PDC ENERGY, INC.
Form 10-K
February 21, 2014

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

FORM 10-K

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

For the fiscal year ended December 31, 2013

or

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

For the transition period from __________ to _________

Commission File Number 000-07246
PDC ENERGY, INC.
(Exact name of registrant as specified in its charter)

Nevada	95-2636730
(State of incorporation)	(I.R.S. Employer Identification No.)

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip code)

Registrant's telephone number, including area code: (303) 860-5800

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	NASDAQ Global Select Market

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

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

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 T

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 T No £

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§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 T No £

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2013 was $1.5 billion (based on the closing price of $51.48 per share as of the last business day of the fiscal quarter ending June 30, 2013).

As of February 7, 2014, there were 35,754,597 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

We hereby incorporate by reference into this document the information required by Part III of this Form, which will appear in our definitive proxy statement to be filed pursuant to Regulation 14A for our 2014 Annual Meeting of Stockholders.

PDC ENERGY, INC.
2013 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references in this report to "PDC Energy," "PDC," "the Company," "we," "us," "our" or "ours" refer to the registrant, PDC Energy, Inc. and all subsidiaries consolidated for the purposes of its financial statements, including our proportionate share of the financial position, results of operations, cash flows and operating activities of our affiliated partnerships and PDC Mountaineer, LLC ("PDCM"), a joint venture currently owned 50% each by PDC and Lime Rock Partners, LP. Unless the context otherwise requires, references in this report to "Appalachian Basin" refers to our operations in the Utica Shale in Ohio and Marcellus Shale in West Virginia and Pennsylvania, including PDC's proportionate share of our affiliated partnerships' and PDCM's assets, results of operations, cash flows and operating activities. See Note 1, Nature of Operations and Basis of Presentation, to our consolidated financial statements included elsewhere in this report for a description of our consolidated subsidiaries.

GLOSSARY OF UNITS OF MEASUREMENTS AND INDUSTRY TERMS

Units of measurements and industry terms are defined in the Glossary of Units of Measurements and Industry Terms, included at the end of this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: estimated crude oil, natural gas and natural gas liquids (“NGLs”) reserves; future production (including the components of such production), sales, expenses, cash flows and liquidity; our evaluation method of our customers' and derivative counterparties' credit risk is appropriate and consistent with those used by other market participants; anticipated capital projects, expenditures and opportunities; future exploration, drilling and development activities; our drilling programs and number of locations; expected timing of additional drilling rigs in the Wattenberg Field and Utica Shale; availability of additional midstream facilities and services, timing of that availability and related benefits to us; availability of sufficient funding for our 2014 capital program and sources of that funding; expected 2014 capital budget allocations; acquisitions of additional Utica Shale acreage; expected use of the remaining net proceeds from our August 2013 equity offering; the impact of high line pressures; compliance with debt covenants; expected funding sources for conversion of our 3.25% convertible senior notes due 2016; compliance with government regulations; potential future transactions; the borrowing base under our credit facility; impact of litigation on our results of operations and financial position; effectiveness of our derivative program in providing a degree of price stability; that we do not expect to pay dividends in the foreseeable future; and our future strategies, plans and objectives.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including known and unknown risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of crude oil, natural gas and NGLs, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements.

Important factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- changes in worldwide production volumes and demand, including economic conditions that might impact demand;
- volatility of commodity prices for crude oil, natural gas and NGLs;
- the impact of governmental policies and/or regulations, including changes in environmental and other laws, the interpretation and enforcement related to those laws and regulations, liabilities arising thereunder and the costs to comply with those laws and regulations;
- potential declines in the value of our crude oil, natural gas and NGLs properties resulting in impairments;
- changes in estimates of proved reserves;
- inaccuracy of reserve estimates and expected production rates;
- potential for production decline rates from our wells being greater than expected;
- timing and extent of our success in discovering, acquiring, developing and producing reserves;
- our ability to secure leases, drilling rigs, supplies and services at reasonable prices;
- availability of sufficient pipeline, gathering and other transportation facilities and related infrastructure to process and transport our production, particularly in the Wattenberg Field and the Utica Shale, and the impact of these facilities and regional capacity on the prices we receive for our production;
- timing and receipt of necessary regulatory permits;
- risks incidental to the drilling and operation of crude oil and natural gas wells;
- our future cash flows, liquidity and financial condition;
- competition within the oil and gas industry;

- availability and cost of capital;
- reductions in the borrowing base under our revolving credit facility;
- our success in marketing crude oil, natural gas and NGLs;
- effect of natural gas and crude oil derivatives activities;
- impact of environmental events, governmental and other third-party responses to such events, and our ability to insure adequately against such events;
- cost of pending or future litigation;
- effect that acquisitions we may pursue have on our capital expenditures;
- our ability to retain or attract senior management and key technical employees; and
- success of strategic plans, expectations and objectives for our future operations.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, Risk Factors, made in this report and our other filings with the U.S. Securities and Exchange Commission ("SEC") for further information on risks and uncertainties that could affect our business, financial condition, results of operations and cash flows. We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events. All forward-looking statements are qualified in their entirety by this cautionary statement.

