FACTORS." ALTHOUGH WE BELIEVE THAT THE EXPECTATIONS REFLECTED IN THE FORWARD-LOOKING STATEMENTS ARE REASONABLE, WE CANNOT GUARANTEE FUTURE RESULTS, LEVELS OF ACTIVITY, PERFORMANCE OR ACHIEVEMENTS. MOST OF THESE FACTORS ARE DIFFICULT TO PREDICT ACCURATELY AND ARE GENERALLY BEYOND OUR CONTROL. WE ARE UNDER NO OBLIGATION TO PUBLICLY UPDATE ANY OF THE FORWARD-LOOKING STATEMENTS TO REFLECT EVENTS OR CIRCUMSTANCES AFTER THE DATE HEREOF OR TO REFLECT THE OCCURRENCE OF UNANTICIPATED EVENTS. READERS ARE CAUTIONED NOT TO PLACE UNDUE RELIANCE ON THESE FORWARD-LOOKING STATEMENTS. REFERENCES IN THIS FORM 10-K, UNLESS ANOTHER DATE IS STATED, ARE TO DECEMBER 31, 2012. AS USED HEREIN, THE “COMPANY,” “WE,” “US,” “OUR” AND WORDS OF SIMILAR MEANING REFER TO PEDEVCO CORP. (D/B/A PACIFIC ENERGY DEVELOPMENT), WHICH WAS KNOWN AS BLAST ENERGY SERVICES, INC. UNTIL JULY 30, 2012, AND ITS WHOLLY-OWNED AND PARTIALLY-OWNED SUBSIDIARIES, EAGLE DOMESTIC DRILLING OPERATIONS LLC, BLAST AFJ, INC. PACIFIC ENERGY DEVELOPMENT CORP., CONDOR ENERGY TECHNOLOGY LLC, WHITE HAWK PETROLEUM, LLC, PACIFIC ENERGY TECHNOLOGY SERVICES, LLC, PACIFIC ENERGY & RARE EARTH LIMITED, BLACKHAWK ENERGY LIMITED AND PACIFIC ENERGY DEVELOPMENT MSL LLC, UNLESS OTHERWISE STATED.

This Annual Report on Form 10-K (this “Annual Report”) may contain forward-looking statements which are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this Annual Report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs and cash flows, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report, the words “could,” “believe,” “anticipate,” “intend,” “estimat “expect,” “may,” “should,” “continue,” “predict,” “potential,” “project” and similar expressions are intended to id forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of oil field labor;

the amount, nature and timing of capital expenditures, including future exploration and development costs;
availability and terms of capital;
drilling of wells;
government regulation and taxation of the oil and natural gas industry;
marketing of oil and natural gas;
exploitation projects or property acquisitions;
costs of exploiting and developing our properties and conducting other operations;
general economic conditions;
competition in the oil and natural gas industry;
effectiveness of our risk management and hedging activities;
environmental liabilities;
counterparty credit risk;

developments in oil-producing and natural gas-producing countries;
future operating results;
estimated future reserves and the present value of such reserves; and
plans, objectives, expectations and intentions contained in this Annual Report that are not historical.

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All forward-looking statements speak only at the date of the filing of this Annual Report. The reader 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 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 “Risk Factors” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and elsewhere in this Annual Report. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf. We do not undertake any obligation to update or revise publicly any forward-looking statements except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

Available Information

We are subject to the information and reporting requirements of the Securities Exchange Act of 1934, or the Exchange Act, under which we file periodic reports, proxy and information statements and other information with the United States Securities and Exchange Commission, or SEC. Copies of the reports, proxy statements and other information may be examined without charge at the Public Reference Room of the SEC, 100 F Street, N.E., Room 1580, Washington, D.C. 20549, or on the Internet at http://www.sec.gov. Copies of all or a portion of such materials can be obtained from the Public Reference Room of the SEC upon payment of prescribed fees. Please call the SEC at 1-800-SEC-0330 for further information about the Public Reference Room.

Financial and other information about PEDEVCO Corp. is available on our website (www.pedevco.com). Information on our website is not incorporated by reference into this report. We make available on our website, free of charge, copies of our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

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PART I

ITEM 1. BUSINESS.

History

We were originally incorporated in September 2000 as Rocker & Spike Entertainment, Inc. In January 2001 we changed our name to Reconstruction Data Group, Inc., and in April 2003 we changed our name to Verdisys, Inc. and were engaged in the business of providing satellite services to agribusiness. In June 2005, we changed our name to Blast Energy Services, Inc. ("Blast") to reflect our new focus on the energy services business.

In January 2007, Blast filed voluntary petitions with the U.S. Bankruptcy Court for the Southern District of Texas – Houston Division (the "Court") under Chapter 11 of Title 11 of the U.S. Bankruptcy Code to dispose of burdensome and uneconomical assets and reorganize our financial obligations and capital structure. In February 2008, the Bankruptcy Court entered an order confirming our Second Amended Plan of Reorganization (the "Plan"). The overall impact of the confirmed Plan was for Blast to emerge with unsecured creditors fully paid, have no then existing debt service scheduled for at least two years, and keep equity shareholders' interests intact.

During 2010, Blast's management chose to change the direction of the Company to attempting to generate operating capital from investing in oil producing properties. As a part of this shift in strategy, in September 2010, with an effective date of October 1, 2010, we closed on the acquisition of oil and gas interests in the North Sugar Valley Field located in Matagorda County, Texas, and we decided to divest our satellite services business unit, which we sold in December 2010.

On July 27, 2012, we acquired through a reverse acquisition, Pacific Energy Development Corp., a privately held Nevada corporation, which we refer to as Pacific Energy Development. As described below, pursuant to the acquisition, the shareholders of Pacific Energy Development gained control of approximately 95% of the voting securities of our company. Since the transaction resulted in a change of control, Pacific Energy Development is the acquirer for accounting purposes. In connection with the merger, which we refer to as the Pacific Energy Development merger, Pacific Energy Development became our wholly owned subsidiary and we changed our name from Blast Energy Services, Inc. to PEDEVCO Corp. Following the merger, we refocused our business plan on the acquisition, exploration, development and production of oil and natural gas resources in the United States, with a primary focus on oil and natural gas shale plays and a secondary focus on conventional oil and natural gas plays.

Business Operations

Overview

We are an energy company engaged in the acquisition, exploration, development and production of oil and natural gas resources in the United States (U.S.), with a primary focus on oil and natural gas shale plays and a secondary focus on conventional oil and natural gas plays. Our current operations are located primarily in the Niobrara Shale play in the Denver-Julesburg Basin in Morgan and Weld Counties, Colorado and the Eagle Ford Shale play in McMullen County, Texas. We also hold an interest in the North Sugar Valley Field in Matagorda County, Texas, though we consider this a non-core asset.

We have approximately 10,224 gross and 2,774 net acres of oil and gas properties in our Niobrara core area. Condor Energy Technology LLC ("Condor"), in which we own a 20% interest and manage with an affiliate of MIE Holdings, Inc., operates our Niobrara interests including three wells in the Niobrara asset with current daily production of approximately 494 BOE (150 BOE net). We believe our current Niobrara assets could contain a gross total of 197

drilling locations.

Our current Eagle Ford position is a 3.97% non-operated working interest in 1,331 acres net to us. This interest is held in White Hawk Petroleum, LLC ("White Hawk"), in which we own a 50% interest and manage with an affiliate of MIE Holdings, Inc. White Hawk owns a 7.939% non-operated working interest in 1,331 acres, of which 50% (3.97% of the non-operated working interest) is net to us.

We also have agreements in place (subject to customary closing conditions) for future operations in the Mississippian Lime play in Comanche, Harper, Barber and Kiowa Counties, Kansas and Woods County, Oklahoma. See "Recent Developments - Mississippian Opportunity (Pending Acquisition)." If the proposed acquisition of the Mississippian asset is completed, upon closing, we will have a 100% operated working interest in 7,006 gross (6,763 net) acres, and will hold an option to acquire an additional 7,880 gross (7,043 net) acres through May 30, 2013. We believe the Mississippian asset could contain a gross total of 84 drilling locations.

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Business Strategy

Our goal is to increase shareholder value by building reserves, production and cash flows at an attractive return on invested capital. We intend to first focus on growing and developing reserves, production and cash flow in our U.S. core assets and then, if opportunity allows, use our relationships and partnership with MIE Holdings to expand into the Pacific Rim with a focus on the underdeveloped China shale gas and other conventional and non-conventional opportunities. We intend to achieve our objectives as follows:

Aggressively drill and develop our existing acreage positions. We plan to aggressively drill our core assets, drilling 11 gross wells on the Niobrara asset and two gross wells on the Eagle Ford asset through the end of 2013 subject to raising the required capital. We believe our drilling programs will allow us to begin converting our undeveloped acreage to developed acreage with production, cash flow and proved reserves.

Acquire additional oil and natural gas opportunities. We plan to leverage our relationships and experienced acquisition team to pursue additional leasehold assets in our core areas as well as continue to pursue additional oil and natural gas interests. We have signed a binding agreement (subject to customary closing conditions) for the acquisition of 100% operated working interests in the Mississippian Lime covering approximately 7,006 gross (6,763 net) acres located in Comanche, Harper, Barber and Kiowa Counties, Kansas, and we expect to complete the acquisition during March 2013, subject to our ability to secure sufficient financing. We also have an option to acquire an additional 7,880 gross (7,043 net) acres in the Mississippian Lime in these counties, as well as Woods County, Oklahoma. We estimate there could be up to 84 potential gross drilling locations on the Mississippian asset, and, if we consummate the acquisition, we anticipate drilling four net wells through the end of 2013. We are also exploring additional oil and natural gas opportunities in our core areas, other areas of the U.S. and Pacific Rim countries, with a particular focus on China.

Leverage expertise of management and external resources. We plan to focus on profitable investments that provide a platform for our management expertise, as described under “Competitive Strengths”. We have also engaged STXRA (as described below under “STXRA”) and other industry veterans as key advisors, and as discussed below, recently formed Pacific Energy Technology Services, LLC with STXRA, for the purpose of providing acquisition, engineering and oil drilling and completion technology services to third parties in the U.S. and Pacific Rim countries. As necessary, we intend to enlist external resources and talent to operate and manage our properties during peak operations.

Engage and leverage strategic alliances in the Pacific Rim. We have already entered into strategic alliances with MIE Holdings, and we intend to partner with additional Chinese energy companies, to (a) acquire producing oil field assets that could provide cash flow to help fund our U.S. development programs, (b) provide technical horizontal drilling expertise for a fee, thus acquiring valuable experience and data in regards to the China shale formations and successful engineering techniques, and (c) acquire interests in domestic China shale-gas blocks and commence exploration of the same.

Limit exposure and increase diversification through engaging in joint ventures. We own various oil and natural gas interests through joint ventures with MIE Holdings, and may in the future enter into similar joint ventures with respect to other oil and gas interests either with MIE Holdings or other partners. We believe that conducting many of our activities through partially owned joint ventures will enable us to lower our risk exposure while increasing our ability to invest in multiple ventures.

Leverage partnerships for financial strength and flexibility. Our joint venture partner, MIE Holdings, has been a strong financial partner. They have advanced us $4.17 million through a short-term note to fund operations and development of the Niobrara asset and $432,433 toward a performance deposit paid to the sellers in connection with the originally contemplated Mississippian transaction. We expect that proceeds from equity and debt offerings and internally generated cash flow will provide us with the financial resources to pay off these amounts due MIE Holdings and

pursue our leasing and drilling and development programs through 2013. We have also met with financial institutions, introduced to us by MIE Holdings, seeking to secure a line of credit that could be used for both acquisition and development costs where needed. We cannot assure you, however, that we will be able to secure any such financing on terms acceptable to us, on a timely basis or at all.

Competition

The oil and natural gas industry is highly competitive. We compete and will continue to compete with major and independent oil and natural gas companies for exploration opportunities, acreage and property acquisitions. We also compete for drilling rig contracts and other equipment and labor required to drill, operate and develop our properties. Most of our competitors have substantially greater financial resources, staffs, facilities and other resources than we have. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be able to pay more for drilling rigs or exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our competitors may also be able to afford to purchase and operate their own drilling rigs.

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Our ability to drill and explore for oil and natural gas and to acquire properties will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. Many of our competitors have a longer history of operations than we have, and most of them have also demonstrated the ability to operate through industry cycles.

Competitive Strengths

We believe we are well positioned to successfully execute our business strategies and achieve our business objectives because of the following competitive strengths:

Management. We have assembled management teams at our Company and joint venture partnerships with extensive experience in the fields of international business development, petroleum engineering, geology, petroleum field development and production, petroleum operations and finance. Several members of the team developed and ran what we believe were successful energy ventures that were commercialized at Texaco, CAMAC Energy Inc., and Rosetta Resources, while members of our team at Condor have drilled and presently manage over 2,000 oil wells in the Pacific Rim and Kazakhstan. We believe that our management team is highly qualified to identify, acquire and exploit energy resources both in the U.S. and Pacific Rim countries, particularly China.

Our management team is headed by our President and Chief Executive Officer, Frank C. Ingriselli, an international oil and gas industry veteran with over 33 years of experience in the energy industry, including as the President of Texaco International Operations Inc., President and Chief Executive Officer of Timan Pechora Company, President of Texaco Technology Ventures, and President, Chief Executive Officer and founder of CAMAC Energy Inc. Our management team also includes Chief Financial Officer and Executive Vice President Michael L. Peterson, who brings extensive experience in the energy, corporate finance and securities sectors, including as a Vice President of Goldman Sachs & Co., Chairman and Chief Executive Officer of Nevo Energy, Inc. (formerly Solargen Energy, Inc.), and a former director of Aemetis, Inc. (formerly AE Biofuels Inc.). In addition, our Senior Vice President and Managing Director, Jamie Tseng, has over 25 years of financial management and operations experience and was a co-founder of CAMAC Energy Inc., and our Executive Vice President and General Counsel, Clark R. Moore, has nearly 10 years of energy industry experience, and formerly served as acting general counsel of CAMAC Energy Inc.

Key Advisors. Our key advisors include STXRA and other industry veterans. According to STXRA, the STXRA team has experience in drilling and completing horizontal wells, including over 100 horizontal wells with lengths exceeding 4,000 feet from 2010 to 2012, as well as experience in both slick water and hybrid multi-stage hydraulic fracturing technologies and in the operation of shale wells and fields. We believe that our relationship with STXRA, both directly and through our jointly-owned services company, Pacific Energy Technology Services, LLC, will supplement the core competencies of our management team and provide us with petroleum and reservoir engineering, petrophysical, and operational competencies that will help us to evaluate, acquire, develop, and operate petroleum resources into the future.

Significant acreage positions and drilling potential. Without giving effect to the Mississippian acquisition opportunity, we have accumulated interests in a total of 11,555 gross (2,827 net) acres in our existing core operating areas, each of which we believe represents a significant unconventional resource play. The majority of our interests are in or near areas of considerable activity by both major and independent operators, although such activity may not be indicative of our future operations. Based on our current acreage position, and without giving effect to the Mississippian acquisition opportunity, we estimate there could be up to 197 potential gross drilling locations on our acreage, and we anticipate drilling approximately 13 gross (3.06 net) wells through the end of 2013, leaving us a substantial drilling inventory for future years.

Marketing

The prices we receive for our oil and natural gas production fluctuate widely. Factors that cause price fluctuation include the level of demand for oil and natural gas, weather conditions, hurricanes in the Gulf Coast region, natural gas storage levels, domestic and foreign governmental regulations, the actions of OPEC, price and availability of alternative fuels, political conditions in oil and natural gas producing regions, the domestic and foreign supply of oil and natural gas, the price of foreign imports and overall economic conditions. Decreases in these commodity prices adversely affect the carrying value of our proved reserves and our revenues, profitability and cash flows. Short-term disruptions of our oil and natural gas production occur from time to time due to downstream pipeline system failure, capacity issues and scheduled maintenance, as well as maintenance and repairs involving our own well operations. These situations can curtail our production capabilities and ability to maintain a steady source of revenue for our company. In addition, demand for natural gas has historically been seasonal in nature, with peak demand and typically higher prices during the colder winter months. See “Risk Factors.”

Oil. Our crude oil is generally sold under short-term, extendable and cancellable agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for crude oil move up and down in direct correlation with the oil market as it reacts to supply and demand factors. Transportation costs related to moving crude oil are also deducted from the price received for crude oil.

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We have entered into a month-to-month Crude Oil Purchase Contract with a third party buyer, pursuant to which the buyer purchases the crude oil produced from our initial three wells in the Niobrara, the FFT2H, Waves 1H, and Logan 2H wells, periodically at a price per barrel equal to the average monthly "Light Sweet Crude Oil" contract price as reported by NYMEX from the first day of the delivery month through the last day of the delivery month, less $8.25 per barrel for transportation costs.

Natural Gas. Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points at or near producing wells to both unaffiliated independent marketing companies and unaffiliated mid-stream companies. We receive proceeds from prices that are based on various pipeline indices less any associated fees for processing, location or transportation differentials.

We have entered into a Gas Purchase Contract, dated June 1, 2012, with DCP Midstream, LP, which we refer to as DCP, pursuant to which we have agreed to sell, and DCP has agreed to purchase, all gas produced from our wells located in Weld County, Colorado as part of our Niobrara asset, at a purchase price equal to 83% of the net weighted average value for gas attributable to us that is received by DCP at its facilities sold during the month, less a $0.06/gallon local fractionation fee, for a period of ten years, terminating June 1, 2022.

We endeavor to assure that title to our properties is in accordance with standards generally accepted in the oil and natural gas industry. Some of our acreage will be obtained through farmout agreements, term assignments and other contractual arrangements with third parties, the terms of which often will require the drilling of wells or the undertaking of other exploratory or development activities in order to retain our interests in the acreage. Our title to these contractual interests will be contingent upon our satisfactory fulfillment of these obligations. Our properties are also subject to customary royalty interests, liens incident to financing arrangements, operating agreements, taxes and other burdens that we believe will not materially interfere with the use and operation of or affect the value of these properties. We intend to maintain our leasehold interests by making lease rental payments or by producing wells in paying quantities prior to expiration of various time periods to avoid lease termination.