ITEMS 1. AND 2. BUSINESS AND PROPERTIES

The Company

We are a domestic independent exploration and production company that produces, develops, acquires and explores for crude oil, natural gas and NGLs with primary operations in the Wattenberg Field in Colorado, the Utica Shale in southeastern Ohio and the Appalachia-Marcellus Shale in northern West Virginia. Our operations in the Wattenberg Field are focused on the liquid-rich horizontal Niobrara and Codell plays. We are currently focusing our Ohio development activity in the liquid-rich portion of the Utica Shale play and are pursuing horizontal development in the Marcellus Shale in West Virginia through our 50% joint venture interest in PDCM. We own an interest in approximately 3,100 gross producing wells, of which 249 are horizontal. Production of 7.4 MMboe from continuing operations for the year ended December 31, 2013 represents an increase of 35% compared to the year ended December 31, 2012. For the month ended December 31, 2013, we maintained an average production rate of 27 MBoe per day. As of December 31, 2013, we had approximately 266 MMBoe of proved reserves with a pre-tax present value of future net revenues (“PV-10”) of $2.7 billion, representing an increase of 73 MMBoe and $1.0 billion, respectively, relative to the totals as of December 31, 2012. The percentage of our proved reserves represented by crude oil and NGLs rose to 54% as of December 31, 2013, up from 48% as of December 31, 2012. PV-10 is not a financial measure under Accounting Principles Generally Accepted in the United States of America (“U.S. GAAP”). See Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to our standardized measure.

The increase in our estimated proved reserves and production is primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Future development of the Wattenberg Field provides the opportunity to add further proved, probable and possible ("3P") reserves to our portfolio through continued delineation and downspacing of the horizontal Niobrara and Codell formations. Recently, we completed and are producing from our first 16 horizontal wells per section downspacing project in the Wattenberg Field. In 2013, we spudded 70 horizontal wells in the Wattenberg Field, 54 of which were completed, and participated in 49 gross, 10.4 net, horizontal non-operated drilling projects. Our year-end 2013 proved reserves include reserves associated with our

Utica Shale properties, where we have acquired approximately 48,000 net acres. We spudded 11 horizontal Utica wells in 2013, nine of which were completed and connected to a gathering line. PDCM spudded 14 horizontal Marcellus wells in 2013, 10 of which were completed as of year-end.

The following table presents our proved reserve estimates as of December 31, 2013 based on a reserve report prepared by Ryder Scott Company, L.P. (“Ryder Scott”), our independent petroleum engineering consulting firm:

	Proved Reserves at December 31, 2013					
	Proved Reserves (MMBoe)	% of Total Proved Reserves	% Proved Developed	% Liquids	Proved Reserves to Production Ratio (in years)	Production (MBoe)
Wattenberg Field	212	79.7 %	29.7 %	64.0 %	35.7	5,938
Utica Shale	14	5.4 %	23.8 %	48.6 %	63.8	225
Appalachia-Marcellus Shale	40	14.9 %	23.3 %	— %	31.2	1,266
Total proved reserves	266	100.0 %	28.4 %	53.6 %	35.8	7,430

Our Strengths

- Multi-year project inventory in premier crude oil, natural gas and NGLs plays. We have a significant operational presence in three key U.S. onshore basins and have identified a substantial inventory of approximately 3,600 gross horizontal drilling projects, as well as a substantial number of refracture and recompletion opportunities. This inventory of horizontal drilling projects includes approximately 2,800 projects in the Wattenberg Field, 200 projects in the Utica Shale and 600 projects in the Marcellus Shale.

- Track record of reserve and production growth. Our proved reserves have grown from 55 MMBoe at December 31, 2008 to approximately 266 MMBoe at December 31, 2013, representing a compound annual growth rate ("CAGR") of 37%. During the same time period, our proved crude oil and NGL reserves grew at a CAGR of 57%. Our annual production from continuing operations grew from 3.2 MMBoe in 2008 to 7.4 MMBoe in 2013, representing a CAGR of 18%.

- Horizontal drilling and completion experience. We have a proven track record of applying technical expertise toward developing unconventional resources through horizontal drilling and completion operations, having drilled or participated in 249 horizontal wells, including 144 horizontal wells during the year ending December 31, 2013. We have transitioned to multi-well pad drilling to further optimize costs and enhance horizontal drilling efficiencies. Pad drilling enables us to streamline the transition to increased well density in all our horizontal plays.

- Access to liquidity. As of December 31, 2013, we had a total liquidity position of $647.0 million, comprised of $193.2 million of cash and cash equivalents and $453.8 million available for borrowing under revolving credit facilities. In August 2013, we completed a public offering of 5,175,000 shares of our common stock, at a price to us of $53.37 per share, for net proceeds of approximately $276 million, after deducting offering expenses and underwriting discounts. We expect to use the remaining net proceeds from the offering to fund a portion of our 2014 capital program and for general corporate purposes. We have no near-term debt maturities and have had no draws on our revolving credit facility since June 2013.

- Cash flow management through commodity derivative instruments. We actively hedge our future exposure to commodity price fluctuations by entering into oil and natural gas swaps, collars and basis protection swaps to the extent possible. As of December 31, 2013, we have hedged approximately 4,112 MBbls of our crude oil production for 2014 at a weighted-average minimum price of $89.06 per Bbl and a weighted-average maximum price of $94.01 per Bbl. As of December 31, 2013, we have hedged approximately 20 Bcf of our natural gas production in 2014 at a weighted-average minimum price of $4.03 per Mcf.