Merger with Pacific Energy Development

On July 27, 2012, in order to carry out our business plan, we acquired through a reverse acquisition, Pacific Energy Development Corp., a privately held Nevada corporation, which we refer to as Pacific Energy Development. As described below, pursuant to the acquisition, the shareholders of Pacific Energy Development gained control of approximately 95% of the voting securities of our company. Since the transaction resulted in a change of control, Pacific Energy Development is the acquirer for accounting purposes. In connection with the merger, which we refer to as the Pacific Energy Development merger, Pacific Energy Development became our wholly owned subsidiary and we changed our name from Blast Energy Services, Inc. to PEDEVCO CORP.

As part of the Pacific Energy Development merger, we issued to the shareholders of Pacific Energy Development (a) 17,917,261 shares of our common stock, (b) 19,616,676 shares of our newly created Series A preferred stock, (c) warrants to purchase an aggregate of 1,120,000 shares of our common stock and 692,584 shares of our Series A preferred stock at various exercise prices, and (d) options to purchase an aggregate of 4,235,000 shares of our common stock at various exercise prices. Pursuant to the Pacific Energy Development merger, all of our shares of preferred stock that were outstanding prior to the Pacific Energy Development merger were converted into shares of common stock on a one-for-one basis and we effected a reverse stock split of our common stock on a 1 for 112 shares basis. All share and per share amounts used in this Annual Report have been restated to reflect this reverse stock split.

At the effective time of the Pacific Energy Development merger, (a) Pacific Energy Development owned the Niobrara and Eagle Ford assets and had begun discussions regarding the Mississippian acquisition opportunity, and (b) our primary business was developing the North Sugar Valley Field asset. As a result of our acquisition of Pacific Energy

Development in the Pacific Energy Development merger, we acquired these assets and opportunities of Pacific Energy Development.

In connection with the Pacific Energy Development merger, the directors and executive officers of Pacific Energy Development became our directors and executive officers. See “Management.”

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The following chart reflects our core subsidiaries and joint ventures as of December 31, 2012:

Oil and Gas Properties

We believe that the Niobrara, Eagle Ford and Mississippian Shale plays represent among the most promising unconventional oil and natural gas plays in the U.S. We plan to continue to seek additional acreage proximate to our currently held core acreage. Our strategy is to be the operator, directly or through our subsidiaries and joint ventures, in the majority of our acreage so we can dictate the pace of development in order to execute our business plan. The majority of our capital expenditure budget for the period from January 2013 to December 2013 will be focused on the acquisition, development and expansion of these formations.

The following table presents summary data for our leasehold acreage in our core areas as of December 31, 2012 and our drilling capital budget with respect to this acreage from January 1, 2013 to December 31, 2013, subject to availability of capital.

							Drilling & Land Acquisition Capital Budget January 1, 2013 - December 31, 2013			
	Total Gross Acreage	Ownership Interest		Net Acres	Acre Spacing	Potential Gross -Drilling Locations(3)	Gross Wells	Net Wells	$/Well(4)	Capital Cost (4)
Current Core Assets:										
Niobrara(1)	10,224	27.13	%	2,774	80	180	11	2.98	$4,500,000	$13,410,000
Eagle Ford (2)	1,331	3.97	%	53	60	17	2	0.08	$9,000,000	$720,000
Current Assets	11,555			2,827		197	13	3.06		$14,130,000

(1) As discussed below, we have a 27.13% net ownership interest in the leased acreage in the Niobrara asset (12.15% of the acreage is held directly by us plus 14.98% of the acreage is held by virtue of our 20% interest in Condor, which in turn holds a 74.88% working interest in the leased acreage in the Niobrara asset).

(2) As discussed below, we have a 3.97% ownership in the leased acreage in the Eagle Ford asset (held by virtue of our 50% interest in White Hawk Petroleum, LLC, which holds a 7.939% working interest in the Eagle Ford asset).

(3) Potential gross drilling locations are calculated using the acre spacings specified for each area in the table and adjusted assuming forced pooling in the Niobrara. Colorado, where the Niobrara asset is located, allows for forced pooling, which may create more potential gross drilling locations than acre spacing alone would otherwise indicate.

(4) Cost per well are gross costs while capital costs presented are net to the Company’s working interests.

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Niobrara Asset

Our interests in the Niobrara asset consist of the following:

- We directly hold a portion of our interest in the Niobrara asset through our wholly-owned subsidiary, Pacific Energy Development Corp. These interests are all located within Weld County, Colorado.
- We indirectly hold a portion of our interest in the Niobrara asset by virtue of our 20% ownership in Condor Energy Technology LLC ("Condor"), which is 80% owned by a subsidiary of our partner, MIE Holdings Corporation. These interests are all located within Weld and Morgan Counties, Colorado. Condor is the operator of all of our Niobrara assets (both directly and indirectly owned).

Eagle Ford Asset

We indirectly hold all of our interests in the Eagle Ford asset by virtue of our 50% ownership in White Hawk Petroleum, LLC ("White Hawk"), which is 50% owned by a subsidiary of our partner, MIE Holdings Corporation. These interests are all located within McMullen County, Texas.

North Sugar Valley Asset

We directly hold all of our interests in the North Sugar Valley asset. These interests are all located within Matagorada County, Texas.

Strategic Alliances

MIE Holdings

Through the relationships developed by our founder and Chief Executive Officer, Frank Ingriselli, we formed a strategic relationship with MIE Holdings Corporation (Hong Kong Stock Exchange code: 1555.HK), one of the largest independent upstream onshore oil companies in China, which we refer to as MIE Holdings, to assist us with our plans to develop unconventional shale properties. According to information provided by MIE Holdings, MIE Holdings has drilled and currently operates over 2,000 oil wells in China and brings extensive drilling and completion experience and expertise, as well as a strong geological team. MIE Holdings has also been a significant investor in our operations, and as discussed below, the majority of our oil and gas interests are held all or in part by the following joint ventures which we jointly own with affiliates of MIE Holdings:

- Condor Energy Technology LLC, which we refer to as Condor, which is a Nevada limited liability company owned 20% by us and 80% by an affiliate of MIE Holdings; and
- White Hawk Petroleum, LLC, which we refer to as White Hawk, which is a Nevada limited liability company owned 50% by us and 50% by an affiliate of MIE Holdings.

Although our initial focus is on oil and natural gas opportunities in the U.S., we plan to use our strategic relationship with MIE Holdings and our experience in operating U.S.-based shale oil and natural gas interests to acquire, explore, develop and produce oil and natural gas resources in Pacific Rim countries, with a particular focus on China.

MIE Holdings has been a valuable partner providing us necessary capital in the early stages of our development. It purchased 4 million shares of our Series A preferred stock and acquired an 80% interest in Condor for total consideration of $3 million, and has loaned us the funds to drill and complete our first three Niobrara wells, and to cover other of our Niobrara-related operating and development expenses. MIE Holdings has also introduced us to its banking relationships in order for us to start the process of seeking to obtain a line of credit for future acquisition and

development costs.

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STXRA

On October 4, 2012, we established a technical services subsidiary, Pacific Energy Technology Services, LLC, which is 70% owned by us and 30% owned by South Texas Reservoir Alliance, LLC, which we refer to as STXRA, through which we plan to provide acquisition, engineering, and oil drilling and completion technology services in joint cooperation with STXRA in the U.S. and Pacific Rim countries, particularly in China. While Pacific Energy Technology Services, LLC currently has no operations, only nominal assets and liabilities and has limited capitalization, we anticipated actively developing this venture in 2013. STXRA is a consulting firm specializing in the delivery of petroleum resource acquisition services and practical engineering solutions to clients engaged in the acquisition, exploration and development of petroleum resources. In April 2011, we entered into an agreement of joint cooperation with STXRA in an effort to identify suitable energy ventures for acquisition by us, with a focus on plays in shale oil and natural gas bearing regions in the U.S. According to information provided by STXRA, the STXRA team has experience in their collective careers of drilling and completing horizontal wells, including over 100 horizontal wells with lengths exceeding 4,000 feet from 2010 to 2012, as well as experience in both slick water and hybrid multi-stage hydraulic fracturing technologies and in the operation of shale wells and fields. We believe that our relationship with STXRA, both directly and through our jointly-owned services company, Pacific Energy Technology Services, LLC, will supplement the core competencies of our management team and provide us with petroleum and reservoir engineering, petrophysical, and operational competencies that will help us to evaluate, acquire, develop and operate petroleum resources in the future.

Our Core Areas

The majority of our capital expenditure budget for the period from January to December 2013 will be focused on the acquisition and development of our core oil and natural gas properties: the Niobrara and Eagle Ford Shale plays and the Mississippian Lime play, if acquired as contemplated through the recently executed definitive purchase agreement. The following paragraphs summarize each of these core areas. For additional information, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Liquidity and Capital Resources” and “Business.”