- Significant operational control in our core areas. As a result of successfully executing our strategy over time of acquiring largely concentrated acreage positions with a high working interest, we operate and manage approximately 91% of the wells in which we have an interest. Our high percentage of operated properties enables us to exercise a significant level of control with respect to drilling, production, operating and administrative costs, in addition to leveraging our base of technical expertise in our core operating areas.

- Management experience and operational expertise. We have a management team with a proven track record of drilling performance and a technical and operational staff with significant expertise in the basins in which we operate, particularly in horizontal drilling, completion and production activities.

Business Strategy

Our long-term business strategy focuses on generating shareholder value through the acquisition, exploration and development of crude oil and natural gas properties; we are currently focused on the organic growth of our reserves, production and cash flows in our high-value, horizontal drilling programs after having completed multiple transactions to restructure and simplify our property portfolio over the last several years. Additionally, we pursue various midstream, marketing and cost reduction initiatives designed to increase our per unit operating margins and we maintain a conservative and disciplined financial strategy focused on providing sufficient liquidity and balance sheet strength to execute our business strategy.

Development drilling

Our leasehold interests consist of developed and undeveloped crude oil, natural gas and NGLs resources. Based upon our current acreage holdings, we have identified a substantial inventory of approximately 3,600 gross capital projects for horizontal development, primarily in high-return, liquid-rich plays. We have established a capital budget of $631 million for 2014 for drilling in the Wattenberg Field and the Utica Shale and for other miscellaneous projects. Additionally, PDCM has established a capital budget for the Marcellus Shale, of which $16 million is our proportionate share.

Wattenberg Field. Our primary focus in the Wattenberg Field is drilling in the horizontal Niobrara and Codell plays. We have transitioned to multi-well pad drilling to further optimize costs and enhance horizontal drilling efficiencies in the field. Depending upon commodity prices and the number of drilling rigs operating, we believe that our inventory of approximately 2,800 gross 3P horizontal projects in the field, together with refracturing and vertical Codell well opportunities, provides us with over 20 years of drilling activity. Approximately $467 million of our 2014 capital budget is expected to be spent on development activities in the field, the majority of which is expected to be invested in an expanded horizontal Niobrara and Codell drilling program. We plan to run a four-rig program through the first quarter of 2014 and add a fifth drilling rig during the second quarter. Approximately $100 million of the total Wattenberg Field capital budget is allocated for non-operated horizontal drilling projects. We expect to drill and operate approximately 115 horizontal Niobrara or Codell wells and expect to participate in approximately

75 to 100 non-operated horizontal opportunities in 2014.

Utica Shale. We continue to delineate and develop our leasehold position in the Utica Shale. We currently estimate that we have approximately 200 gross projects for horizontal drilling in the Utica Shale and have spudded 13 horizontal wells through December 31, 2013. We are currently running a one-rig program in the Utica Shale and plan on adding a second drilling rig during the second half of 2014. In 2014, we expect to devote approximately $162 million of our 2014 capital program toward drilling and completion activity and acquisition of additional acreage in the Utica Shale. We plan to drill 18 horizontal wells targeting the wet gas and condensate windows of the play in 2014.
Appalachia-Marcellus Shale. In 2013, PDCM drilled 14 gross (7 net) and completed 10 gross (5 net) horizontal wells in the Marcellus Shale and constructed various midstream assets to gather and compress its Marcellus gas. We currently estimate that we have approximately 600 gross projects for horizontal drilling in the Marcellus Shale. PDCM has elected to temporarily suspend drilling activities in the Marcellus Shale. In 2014, PDCM currently expects to focus on completion operations on the remaining four horizontal wells that were in-process as of December 31, 2013 and on the continued development of midstream infrastructure.

Strategic acquisitions

We typically pursue the acquisition of assets that have a balance of value in producing wells, behind-pipe reserves and high-quality undeveloped drilling locations. We seek liquid-rich properties with large undeveloped drilling upside where we believe we can utilize our operational abilities to add shareholder value. We have an experienced team of management, engineering, geosciences and commercial professionals who identify and evaluate acquisition opportunities.

Wattenberg Field. In June 2012, we acquired certain assets from affiliates of Merit Energy (the "Merit Acquisition") for an aggregate purchase price of $304.6 million. The acquired assets comprise approximately 30,000 net acres located almost entirely in the core Wattenberg Field and in close proximity to our then-existing acreage position. Following the closing of the Merit Acquisition, our total position in the core Wattenberg Field is now approximately 97,000 net acres.

Utica Shale. Since 2011, we have acquired approximately 48,000 net acres of Utica leaseholds, targeting the crude oil and wet natural gas windows of the Utica Shale play throughout southeastern Ohio. As an early entrant into the development of the Utica Shale, we believe we have gained valuable experience and expertise in proactively addressing title and other issues associated with the development of the play.

Appalachia-Marcellus Shale. In October 2011, PDCM acquired 100% of the membership interests of Seneca-Upshur Petroleum, LLC ("Seneca-Upshur") for $139.2 million, of which our proportionate share was $69.6 million. The acquisition included approximately 1,340 gross wells producing natural gas from the shallow Upper Devonian Shale formation and all rights and depths to an estimated 100,000 net acres in West Virginia, of which 90,000 acres are prospective for the Marcellus Shale.

Strategic divestitures

We continue to seek ways to optimize our asset portfolio as part of our business strategy. This may include divesting lower return assets and reinvesting in our stronger economic inventory. As a result, we have divested several assets over the past few years.

Colorado Dry Gas Assets. In June 2013, we completed the sale of our non-core Colorado dry gas assets, primarily natural gas producing properties located in the Piceance Basin, northeastern Colorado and other non-core areas, to certain affiliates of Caerus Oil and Gas LLC ("Caerus") for consideration of $177.6 million, with an additional $17 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. The proceeds from the asset disposal were used to pay down our revolving credit facility and to fund a portion of our 2013 capital budget.

Appalachian Shallow Upper Devonian Gas Assets. In October 2013, we executed a purchase and sale agreement for the sale of substantially all our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties owned directly by us, as well as through our proportionate share of PDCM. The properties consisted of approximately 3,500 gross shallow producing wells, related facilities and associated leasehold acreage, limited to the Upper Devonian and shallower formations. Substantially all of the divestiture closed in December 2013 for aggregate consideration of approximately $20.6 million, of which our share of the proceeds was approximately $5.1 million, subject to certain post-closing adjustments. Concurrent with the closing of the transaction, our $6.7 million irrevocable standby letter of credit and an agreement for firm transportation services were released and novated to the buyer. We retained all zones, formations and intervals below the Upper Devonian formation, including the Marcellus Shale, Utica Shale and Huron Shale, as well as all Marcellus-related midstream assets.

Permian Basin. During the fourth quarter of 2011, we completed the sale of certain non-core Permian assets for a total of $13.2 million. In December 2011, we executed a purchase and sale agreement with a subsidiary of Concho Resources Inc. ("COG"), for the sale of our remaining Permian Basin assets and closed the transaction in February 2012. Total proceeds received were $189.2 million.

Operational and financial risk management

We focus on horizontal development drilling programs in resource plays that offer repeatable results capable of driving growth in reserves, production and cash flows. We periodically review acquisition opportunities in our core areas of operation as we believe we can extract additional value from such assets through production optimization, refracturing, recompletions and development drilling. In addition, core acquisitions can potentially provide synergies that result in economies of scale from a combined position. While we believe development drilling will remain the foundation of our capital programs, we expect to continue our disciplined approach to acquisitions and exploratory drilling.

We proactively employ strategies to help reduce the financial risks associated with our industry. One such strategy is to maintain a balanced production mix of liquids and natural gas. During 2013, we produced crude oil, natural gas and NGLs with a production mix of approximately 53% liquids and 47% natural gas. This strategy of a diversified commodity mix helps mitigate the financial impact from a decline in the market price of any one of our commodities. In addition, we utilize commodity-based derivative instruments to manage a substantial portion of our exposure to price volatility with regard to our crude oil and natural gas sales and natural gas marketing. As of December 31, 2013, we had natural gas and crude oil derivative positions in place for 2014 covering approximately 4,112 MBbls of our crude oil production and approximately 20 Bcf of our natural gas production. Currently, we do not hedge our NGL production. See Part II, Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for a detailed summary of our open derivative positions.

Selective exploration

Historically, we have pursued a disciplined exploration program intended to replenish our portfolio and to position us for production and reserve growth in future years. Our efforts have focused on liquid-rich plays to take advantage of the attractive economics associated with crude oil and NGL-weighted projects. We have attempted to identify potential plays in their early stages in order to accumulate significant leasehold positions prior to competitive forces driving up the cost of entry and to invest in leasehold positions that were in the proximity of existing or emerging midstream infrastructure. The Utica Shale was our primary exploration focus during the past few years. Our operations in the Utica Shale have now shifted to developmental drilling and delineation. We do not expect significant exploration activity in 2014, as our main focus is expected to be on organic growth through developmental drilling.

Business Segments

We divide our operating activities into two segments: (1) Oil and Gas Exploration and Production and (2) Gas Marketing.

Oil and Gas Exploration and Production

Our Oil and Gas Exploration and Production segment primarily reflects revenues and expenses from the production and sale of crude oil, natural gas and NGLs. The prices we receive for our crude oil, natural gas and NGLs vary based on the terms of applicable purchase contracts.

- Crude oil. We do not refine any of our crude oil production. In the Wattenberg Field, crude oil is sold at each individual well site and transported by the purchasers via truck, pipeline or rail to local and non-local markets under various purchase contracts with monthly pricing provisions based on a differential to the average monthly NYMEX price. In the Utica Shale, crude oil and condensate is sold to local purchasers at each individual well site based on a differential to the average monthly NYMEX price and is typically transported by the purchasers via truck to local refineries, rail facilities or barge loading terminals on the Ohio River. We currently have no long-term firm transportation agreements related to our crude oil production.