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Niobrara Asset

As of December 31, 2012, we held 2,774 net acres in oil and natural gas properties covering approximately 10,224 gross acres that are located in Morgan and Weld Counties, Colorado that include the Niobrara formation, which we refer to as the Niobrara asset. We hold 1,243 of our Niobrara leased acreage directly, and hold the remaining 1,531 acres through our ownership in Condor, which holds 8,035 acres in the leased acreage in the Niobrara asset. We and/or Condor own working interests in the Niobrara asset ranging from 0.03% to 100%.

Condor is designated as the operator of the Niobrara asset. The day-to-day operations of Condor are managed by our management, and Condor's Board of Managers is comprised of our President and Chief Executive Officer, Mr. Frank Ingriselli, and two designees of MIE Holdings. In addition, MIE Holdings has loaned us approximately $4.17 million to fund operations and development of the Niobrara asset.

Based on approximately 250 square miles of 3D seismic data covering the Niobrara asset, we estimate that there are up to 180 potential gross drilling locations in the Niobrara asset, with 14 initial gross well locations identified for our 2012-2013 Niobrara development plan, including our initial well completed in July 2012 and our second and third wells completed in February 2013, leaving 11 gross wells to be drilled and completed in our plan for 2013. We believe that the Niobrara asset affords us the opportunity to participate in this emerging play at an early stage, with a position in the Denver-Julesburg Basin adjacent to significant drilling activity.

Condor completed drilling the initial horizontal well on the Niobrara asset, the FFT2H, in April 2012, reaching a total combined vertical and horizontal depth of 11,307 feet. Halliburton performed a 20-stage frack of the well in mid-June 2012, with the well being completed in July 2012 with an initial production rate of 437 BOE per day from the Niobrara formation. Condor completed drilling its second horizontal well on the Niobrara asset, the Waves 1H, in November 2012, drilling to 11,114 feet measured depth (6,200 true vertical foot depth) in eight days. The 4,339 foot lateral section was completed in 18 stages by Halliburton in February 2013, and the well tested at an initial production rate of 528 barrels of oil per day and 360 Mcf per day (588 BOE per day) from the Niobrara "B" Bench target zone. Condor also completed drilling its third horizontal well on the Niobrara asset, the Logan 2H, in December 2012 to 12,911 feet measured depth (6,112 true vertical depth) in nine days. The 6,350 foot lateral section was completed in 25 stages by Halliburton in January 2013, and tested at an initial production rate of 522 barrels of oil per day and 360 Mcf per day (585 BOE per day) from the Niobrara "B" Bench target zone.

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Based on publicly available information, we believe that average drilling and completion costs for wells in the Niobrara core area which, for purposes of industry comparisons, we define as Morgan and Weld Counties, Colorado, have ranged between $3.6 million and $6.0 million per well with average estimated ultimate recoveries, or EURs, of 100,000 to 300,000 BOE per well and initial 30-day average production of 300 to 600 BOE per day per well. The costs incurred, EURs and initial production rates achieved by others may not be indicative of the well costs we will incur or the results we will achieve from our wells.

Recently, there has been significant industry activity in the Niobrara Shale play. The most active operators offsetting our acreage position include Carrizo Oil and Gas, Inc. (NASDAQ: CRZO), Continental Resources, Inc. (NYSE: CLR), EOG Resources (NYSE: EOG), Anadarko Petroleum (NYSE: APC), SM Energy (NYSE: SM), Noble Energy (NYSE: NBL), Chesapeake Energy (NYSE: CHK), Whiting Petroleum (NYSE: WLL), Quicksilver Resources (NYSE: KWK), MDU Resources (NYSE: MDU), and Bill Barrett Corp. (NYSE: BBG).

Eagle Ford Asset

As of December 31, 2012, we held 53 net acres in certain oil and gas leases covering approximately 1,331 gross acres in the Leighton Field located in McMullen County, Texas, which is currently producing oil and natural gas from the highly-prospective Eagle Ford Shale formation, which we refer to as the Eagle Ford asset. We hold these interests through our 50% ownership interest in White Hawk, which holds a 7.939% working interest in the Eagle Ford asset.

The Eagle Ford asset currently has three wells that have been drilled and are producing, with gross initial production rates, as publicly disclosed by Texon Petroleum Limited, the operator of the Eagle Ford asset, of 1,202 Bbl per day and 782 Mcf per day for the first well, 1,488 Bbl per day and 700 Mcf per day for the second well, and 1,072 Bbl per day and 1,137 Mcf per day for the third well. During the month of January 2013 the net production attributable to our 3.97% interest from these wells was 330 Bbl of oil and 507 Mcf of natural gas. Based on our current understanding of the field, on the approximately 1,331 gross acre Eagle Ford asset, approximately 17 more Eagle Ford gross wells may be drilled. We expect that the operator will drill two additional gross wells during 2013.

First discovered in 2008, according to data provided by Baker Hughes, the Eagle Ford Shale resource area had an active drilling rig count of 233 horizontal rigs as of December 31, 2012, which accounts for nearly half of the 473 horizontal drilling rigs in the State of Texas as of such date.

Based on publicly available information, we believe that average drilling and completion costs for wells in the Eagle Ford core area which, for purposes of industry comparisons, we define as McMullen County, Texas, have ranged between $8 million and $11 million per well with average estimated ultimate recoveries, or EURs, of 300,000 to 500,000 BOE per well and initial 30-day average production of 800 to 1,500 BOE per day per well. The costs incurred, EURs and initial production rates achieved by others may not be indicative of the well costs we will incur or the results we will achieve from our wells.

Our Non-Core Area

North Sugar Valley Field Asset

We acquired the North Sugar Valley asset in Matagorda County, Texas in connection with our merger with Blast representing an approximately 65% working interest (net revenue interest of approximately 50%) in three wells, the Millberger #1, Millberger #2 and Oxbow #1 wells. Our 2012 year-end reserve report estimates contains approximately 36,988 barrels of proved reserves net to the interest we acquired.

Sun Resources Texas, Inc., a privately-held company based in Longview, Texas, which we refer to as Sun, is the operator of the properties. Sun retains a 1% working interest in the wells.

During late 2011 and early 2012, the down-hole equipment on the Oxbow #1 well began to fail which eventually caused the well to be deemed uneconomic. The Oxbow #1 oil production declined to a point where it was determined it would be more cost effective to have it converted into a salt water disposal well, or SWDs, for the water produced by the Millberger #1 and #2 wells. We have given our consent to pursue such a conversion and Sun is seeking to obtain the approvals and permits for the SWD well. If permits or permissions are not able to be obtained, we will pay our share of the plugging and abandonment costs and will then most likely seek to drill a disposal well at another location on the leases.

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Recent Developments

Mississippian Opportunity (Pending Acquisition)

Pacific Energy Development MSL LLC, our wholly owned Nevada subsidiary which we refer to as PEDCO MSL, has signed a binding agreement (subject to customary closing conditions) with a third party for the acquisition of 100% operated working interests in the Mississippian Lime covering approximately 7,006 gross (6,763 net) acres located in Comanche, Harper, Barber and Kiowa Counties, Kansas, which we refer to as the Mississippian asset, for an aggregate purchase price of $4,207,117. We have also entered into an option agreement with the seller to acquire an additional 7,880 gross (7,043 net) acres in these counties and Woods County, Oklahoma, expiring May 30, 2013. The closing of the acquisition of the Mississippian asset is anticipated to occur in March 2013, subject to satisfaction of certain conditions to closing, and our ability to secure sufficient financing, of which there can be no assurances. Accordingly, we cannot guarantee that we will complete the acquisition in March 2013, or at all.

This pending Mississippian acquisition replaces and supersedes the acquisition previously contemplated by Condor of this Mississippian asset pursuant to an acquisition agreement entered into in November 2012 with the seller, which transaction contemplated the acquisition of the full 13,806 gross acres by Condor for an aggregate purchase price of $8,648,661, with the Company and an affiliate of MIE Holdings each sharing 50% of the purchase price, ownership interest, development and operational expenses with respect to the asset. The new Mississippian transaction now provides for the Company's subsidiary, PEDCO MSL, to acquire the interests in approximately half of the originally contemplated 13,806 total gross acres for approximately half of the originally contemplated cost, with an option to acquire the remaining interests by May 30, 2013, on substantially the same terms and conditions as originally contemplated in Condor's superseded Mississippian acquisition.

We will be the operator of the Mississippian asset, and we anticipate drilling the first well on the Mississippian asset in the second quarter of 2013, with a total of four wells planned in 2013. The Mississippian oil play is one of the latest oil plays that have recently captured attention in the industry, and we believe that there is an opportunity to acquire additional interests in this emerging play on attractive terms.

The following table presents summary data for the leasehold acreage associated with the Mississippian opportunity, not including those acres where we have an option to purchase, and our proposed drilling capital budget with respect to this acreage thru December 31, 2013, assuming we are able to secure sufficient funding and acquire this acreage.