- Natural gas. We primarily sell our natural gas to midstream service providers, marketers, utilities, industrial end-users and other wholesale purchasers. We generally sell the natural gas that we produce under contracts with indexed or NYMEX monthly pricing provisions, with the remaining production sold under contracts with daily pricing provisions. Virtually all of our contracts include provisions whereby prices change monthly with changes in the market, with certain adjustments that may be made based on whether a well delivers to a gathering or transmission line and the quality of the natural gas. Therefore, the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. In certain instances, we enter into firm transportation, processing and sales agreements to provide for pipeline capacity to flow and sell a portion of our natural gas volumes. In some cases, in order to meet pipeline specifications, our natural gas must be processed before we can transport it. We also have interruptible transportation agreements in place in certain areas where adequate transportation capacity is believed to be available. We may also enter into firm sales agreements to ensure that we are selling to a purchaser who has contracted for pipeline capacity. See Note 11, Commitments and Contingencies - Firm Transportation, Processing and Sales Agreements, to our consolidated financial statements included elsewhere in this report for a discussion of our long-term firm sales, processing and transportation agreements for pipeline capacity. In the Wattenberg Field, the majority of our leasehold is dedicated to our primary midstream provider, DCP Midstream, which gathers and processes wet natural gas produced in the basin and sells our residue gas to various markets. In the Utica Shale, wet natural gas produced in our northern acreage is gathered and processed pursuant to a firm transportation agreement with Markwest Utica EMG while wet natural gas produced in our southern acreage is gathered and processed by Blue Racer Midstream LLC. We market our Utica residue gas to various purchasers based on pipeline basis or NYMEX pricing. In the Appalachia-Marcellus Shale, our dry natural gas is gathered and transported to a market hub pursuant to a firm transportation agreement with Equitrans LP and an interruptible agreement with Momentum. We sell the dry natural gas to various marketers at a price primarily based on spot gas delivered to the Texas Eastern Transmission pipeline M-2 point, less transportation costs.

NGLs. We produce NGLs in the Wattenberg Field and Utica Shale. In the Wattenberg Field, the majority of our NGLs are sold at the tailgate of DCP Midstream processing plants based on prices of NGL deliveries to the Conway hub in Kansas. In the Utica Shale, the majority of our NGLs are fractionated and marketed by Markwest Utica EMG and Blue Racer Midstream LLC and sold based on month-to-month pricing in various markets. Our NGL production is sold under both short- and long-term purchase contracts.

We enter into financial derivatives in order to reduce the impact of possible price volatility regarding the physical sales market. See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations: Results of Operations - Commodity Price Risk Management, Net, Natural Gas and Crude Oil Derivative Activities, Item 7A, Quantitative and Qualitative Disclosures about Market Risk, and Note 4, Derivative Financial Instruments, to our consolidated financial statements included elsewhere in this report.

Our Oil and Gas Exploration and Production segment also reflects revenues and expenses related to well operations and pipeline services. We are paid a monthly operating fee for the portion of each well we operate that is owned by others, including our affiliated partnerships. We believe the fee is competitive with rates charged by other operators in the area. As we acquire the working interest of our non-affiliated investor partners in our affiliated partnerships, revenues related to well operations and pipeline services will decrease.

We construct, own and operate gathering systems in our Appalachia-Marcellus Shale operations. Pipelines and related facilities can represent a significant portion of the capital costs of developing wells, particularly in new areas located at a distance from existing pipelines. We consider these costs in the evaluation of our leasing, development and acquisition opportunities.

Our natural gas is transported through our own and third-party gathering systems and pipelines and we incur gathering, processing and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based upon the volume and distance shipped, as well as the fee charged by the third-party processor or transporter. Like most producers, we rely on our third-party midstream service providers to construct compression, gathering and processing facilities to keep pace with our production growth. As a result, the timing and availability of additional facilities going forward is beyond our control. Capacity on these gathering systems and pipelines is occasionally reduced due to operational issues, repairs or improvements. A portion of our natural gas is transported under interruptible contracts and the remainder under firm transportation agreements, either directly with our subsidiary Riley Natural Gas ("RNG"), or through third-party processors or marketers. Therefore, interruptions in natural gas sales could result if pipeline space is constrained. Our Wattenberg Field production was adversely impacted by high line pressures on the gathering system operated by DCP Midstream during the spring and summer months of 2012 and 2013. We, and other operators in the field, are working closely with DCP Midstream in the Wattenberg Field, which is implementing a multi-year facility expansion program. The program is increasing midstream system capacity and helping to mitigate the impact of increased production volumes on system pressures. Although we expect system pressures to fluctuate and constrain production from time to time, we believe that this expansion will provide the additional gathering and processing capacity in the system necessary to increase our confidence that we can continue to produce and market our production.

See Part II, Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations, Summary Operating Results, for production, sales, pricing and lifting cost data.

Gas Marketing

Our Gas Marketing segment is comprised solely of the operating activities of RNG. RNG specializes in the purchase, aggregation and sale of natural gas production in the Utica Shale and Appalachia-Marcellus Shale. RNG purchases for resale natural gas produced by third-party producers, as well as natural gas produced by us and PDCM. The natural gas is marketed to third-party marketers, natural gas utilities and industrial and commercial customers, either directly through our gathering system or through transportation services provided by regulated interstate/intrastate pipeline companies.

For additional information regarding our business segments, see Note 17, Business Segments, to our consolidated financial statements included elsewhere in this report.

Areas of Operations

The following map presents the general locations of our development and production activities as of December 31, 2013.

- Wattenberg Field area, DJ Basin, Colorado. Currently, horizontal wells drilled in this area target the reservoirs in the Codell and Niobrara formations where we have acquired approximately 97,000 net acres. These horizontal wells have a vertical depth ranging from approximately 6,500 to 7,500 feet, with lateral lengths of approximately 4,000 to 5,000 feet. Pad drilling enables us to streamline the transition to increased well density in the horizontal Niobrara and Codell plays and optimize costs. We currently estimate that we have 2,800 gross horizontal capital projects in the Wattenberg Field in inventory, as well as other refracture and vertical Codell well opportunities.