						Drilling & Land Acquisition Capital Budget April 1, 2013 - December 31, 2013			
	Total Gross Acreage	Ownership Interest	Net Acres	Acre Spacing	Potential Gross-Drilling Locations(2)	Gross Wells	Net Wells	$/Well	Capital Cost
Mississippian	7,006	100%	6,763	160	42	4.0	4.0	$ 3,300,000	$ 13,200,000
Acquisition Cost(1)									$ 4,207,117
									$ 17,407,117

(1) Represents our share of the anticipated acquisition costs for the Mississippian asset, assuming we pay 100% of the purchase price, and excluding the exercise of the option to acquire an additional 7,880 gross (7,043 net) acres for an additional $4.2 million.

(2) Potential gross drilling locations are calculated using the acre spacing specified in the table. We have no proved, probable or possible reserves attributable to any of these potential gross drilling locations.

Based on publicly available information, we believe that average drilling and completion costs for wells in the Mississippian core area which, for purposes of industry comparisons, we define as Comanche, Harper, Barber and Kiowa Counties, Kansas and Woods County, Oklahoma, have ranged between $3.2 million and $4.0 million per well with average estimated ultimate recoveries, or EURs, of 250,000 to 500,000 BOE per well and initial 30-day average production of 250 to 1,500 BOE per day per well. The costs incurred, EURs and initial production rates achieved by others may not be indicative of the well costs we will incur or the results we will achieve from our wells.

Possible Reverse Stock Split

On December 3, 2012, our company’s board of directors approved a possible reverse stock split of our common stock and Series A preferred stock in a ratio ranging between 1-for-2 and 1-for-5, with the specific ratio and effective time (if we decide to proceed with the split) to be later determined by the board of directors. Effective December 5, 2012, holders of a majority of our common stock and Series A preferred stock granted the board of directors discretionary authority to determine the specific ratio and effective time for the reverse split. We have filed and mailed to our shareholders an Information Statement on Schedule 14C in connection with such approval. We have not made any adjustments to the amount of shares disclosed in this Annual Report to account for this intended reverse stock split.

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Shale Oil and Natural Gas Overview

The relatively recent surge of oil and natural gas production from underground shale rock formations has had a dramatic impact on the oil and natural gas market in the U.S., where the practice was first developed, and globally. Shale oil production is facilitated by the combination of a set of technologies that had been applied separately to other hydrocarbon reservoir types for many decades. In combination these technologies and techniques have enabled large volumes of oil to be produced from deposits with characteristics that would not otherwise permit oil to flow at rates sufficient to justify its exploitation. The application of horizontal drilling, hydraulic fracturing and advanced reservoir assessment tools to these reservoirs is unlocking a global resource of shale and other unconventional oil and natural gas that the International Energy Agency estimates could eventually double recoverable global oil reserves.

In 2008, U.S. natural gas production was in decline, and the U.S. was on its way to becoming a significant importer of liquefied natural gas (LNG). By 2009, U.S.-marketed natural gas production was 14% higher than in 2005, and in 2010 it surpassed the previous annual production record set in 1973. This turnaround is mainly attributable to shale oil and natural gas output that has more than tripled since 2007. Knowledge is expanding rapidly concerning the shale oil reservoirs that are already being exploited and others that appear suitable for development with current technology. In its preliminary 2011 Annual Energy Outlook, the U.S. Department of Energy (DOE) increased its estimate of recoverable U.S. shale natural gas resources by 238% compared to its previous estimate, bringing U.S. potential natural gas resources to 2,552 trillion cubic feet (TCF), equivalent to more than a century's supply at current consumption rates.

Along with the reduction in economic activity resulting from the recession, the increase in production from shale natural gas has had a significant impact on U.S. average natural gas wellhead prices, which have fallen by more than 30% since 2007. As a result, the value of natural gas has diverged significantly from that of petroleum on an energy-equivalent basis. That has provided substantial economic benefits to natural gas-consuming industries. It has also led to both economic and environmental benefits for the electricity sector, as fired power plants displace power from higher-cost and higher-emitting sources. Shale natural gas has been cited by U.S. Secretary of Energy, Stephen Chu, as helping the world shift to cleaner fuels. A report by the National Petroleum Council (NPC) to Stephen Chu in September 2011 stated that shale oil fields in the U.S. could produce 2 to 3 million barrels of oil per day by 2025, given the right regulatory environment and technology breakthroughs.

Oil and natural gas produced from shale is considered an unconventional resource. Commercial oil and natural gas production from unconventional sources requires special techniques in order to achieve attractive oil and natural gas flow rates. Unlike conventional oil and natural gas, which is typically generated in deeper source rock and subsequently migrates into a sandstone structure with an overlying impermeable layer forming a "trap," shale oil and natural gas is generated from organic material contained within the shale and retained by the rock's inherent low permeability. Permeability is a measure of the ease with which natural gas, oil or other fluids can flow through the material. The same low permeability that secures large volumes of natural gas and liquids in place within the shale strata makes it much more difficult to extract them, even with a large pressure difference between the reservoir and the surface. The location and potential of many of today's productive shale reservoirs were known for many years, but until the development of current shale oil and natural gas techniques these deposits were considered noncommercial or inaccessible.

The main challenge of shale oil and natural gas drilling is to overcome the low permeability of the shale reservoirs. A conventional vertical oil or natural gas well drilled into one of these reservoirs might achieve production, though at reduced rates and for a limited duration before the oil or natural gas volume in proximity to the wellbore is exhausted. That often renders such an approach impractical and uneconomic for exploiting shale oil and natural gas. The two main technologies associated with U.S. shale oil and natural gas production are horizontal drilling and hydraulic fracturing, or "hydrofracking." They are employed to overcome these constraints by greatly increasing the exposure of

each well to the shale stratum and enabling oil and natural gas located farther from the well to flow through the rock and replace the nearby oil and natural gas that has been extracted to the surface.

Instead of drilling a simple vertical well through the shale and then perforating the well within the zone where it is in contact with the shale, the drilling company drills a directional well vertically to within proximity of the shale and then executes a 90-degree turn in order to intersect the shale and then travel for a significant horizontal distance through it. A typical North American shale well has a horizontal extent of 1,000 feet to 5,000 feet or more.

Once the lateral portion of the well has reached the desired extent, the other main technique of shale oil and natural gas drilling is deployed. After the well has been completed, the farthest section of the lateral is perforated, opening up holes through which fluid can flow. This portion of the reservoir is then hydrofracked by injecting fluid into the well under high pressure to fracture the exposed shale rock and open up pathways through which oil and natural gas can flow. The “fracking fluid” consists mainly of water with a variety of chemical additives intended to reduce friction and dissolve minerals, among other purposes, along with sand or sand-like material to prop open the new pathways created by hydrofracking. This process is then repeated at intervals along the well’s horizontal extent, successively perforating and hydrofracking each section in turn. This process creates a producing well that emulates the effect of a vertical well drilled into a conventional oil and natural gas reservoir by substituting multiple horizontal “pay zones” in the shale stratum for the thinner but more prolific vertical pay zone in a more permeable reservoir. Compared to conventional oil and natural gas drilling, the production of oil and natural gas from shale reservoirs thus entails more drilling, on average, and requires a substantial supply of water.

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Shale oil and natural gas are currently being produced from a number of reservoirs in the U.S. Among these are the Bakken Shale in Montana and North Dakota, the Niobrara Shale in northeastern Colorado and parts of adjacent Wyoming, Nebraska, and Kansas, the Eagle Ford Shale in southern Texas, the Mississippian Lime in Kansas and Oklahoma, and the Marcellus Shale spanning several states in the northeastern U.S. According to the 2007 Survey of Energy Resources Report issued by the World Energy Counsel in 2007, the total world resources of shale oil are conservatively estimated at 2.8 trillion barrels, with an estimated nearly 74% of the world's potentially recoverable shale oil resources being concentrated in the U.S., totaling approximately 1.96 trillion barrels of oil.

Regulation

Oil and Natural Gas Regulation

Our oil and natural gas exploration, development, production and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial penalties. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these rules and regulations are frequently amended or reinterpreted and new rules and regulations are promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations. We cannot predict the impact of future government regulation on our properties or operations.

Texas, Colorado, Kansas, Oklahoma and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration, development and production of oil and natural gas. Many states also have statutes or regulations addressing conservation of oil and natural gas matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, the regulation of well spacing, the surface use and restoration of properties upon which wells are drilled, the sourcing and disposal of water used in the drilling and completion process and the plugging and abandonment of these wells. Many states restrict production to the market demand for oil and natural gas. Some states have enacted statutes prescribing ceiling prices for natural gas sold within their boundaries. Additionally, some regulatory agencies have, from time to time, imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below natural production capacity in order to conserve supplies of oil and natural gas. 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.

Some of our oil and natural gas leases are issued by agencies of the federal government, as well as agencies of the states in which we operate. These leases contain various restrictions on access and development and other requirements that may impede our ability to conduct operations on the acreage represented by these leases.

Our sales of natural gas, as well as the revenues we receive from our sales, are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission (FERC) under the Natural Gas Act, as well as under Section 311 of the Natural Gas Policy Act. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. The natural gas industry has historically, however, been heavily regulated and we can give no assurance that the current less stringent regulatory approach of FERC will continue.