- Utica Shale area, southeastern Ohio. Wells drilled in this area primarily target the Point Pleasant member of the Utica Shale formation. We have acquired approximately 48,000 net acres targeting the condensate and wet natural gas windows of the Utica Shale play throughout southeastern Ohio and we currently estimate that we have approximately 200 gross projects for horizontal drilling in the Utica Shale. The horizontal wells have a vertical depth ranging from approximately 7,000 to 8,000 feet, with lateral lengths of approximately 4,000 to 7,500 feet.

- Appalachia-Marcellus Shale area, West Virginia. Wells drilled in this area are primarily horizontal wells targeting the Marcellus Shale. PDCM has approximately 66,000 net acres prospective for the Marcellus Shale. PDCM is primarily focused on horizontal drilling and has approximately 600 gross Marcellus Shale drilling locations on the West Virginia acreage. These horizontal wells have a vertical depth ranging from approximately 7,000 to 8,000 feet, with lateral lengths of approximately 4,000 to 6,500 feet.

In December 2013, PDCM closed on a transaction pursuant to which substantially all of the wells producing from the shallow Upper Devonian Shale formation (non-Marcellus Shale) were sold.

Properties

Productive Wells

The following table presents our productive wells:

	Productive Wells As of December 31, 2013					
	Crude Oil		Natural Gas		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	207	138.1	2,497	2,156.7	2,704	2,294.8
Utica Shale	10	7.7	3	3.0	13	10.7
Appalachia-Marcellus Shale	—	—	374	140.5	374	140.5
Total productive wells	217	145.8	2,874	2,300.2	3,091	2,446.0

Proved Reserves

Our proved reserves are sensitive to future crude oil, natural gas and NGLs sales prices and the related effect on the economic productive life of producing properties. Increases in commodity prices may result in a longer economic productive life of a property or result in recognition of more economically viable proved undeveloped reserves. Decreases in commodity prices may result in negative impacts of this nature.

All of our proved reserves are located onshore in the U.S. Our proved reserve estimates are prepared using the definitions for proved reserves set forth in SEC Regulation S-X, Rule 4-10(a) and applicable SEC staff regulations, interpretations and guidance. As of December 31, 2013, all of our proved reserves, including the reserves of all subsidiaries consolidated for the purposes of our financial statements, have been estimated by Ryder Scott.

We have a comprehensive process that governs the determination and reporting of our proved reserves. As part of our internal control process, our reserves are reviewed annually by an internal team composed of reservoir engineers, geologists and accounting personnel for adherence to SEC guidelines through a detailed review of land records, available geological and reservoir data, as well as production performance data. The process includes a review of applicable working and net revenue interests and cost and performance data. The internal team compiles the reviewed data and forwards the data to the independent engineering firm engaged to estimate our reserves.

Our proved reserve estimates as of December 31, 2013 were based on a reserve report prepared by Ryder Scott. When preparing our reserve estimates, Ryder Scott did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, production volumes, well test data, historical costs of operations and development, product prices or any agreements relating to current and future operations of properties and sales of production.

Ryder Scott prepares an estimate of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined pursuant to acceptable industry methods and with a level of detail we deem appropriate. The final estimated reserve report is reviewed by our engineering staff and management prior to issuance by Ryder Scott.

The professional qualifications of the internal lead engineer primarily responsible for overseeing the preparation of our reserve estimates qualify the engineer as a Reserves Estimator, as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers. This position is currently being held by an employee who holds a Bachelor of Science degree in Petroleum and Chemical Refining Engineering with a minor in Petroleum Engineering, has over 36 years of experience in reservoir engineering, is a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers and is a registered Professional Engineer in the State of Colorado.

The SEC's reserve rule has expanded the technologies that a registrant may use to establish reserves. The SEC now allows use of techniques that have been proved effective by actual production from projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

All of our proved undeveloped reserves conform to the SEC five-year rule requirement as all proved undeveloped locations are scheduled, according to an adopted development plan, to be drilled within five years of each location’s initial booking date.

We used a combination of production and pressure performance, wireline wellbore measurements, offset analogies, seismic data and interpretation, wireline formation tests, geophysical logs and core data to calculate our reserve estimates, including the material additions to the 2013 reserve estimates.

Reserve estimates involve judgments and cannot be measured exactly. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. Neither the estimated future net cash flows nor the standardized measure of discounted future net cash flows ("standardized measure") is intended to represent the current market value of our proved reserves. For additional information regarding both of these measures, as well as other information regarding our proved reserves, see the unaudited Supplemental Information - Crude Oil and Natural Gas Information provided with our consolidated financial statements included elsewhere in this report. The following tables provide information regarding our estimated proved reserves:

	As of December 31, 2013	2012 (3)(4)	2011 (3)(4)(5)
Proved reserves			
Crude oil and condensate (MMBbls)	94	59	38
Natural gas (Bcf)	740	604	672
NGLs (MMBbls)	49	33	20
Total proved reserves (MMBoe)	266	193	169
Proved developed reserves (MMBoe)	76	82	79
Estimated future net cash flows (in millions) (1)	$4,323	$2,756	$2,290
PV-10 (in millions) (2)	$2,704	$1,709	$1,350
Standardized measure (in millions)	$1,782	$1,168	$941

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(1) Amount represents undiscounted pre-tax future net cash flows estimated by Ryder Scott of approximately $6.4 billion, $4.0 billion and $3.2 billion as of December 31, 2013, 2012 and 2011, respectively, less an internally estimated future income tax expense of approximately $2.1 billion, $1.2 billion and $0.9 billion, respectively.