In 2005, Congress enacted the Energy Policy Act of 2005. The Energy Policy Act, among other things, amended the Natural Gas Act to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the

market for sale or transportation of physical natural gas in interstate commerce, and to significantly increase the penalties for violations of the Natural Gas Act, the Natural Gas Policy Act of 1978, or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. Should we violate the anti-market manipulation laws and related regulations, in addition to FERC-imposed penalties, we may also be subject to third-party damage claims.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. 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. Because these regulations will apply to all intrastate natural gas shippers within the same state on a comparable basis, we believe that the regulation in any states in which we operate will not affect our operations in any way that is materially different from our competitors that are similarly situated.

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The price we receive from the sale of oil and natural gas liquids will be affected by the availability, terms and cost of transportation of the products to market. Under rules adopted by FERC, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions, which varies from state to state. We are not able to predict with certainty the effects, if any, of these regulations on our operations.

In 2007, the Energy Independence & Security Act of 2007 (the "EISA"), went into effect. The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations and establishes penalties for violations thereunder. We cannot predict any future regulations or their impact.

U.S. Federal and State Taxation

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. In the past, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. President Obama has recently proposed sweeping changes in federal laws on the income taxation of small oil and natural gas exploration and production companies such as us. President Obama has proposed to eliminate allowing small U.S. oil and natural gas companies to deduct intangible U.S. drilling costs as incurred and percentage depletion. Many states have raised state taxes on energy sources, and additional increases may occur. Changes to tax laws could adversely affect our business and our financial results.

Environmental Regulation

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Our activities are subject to a variety of environmental laws and regulations, including but not limited to the Oil Pollution Act of 1990 (OPA 90), the Clean Water Act (CWA), the Comprehensive Environmental Response, Compensation and Liability Act (CERCLA), the Resource Conservation and Recovery Act (RCRA), the Clean Air Act (CAA), the Safe Drinking Water Act (the SDWA) and the Occupational Safety and Health Act (OSHA), as well as comparable state statutes and regulations. We are also subject to regulations governing the handling, transportation, storage and disposal of wastes generated by our activities and naturally occurring radioactive materials (NORM) that may result from our oil and natural gas operations. Civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, limit or prohibit other activities because of protected wetlands, areas or species and require investigation and cleanup of pollution. We intend to remain in compliance in all material respects with currently applicable environmental laws and regulations.

OPA 90 and its regulations impose requirements on "responsible parties" related to the prevention of crude oil spills and liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the U.S. A "responsible party" under OPA 90 may include the owner or operator of an onshore facility. OPA 90 subjects responsible parties to strict joint and several financial liability for removal costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. It also imposes other requirements on responsible parties, such as the preparation of an oil spill contingency plan. Failure to comply with OPA 90 may subject a responsible party to civil or criminal enforcement action. We may conduct operations on acreage located near, or that affects navigable waters subject to OPA 90.

The CWA imposes restrictions and strict controls regarding the discharge of produced waters and other wastes into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits are required to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, produced sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Furthermore, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other pollutants and impose liability for the costs of removal or remediation of contamination resulting from such discharges. In furtherance of the CWA, the EPA promulgated the Spill Prevention, Control, and Countermeasure (SPCC) regulations, which require certain oil-storing facilities to prepare plans and meet construction and operating standards.

CERCLA, also known as the “Superfund” law, and comparable state statutes impose liability, without regard to fault or the legality of the original conduct, on various classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Persons who are responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Our operations may, and in all likelihood will, involve the use or handling of materials that may be classified as hazardous substances under CERCLA. Furthermore, we may acquire or operate properties that unknown to us have been subjected to, or have caused or contributed to, prior releases of hazardous wastes.

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RCRA and comparable state and local statutes govern the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. We generate hazardous and nonhazardous solid waste in connection with our routine operations. At present, RCRA includes a statutory exemption that allows many wastes associated with crude oil and natural gas exploration and production to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses. Hazardous wastes are subject to more stringent and costly disposal requirements than are nonhazardous wastes.

The CAA and comparable state laws restrict the emission of air pollutants from many sources, including oil and natural gas production. These laws and any implementing regulations impose stringent air permit requirements and require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, or to use specific equipment or technologies to control emissions. On July 28, 2011, the EPA proposed new regulations targeting air emissions from the oil and natural gas industry. The proposed rules, if adopted, would impose new requirements on production and processing and transmission and storage facilities.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal or cleanup requirements or operating requirements could materially adversely affect our operations and financial position, as well as those of the oil and natural gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” and including carbon dioxide and methane, may be contributing to the warming of the Earth’s atmosphere. As a result, there have been attempts to pass comprehensive greenhouse gas legislation. To date, such legislation has not been enacted. Any future federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce depressing the prices we receive for oil and natural gas.

On December 15, 2009, the EPA published its finding that emissions of greenhouse gases 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 greenhouse gases under existing provisions of the CAA. Subsequently, the EPA proposed and adopted two sets of regulations, one of which requires a reduction in emissions of greenhouse gases from motor vehicles and the other of which regulated emissions of greenhouse gases from certain large stationary sources. In addition, on October 30, 2009, the EPA published a rule requiring the reporting of greenhouse gas emissions from specified sources in the U.S. beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA released a rule that expands its final rule on greenhouse gas emissions reporting to include owners and operators of onshore and offshore oil and natural gas production, onshore natural gas processing, natural gas storage, natural gas transmission and natural gas distribution facilities. Reporting of greenhouse gas emissions from such onshore production became required on an annual basis beginning in 2012 for emissions occurring in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could, and in all likelihood will, require us to incur costs to reduce emissions of greenhouse gases associated with our operations adversely affecting our profits or could adversely affect demand for the oil and natural gas we produce depressing the prices we receive for oil and natural gas.

Some states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Although most of the state-level initiatives have to date focused on significant sources of greenhouse gas emissions,

such as coal-fired electric plants, it is possible that less significant sources of emissions could become subject to greenhouse gas emission limitations or emissions 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.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. In our industry, underground injection not only allows us to economically dispose of produced water, but if injected into an oil bearing zone, it can increase the oil production from such zone. The SDWA establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. We currently do not own or operate any underground injection wells, but may do so in the future. Failure to obtain, or abide by, the requirements for the issuance of necessary permits could subject us to civil and/or criminal enforcement actions and penalties.

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Oil and natural gas exploration and production, operations and other activities have been conducted at some of our properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, may require remediation. In addition, we occasionally must agree to indemnify sellers of producing properties from whom we acquire reserves against some of the liability for environmental claims associated with these properties. We cannot assure you that the costs we incur for compliance with environmental regulations and remediating previously or currently owned or operated properties will not result in material expenditures that adversely affect our profitability.

Additionally, in the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks, of oil or other materials will occur, and we will incur costs for waste handling and environmental compliance. It is also possible that our oil and natural gas operations may require us to manage NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states, including Texas, have enacted regulations governing the handling, treatment, storage and disposal of NORM. Moreover, we will be able to control directly the operations of only those wells for which we act as the operator. Despite our lack of control over wells owned by us but operated by others, the failure of the operator to comply with the applicable environmental regulations may, in certain circumstances, be attributable to us.

We are subject to the requirements of OSHA and comparable state statutes. The OSHA Hazard Communication Standard, the “community right-to-know” regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require us to organize information about hazardous materials used, released or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in OSHA workplace standards.

We cannot assure you that more stringent laws and regulations protecting the environment will not be adopted or that we will not otherwise incur material expenses in connection with environmental laws and regulations in the future. 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-interpretation 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. 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 some, but not all, potential risks and losses associated with our industry and operations. We do not currently carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition and results of operations.

Hydraulic Fracturing Regulation

We use hydraulic fracturing as a means to maximize the productivity of our oil and natural gas wells in most wells that we drill and complete. Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately 60% of the drilling and completion costs for our horizontal wells are associated with hydraulic fracturing activities. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditures budget.

Hydraulic fracturing technology, which has been used by the oil and natural gas industry for more than 60 years and is constantly being enhanced, enables companies to produce crude oil and natural gas that would otherwise not be recovered. Specifically, hydraulic fracturing is a process in which pressurized fluid is pumped into underground formations to create tiny fractures or spaces that allow crude oil and natural gas to flow from the reservoir into the well so that it can be brought to the surface. The makeup of the fluid used in the hydraulic fracturing process is typically more than 99% water and sand, and less than 1% highly diluted chemical additives. While the majority of the sand remains underground to hold open the fractures, a significant percentage of the water and chemical additives flow back and are then either recycled or safely disposed of at sites that are approved and permitted by the appropriate regulatory authorities. Hydraulic fracturing generally takes place thousands of feet underground, a considerable distance below any drinking water aquifers, and there are impermeable layers of rock between the area fractured and the water aquifers.

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Recently, there has been increasing regulatory scrutiny of hydraulic fracturing, which is generally exempted from regulation as underground injection on the federal level pursuant to the SDWA. However, the U.S. Senate and House of Representatives have considered legislation to repeal this exemption. If enacted, these proposals 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. These legislative proposals have also contained language 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 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 business, financial condition and results of operations.

In addition, at the federal level and in some states, there has been a push to place additional regulatory burdens upon hydraulic fracturing activities. Certain bills have been introduced in the Senate and the House of Representatives that, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could, and in all likelihood would, result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing operations and increasing our costs of compliance. At the state level, Wyoming and Texas, for example, have enacted requirements for the disclosure of the composition of the fluids used in hydraulic fracturing. On June 17, 2011, Texas signed into law a mandate for public disclosure of the chemicals that operators use during hydraulic fracturing in Texas. The law went into effect September 1, 2011. State regulators have until 2013 to complete implementing rules. In addition, several local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address hydraulic fracturing activities. Additional burdens upon hydraulic fracturing, such as reporting requirements or permitting requirements for the hydraulic fracturing activity, will result in additional expense and delay in our operations.

We are not able to predict the timing, scope and effect of any currently proposed or future laws or regulations regarding hydraulic fracturing, but the direct and indirect costs of such laws and regulations (if enacted) could materially and adversely affect our business, financial conditions and results of operations. See “Risk Factors,” including “Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured” and "Federal and state legislation and regulatory initiatives relating to hydraulic fracturing and water disposal could result in creased costs and additional operating restrictions or delays."

International Regulation

Our anticipated future exploration and production operations outside the U.S. will be subject to various types of regulations imposed by the respective governments of the countries in which our operations may be conducted and that may affect our operations and costs. We currently have no operations outside of the U.S. We have not yet assessed the scope and effect of any currently proposed or future foreign laws, regulations or treaties, including those regarding climate change and hydraulic fracturing, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations, financial condition and competitive position.

Insurance

Our oil and gas properties are subject to hazards inherent in the oil and gas industry, such as accidents, blowouts, explosions, implosions, fires and oil spills. These conditions can cause:

- damage to or destruction of property, equipment and the environment; and

personal injury or loss of life; and,
suspension of operations.

We maintain insurance coverage that we believe to be customary in the industry against these types of hazards. However, we may not be able to maintain adequate insurance in the future at rates we consider reasonable. In addition, our insurance is subject to coverage limits and some policies exclude coverage for damages resulting from environmental contamination. The occurrence of a significant event or adverse claim in excess of the insurance coverage that we maintain or that is not covered by insurance could have a material adverse effect on our financial condition and results of operations.

Patents and Licenses

In February 2009, we filed a provisional patent (application number 61/152,885) relating to the process and unique equipment related to our applied fluid jetting process ("AFJ"). In February 2010, the final patent application was submitted. This patent was approved by the U.S. Patent Office in September 2012. We are currently in the process of working with the inventor to assign the rights to the patent to us.

During 2009, we tested the AFJ process on wells in the Austin Chalk play in Central Texas operated by Reliance Oil & Gas, Inc., which we refer to as Reliance, and had some initial production success. We subsequently attempted to apply the process to third-party wells in West Texas and in Kentucky. Due to mechanical failures of the surface equipment, we were unable to achieve any lateral jetting in the down-hole environment. Currently, the AFJ rig and other support vehicles have been moved to a storage yard in Spring, Texas. The AFJ asset is a secondary, non-core business focus for our company and may not ever be commercialized.

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Although we believe the applied fluid technology and related trade secrets may provide us with a competitive edge in the oil and gas service industry, we do not believe this technology to be core to our current business and we are currently not actively pursuing its development and commercialization. However, we are highly committed to protecting the technology. We cannot assure our investors that the scope of any protection we are able to secure for our technology will be adequate to protect such technology, or that we will have the financial resources to engage in litigation against parties who may infringe upon us or seek to rescind their agreements with us. We also cannot provide our investors with any degree of assurance regarding the possible independent development by others of technology similar to that which we have acquired, thereby possibly diminishing our competitive edge.

Employees

At December 31, 2012, we had 10 full-time employees. We believe that our relationships with our employees are satisfactory. No employee is covered by a collective bargaining agreement. In order to expand our operations in accordance with our business plan, we intend to hire additional employees with expertise in the areas of corporate development, petroleum engineering, geological and geophysical sciences and accounting, as well as hiring additional technical, operations and administrative staff. We are not currently able to estimate the number of employees that we will hire during the next twelve months since that number will depend upon the rate at which our operations expand and upon the extent to which we engage third parties to perform required services.

From time to time, we use the services of independent consultants and contractors to perform various professional services, particularly in the areas of geology and geophysics, construction, design, well site surveillance and supervision, permitting and environmental assessment and legal and income tax preparation and accounting services. Independent contractors, at our request, drill our wells and perform field and on-site production operation services for us, including pumping, maintenance, dispatching, inspection and testing.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas terms used in this Annual Report.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report in reference to crude oil or other liquid hydrocarbons.

Bcf. An abbreviation for billion cubic feet. Unit used to measure large quantities of gas, approximately equal to 1 trillion Btu.

BOE. Barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids, to six Mcf of natural gas.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The operations required to establish production of oil or natural gas from a wellbore, usually involving perforations, stimulation and/or installation of permanent equipment in the well 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.

Conventional resources. Natural gas or oil that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the natural gas or oil to readily flow to the wellbore.

Developed acreage. The number of acres that are allocated or assignable to productive wells.

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

Estimated ultimate recovery or EUR. Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

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

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Farmin or farmout. An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farmin” while the interest transferred by the assignor is a “farmout.”

FERC. Federal Energy Regulatory Commission.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which a working interest is owned.

Held by production. An oil and natural gas property under lease in which the lease continues to be in force after the primary term of the lease in accordance with its terms as a result of production from the property.

Horizontal drilling or well. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a horizontal well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Liquids. Liquids, or natural gas liquids, are marketable liquid products including ethane, propane, butane and pentane resulting from the further processing of liquefiable hydrocarbons separated from raw natural gas by a natural gas processing facility.

MBbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mcf. One thousand cubic feet of natural gas.

MMcf. One million cubic feet of natural gas.

MMBtu. One million British thermal units.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells.

Net revenue interest. The interest that defines the percentage of revenue that an owner of a well receives from the sale of oil, natural gas and/or natural gas liquids that are produced from the well.

NYMEX. New York Mercantile Exchange.

Permeability. A reference to the ability of oil and/or natural gas to flow through a reservoir.

Petrophysical analysis. The interpretation of well log measurements, obtained from a string of electronic tools inserted into the borehole, and from core measurements, in which rock samples are retrieved from the subsurface, then combining these measurements with other relevant geological and geophysical information to describe the reservoir rock properties.

Play. A set of known or postulated oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Possible reserves. Additional reserves that are less certain to be recognized than probable reserves.

Probable reserves. Additional reserves that are less certain to be recognized than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

Producing well, production well or productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the well's production exceed production-related expenses and taxes.

Properties. Natural gas and oil wells, production and related equipment and facilities and natural gas, oil or other mineral fee, leasehold and related interests.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

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Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

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.

Repeatability. The potential ability to drill multiple wells within a prospect or trend.

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

Royalty interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

2-D seismic. The method by which a cross-section of the earth's subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.

3-D seismic. The method by which a three-dimensional image of the earth's subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do 2-D seismic surveys and contribute significantly to field appraisal, exploitation and production.

Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

Unconventional resource play. A set of known or postulated oil and or natural gas resources or reserves warranting further exploration which are extracted from (a) low-permeability sandstone and shale formations and (b) coalbed methane. These plays require the application of advanced technology to extract the oil and natural gas resources.

Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage is usually considered to be all acreage that is not allocated or assignable to productive wells.

Unproved and unevaluated properties. Refers to properties where no drilling or other actions have been undertaken that permit such property to be classified as proved.

Vertical well. A hole drilled vertically into the earth from which oil, natural gas or water flows or is pumped.

Volumetric reserve analysis. A technique used to estimate the amount of recoverable oil and natural gas. It involves calculating the volume of reservoir rock and adjusting that volume for the rock porosity, hydrocarbon saturation, formation volume factor and recovery factor.

Wellbore. The hole made by a well.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

ITEM 1A. RISK FACTORS.

An investment in our common stock involves a high degree of risk. You should carefully consider the risks described below as well as the other information in this filing before deciding to invest in our company. Any of the risk factors described below could significantly and adversely affect our business, prospects, financial condition and results of operations. Additional risks and uncertainties not currently known or that are currently considered to be immaterial may also materially and adversely affect our business, prospects, financial condition and results of operations. As a result, the trading price or value of our common stock could be materially adversely affected and you may lose all or part of your investment.

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

We have a limited operating history and expect to continue to incur losses for an indeterminable period of time.