(2) PV-10 is a non-U.S. GAAP financial measure. This non-U.S. GAAP measures is not a measure of financial or operating performance under U.S. GAAP and it is not intended to represent the current market value of our estimated reserves. PV-10 should not be considered in isolation or as a substitute for the standardized measure reported in accordance with U.S. GAAP, but rather should be considered in addition to the standardized measure. See Part I, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Reconciliation of Non-U.S. GAAP Financial Measures, for a definition of PV-10 and a reconciliation of our PV-10 value to the standardized measure.

(3) Includes estimated reserve data related to our Piceance and NECO assets which were divested in June 2013. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Piceance and NECO assets.

The following table sets forth information regarding estimated proved reserves for our Piceance and NECO assets:

	As of December 31, 2012	2011
Proved reserves		
Crude oil and condensate (MMBbls)	0.1	0.4
Natural gas (Bcf)	84	354
Total proved reserves (MMBoe)	14	59
Proved developed reserves (MMBoe)	14	24
Estimated future net cash flows (in millions)	$43	$32

(4) Includes estimated reserve data related to our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties, which were divested in December 2013. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to these assets.

The following table sets forth information regarding estimated proved reserves for our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties:

	As of December 31, 2012	2011
Proved reserves		
Natural gas (Bcf)	11	20

Total proved reserves (MMBoe)	2	3
Proved developed reserves (MMBoe)	2	3
Estimated future net cash flows (in millions)	$3	$15

(5) Includes estimated reserve data related to our Permian assets, which were classified as held for sale as of December 31, 2011 and divested in February 2012. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Permian assets.

The following table sets forth information regarding estimated proved reserves for our Permian assets:

	December 31, 2011
Proved reserves	
Crude oil and condensate (MMBbls)	8
Natural gas (Bcf)	6
NGLs (MMBbls)	2
Total proved reserves (MMBoe)	11
Proved developed reserves (MMBoe)	3
Estimated future net cash flows (in millions)	$348

The following table presents our estimated proved developed and undeveloped reserves as of December 31, 2013:

	As of December 31, 2013					
Operating Region/Area	Crude Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Crude Oil Equivalent (MBoe)	Percent	
Proved developed						
Wattenberg Field	22,611	155,797	14,360	62,937	83	%
Utica Shale	1,385	9,412	465	3,419	5	%
Appalachia-Marcellus Shale	1	55,178	—	9,197	12	%
Total proved developed	23,997	220,387	14,825	75,553	100	%
Proved undeveloped						
Wattenberg Field	66,481	302,272	32,073	148,933	78	%
Utica Shale	3,352	34,936	1,773	10,947	6	%
Appalachia-Marcellus Shale	—	182,045	—	30,341	16	%
Total proved undeveloped	69,833	519,253	33,846	190,221	100	%
Proved reserves						
Wattenberg Field	89,092	458,069	46,433	211,870	80	%
Utica Shale	4,737	44,348	2,238	14,366	5	%
Appalachia-Marcellus Shale	1	237,223	—	39,538	15	%
Total proved reserves	93,830	739,640	48,671	265,774	100	%

Developed and Undeveloped Acreage

The following table presents our developed and undeveloped lease acreage:

	As of December 31, 2013					
	Developed		Undeveloped (1)		Total	
Operating Region/Area	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	99,000	88,700	9,300	7,900	108,300	96,600
Utica Shale	2,400	2,000	50,300	45,900	52,700	47,900
Appalachia-Marcellus Shale	147,250	60,250	12,800	5,250	160,050	65,500
Total acreage	248,650	150,950	72,400	59,050	321,050	210,000

(1) With the exception of our properties prospective for the Utica Shale, substantially all of our undeveloped acreage is related to leaseholds that are held by production. Approximately 3%, 5.6% and 16.5% of our undeveloped leaseholds expire during 2014, 2015 and 2016, respectively.

Drilling Activity

The following table presents information regarding the number of wells drilled or participated in and the number of wells for which refractures and/or recompletions were performed:

	Drilling Activity Year Ended December 31,					
	2013		2012		2011	
Operating Region	Gross	Net	Gross	Net	Gross	Net
Wattenberg Field	119	69.2	57	39.0	145	99.6
Utica Shale	11	9.2	3	2.5	1	0.8
Appalachia-Marcellus Shale	14	7.0	3	1.5	6	2.9
Other (1)(2)	—	—	—	—	43	41.5
Total wells drilled	144	85.4	63	43.0	195	144.8
Refractures and recompletions (3)	5	4.1	85	79.9	192	177.6

(1) Includes drilling activity in Piceance and NECO operating regions, which were divested in June 2013. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Piceance and NECO assets.

(2) Includes drilling activity in the Permian Basin operating region, which were divested in February 2012. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Permian assets.

(3) Substantially all of the refractures and recompletions occurred in the Wattenberg Field.