We have a limited operating history and are engaged in the initial stages of exploration, development and exploitation of our leasehold acreage and will continue to be so until commencement of substantial production from our oil and natural gas properties, which will depend upon successful drilling results, additional and timely capital funding, and access to suitable infrastructure. Companies in their initial stages of development face substantial business risks and may suffer significant losses. We have generated substantial net losses and negative cash flows from operating activities in the past and expect to continue to incur substantial net losses as we continue our drilling program. In considering an investment in our common stock, you should consider that there is only limited historical and financial operating information available upon which to base your evaluation of our performance. In addition, the accompanying consolidated financial statements have been prepared on a going concern basis, which contemplates the realization of assets and liquidation of liabilities in the normal course of business. The Company has incurred losses from operations of $12,776,688 from the date of inception (February 9, 2011) through December 31, 2012. Additionally, the Company is dependent on obtaining additional debt and/or equity financing to roll-out and scale its planned principal business operations. These factors raise substantial doubt about the Company's ability to continue as a going concern. Management's plans in regard to these matters consist principally of seeking additional debt and/or equity financing combined with expected cash flows from current oil and gas assets held and additional oil and gas assets that it may acquire. There can be no assurance that the Company's efforts will be successful. The financial statements do not include any adjustments that may result from the outcome of this uncertainty. We face challenges and uncertainties in financial planning as a result of the unavailability of historical data and uncertainties regarding the nature, scope and results of our future activities. New companies must develop successful business relationships, establish operating procedures, hire staff, install management information and other systems, establish facilities and obtain licenses, as well as take other measures necessary to conduct their intended business activities. We may not be successful in implementing our business strategies or in completing the development of the infrastructure necessary to conduct our business as planned. In the event that one or more of our drilling programs is not completed or is delayed or terminated, our operating results will be adversely affected and our operations will differ materially from the activities described in this Annual Report. As a result of industry factors or factors relating specifically to us, we may have to change our methods of conducting business, which may cause a material adverse effect on our results of operations and financial condition. The uncertainty and risks described in this Annual Report 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 provided by our operating activities in the future.

Drilling for and producing oil and natural gas are highly speculative and involve a high degree of risk, with many uncertainties that could adversely affect our business. We have not recorded significant proved reserves, and areas that we decide to drill may not yield oil or natural gas in commercial quantities or at all.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes us from definitively predicting the costs involved and time required to reach certain objectives. Our potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation before they can be drilled. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and such costs can increase significantly due to various complications that may arise during the drilling and operating processes. Before a well is spud, we may incur significant geological and geophysical (seismic) costs, which are incurred whether a well eventually produces commercial quantities of hydrocarbons or is drilled at all. Exploration wells bear a much greater risk of loss than development wells. The analogies we draw from available data from other wells, more fully explored locations or producing fields may not be applicable to our drilling locations. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our operations as proposed and could be

forced to modify our drilling plans accordingly.

If we decide to drill a certain location, there is a risk that no commercially productive oil or natural gas reservoirs will be found or produced. We may drill or participate in new wells that are not productive. We may drill wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover exploration, drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from the well or abandonment of the well. Whether a well is ultimately productive and profitable depends on a number of additional factors, including the following:

- general economic and industry conditions, including the prices received for oil and natural gas;
- shortages of, or delays in, obtaining equipment, including hydraulic fracturing equipment, and qualified personnel;
- potential drainage by operators on adjacent properties;
- loss of or damage to oilfield development and service tools;
- problems with title to the underlying properties;
- increases in severance taxes;
- adverse weather conditions that delay drilling activities or cause producing wells to be shut down;
- domestic and foreign governmental regulations; and
- proximity to and capacity of transportation facilities.

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If we do not drill productive and profitable wells in the future, our business, financial condition and results of operations could be materially and adversely affected.

Our success is dependent on the prices of oil and natural gas. Low oil or natural gas prices and the substantial volatility in these prices may adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure requirements and financial obligations.

The prices we receive for our oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, 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. For example, for the four years ended December 31, 2012, the NYMEX — WTI oil price ranged from a high of $120.92 per Bbl to a low of $33.87 per Bbl, while the NYMEX — Henry Hub natural gas price ranged from a high of $8.26 per MMBtu to a low of $1.82 per MMBtu. 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. These factors include the following:

- the domestic and foreign supply of oil and natural gas;
- the domestic and foreign demand for oil and natural gas;
- the prices and availability of competitors' supplies of oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and state-controlled oil companies relating to oil price and production controls;
- the price and quantity of foreign imports of oil and natural gas;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil and natural gas futures contracts;
- localized supply and demand fundamentals, including the availability, proximity and capacity of gathering and transportation systems for natural gas;
- the availability of refining capacity;
- the prices and availability of alternative fuel sources;
- weather conditions and natural disasters;
- political conditions in or affecting oil and natural gas producing regions, including the Middle East and South America;
- the continued threat of terrorism and the impact of military action and civil unrest;
- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate hydraulic fracturing activities;
- the level of global oil and natural gas inventories and exploration and production activity;
- authorization of exports from the Unites States of liquefied natural gas;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and
- overall worldwide economic conditions.

Declines in oil or natural gas prices would not only reduce our revenue, but could reduce the amount of oil and natural gas that we can produce economically. Should natural gas or oil prices decrease from current levels and remain there for an extended period of time, we may elect in the future to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which would have a material adverse effect on our business, financial condition and results of operations.

Our exploration, development and exploitation projects require substantial capital expenditures that may exceed our cash flows from operations and potential borrowings, and we may be unable to obtain needed capital on satisfactory terms, which could adversely affect our future growth.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. The net proceeds we may receive from future debt and/or equity offerings, our operating cash flows and future potential borrowings may not be adequate to fund our future acquisitions or future capital expenditure requirements. The rate of our future growth may be dependent, at least in part, on our ability to access capital at rates and on terms we determine to be acceptable.

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

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;
- the prices at which we sell our production;
- the costs of developing and producing our oil and natural gas reserves;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

In addition, future events, such as terrorist attacks, wars or combat peace-keeping missions, financial market disruptions, general economic recessions, oil and natural gas industry recessions, large company bankruptcies, accounting scandals, overstated reserves estimates by major public oil companies and disruptions in the financial and capital markets have caused financial institutions, credit rating agencies and the public to more closely review the financial statements, capital structures and earnings of public companies, including energy companies. Such events have constrained the capital available to the energy industry in the past, and such events or similar events could adversely affect our access to funding for our operations in the future.

If our revenues decrease as a result of lower oil and 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, further develop and exploit our current properties or invest in additional exploration opportunities. Alternatively, a significant improvement in oil and natural gas prices or other factors could result in an increase in our capital expenditures and we may be required to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, the sale or farm out of interests in our assets, the borrowing of funds or otherwise to meet any increase in capital needs. If we are unable to raise additional capital from available sources at acceptable terms, our business, financial condition and results of operations could be adversely affected. Further, future debt financings may require that a portion of our cash flows provided by operating activities be used for the payment of principal and interest on our debt, thereby reducing our ability to use cash flows to fund working capital, capital expenditures and acquisitions. Debt financing may involve covenants that restrict our business activities. If we succeed in selling additional equity securities to raise funds, at such time the ownership percentage of our existing stockholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing stockholders. If we choose to farm-out interests in our prospects, we may lose operating control over such prospects.

Our oil and natural gas reserves are estimated and may not reflect the actual volumes of oil and natural gas we will receive, and significant inaccuracies in these reserves estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating accumulations of oil and natural gas is complex and is not exact, due to numerous inherent uncertainties. The process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions.

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The accuracy of any estimates of proved reserves generally increases with the length of the production history. Due to the limited production history of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data are available, the estimated proved reserves will be re-determined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance to our estimates could materially affect the quantities and present value of our reserves.

There is no guarantee that the proposed acquisition of the Mississippian asset will be completed, and the failure to acquire the Mississippian asset could adversely affect our business and results of operations.

We have signed a binding agreement to acquire 100% operated working interests in the Mississippian Lime covering approximately 7,006 gross (6,763 net) acres located in Kansas. We anticipate that the acquisition will occur during March 2013. However, the completion of the Mississippian acquisition is subject to customary closing conditions, and our ability to secure sufficient financing, of which there can be no assurances. We cannot guarantee that the acquisition will occur in March 2013 or at any time thereafter. The Mississippian asset represents a significant business opportunity for us and, if we fail to acquire the Mississippian asset, our anticipated business and results of operations could be adversely affected and there is no guarantee that we could subsequently acquire an equally attractive oil play.

We may have accidents, equipment failures or mechanical problems while drilling or completing wells or in production activities, which could adversely affect our business.

While we are drilling and completing wells or involved in production activities, we may have accidents or experience equipment failures or mechanical problems in a well that cause us to be unable to drill and complete the well or to continue to produce the well according to our plans. We may also damage a potentially hydrocarbon-bearing formation during drilling and completion operations. Such incidents may result in a reduction of our production and reserves from the well or in abandonment of the well.

Our operations are subject to operational hazards and unforeseen interruptions for which we may not be adequately insured.

There are numerous operational hazards inherent in oil and natural gas exploration, development, production and gathering, including:

- unusual or unexpected geologic formations;
- natural disasters;
- adverse weather conditions;
- unanticipated pressures;
- loss of drilling fluid circulation;
- blowouts where oil or natural gas flows uncontrolled at a wellhead;
- cratering or collapse of the formation;
- pipe or cement leaks, failures or casing collapses;
- fires or explosions;
- releases of hazardous substances or other waste materials that cause environmental damage;

pressures or irregularities in formations; and