The following tables set forth our developmental and exploratory well drilling activity. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of wells spudded, turned-in-line and producing during the period. In-process wells represent wells that are in the process of being drilled or have been drilled and are waiting to be fractured and/or for gas pipeline connection as of the date shown.

	Net Development Well Drilling Activity Year Ended December 31,								
	2013			2012			2011		
Operating Region/Area	Productive	In-Process (3)	Dry	Productive	In-Process	Dry	Productive	In-Process	Dry
Wattenberg Field	53.5	15.6	0.1	31.3	7.7	—	86.5	13.1	—
Utica Shale	3.0	2.0	—	—	—	—	—	—	—
Appalachia-Marcellus Shale	3.5	2.0	—	1.5	—	—	0.9	2.0	—
Other (1)(2)	—	—	—	—	—	—	28.5	8.5	2.0
Total net development wells	60.0	19.6	0.1	32.8	7.7	—	115.9	23.6	2.0

(1) Our Piceance and NECO assets were divested in June 2013. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Piceance and NECO assets.

(2)

As of December 31, 2011, our Permian assets were held for sale and subsequently divested in February 2012. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Permian assets.

(3) On a gross basis, wells in-process as of December 31, 2013 consisted of 32 wells in the Wattenberg Field, 2 wells in the Utica Shale and 4 wells in the Appalachia-Marcellus Shale.

	Net Exploratory Well Drilling Activity								
	Year Ended December 31,								
	2013			2012			2011		
Operating Region/Area	Productive	In-Process	Dry	Productive	In-Process	Dry	Productive	In-Process	Dry
Utica Shale	4.2	—	—	—	1.5	1.7	—	2.3	—
Appalachia-Marcellus Shale	1.5	—	—	—	—	—	—	—	—
Other	—	—	—	—	—	—	—	1.0	—
Total net exploratory wells	5.7	—	—	—	1.5	1.7	—	3.3	—

Title to Properties

We believe that we hold good and defensible leasehold title to substantially all of our crude oil and natural gas properties in accordance with standards generally accepted in the industry. As is customary in the industry, a preliminary title examination is typically conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial curative work is performed with respect to discovered defects which we deem to be significant. Title examinations have been performed with respect to substantially all of our producing properties.

The properties we own are subject to royalty, overriding royalty and other outstanding interests customary in the industry. The properties may also be subject to additional burdens, liens or encumbrances customary in the industry, including items such as operating agreements, current taxes, development obligations under crude oil and natural gas leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with our use of the properties.

Substantially all of our crude oil and natural gas properties, excluding properties held by PDCM and our share of the limited partnerships that we sponsor, have been mortgaged or pledged as security for our revolving credit facility. Substantially all of our Appalachia-Marcellus Shale properties have been pledged as security for PDCM's credit facility. See Note 8, Long-Term Debt, to our consolidated financial statements included elsewhere in this report.

Facilities

We lease 45,015 square feet of office space in Denver, Colorado, which serves as our corporate offices, through December 2015. We own a 32,000 square feet administrative office building located in Bridgeport, West Virginia, where we also lease approximately 18,600 square feet of office space in a second building through October 2014.

We own or lease field operating facilities in Evans, Colorado, Bridgeport, West Virginia and Marietta, Ohio.

Governmental Regulation

While the prices of crude oil and natural gas are market driven, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for crude oil and natural gas production depends on several factors that are beyond our control. These factors include, but are not limited to, regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of crude oil and natural gas available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. In general, state and federal regulations are intended to protect consumers from unfair treatment and oppressive control, reduce environmental and health risks from the development and transportation of crude oil and natural gas, prevent misuse of crude oil and natural gas and protect rights among owners in a common reservoir. Pipelines are subject to the jurisdiction of various federal, state and local agencies. We believe that we are in compliance with such statutes, rules, regulations and governmental orders in all material respects, although there can be no assurance that this is or will remain the case. The following summary discussion on the regulation of the U.S. oil and gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental directives to which our operations may be subject.

Regulation of Crude Oil and Natural Gas Exploration and Production. Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of crude oil and natural gas, the development, production and marketing of crude oil and natural gas and environmental and safety matters. State and local laws and regulations require drilling permits and govern the spacing and density of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, we must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies where the well being drilled is located. Additionally, other regulated matters include:

- bond requirements in order to drill or operate wells;
- well locations;
- drilling and casing methods;
- surface use and restoration of well properties;
- well plugging and abandoning;
- fluid disposal; and
- air emissions.

In addition, our drilling activities involve hydraulic fracturing, which may be subject to additional federal and state disclosure and regulatory requirements discussed in "Environmental Matters" below and in Item 1A, Risk Factors.

Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of lands and leases. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is primarily or exclusively voluntary, it may be more difficult to form units, and therefore, more difficult to drill and develop our leases where we own less than 100% of the leases located within the proposed unit. State laws may establish maximum rates of production from crude oil and natural gas wells, prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. Leases covering state or federal lands often include additional regulations and conditions. The effect of these conservation laws and regulations may limit the amount of crude oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Such laws and regulations may increase the costs of planning, designing, drilling, installing, operating and abandoning our crude oil and natural gas wells and other facilities. These laws and regulations, and any others that are passed by the jurisdictions where we have production, can limit the total number of wells drilled or the allowable production from successful wells, which can limit our reserves. As a result, we are unable to predict the future cost or effect of complying with such regulations.

Regulation of Transportation of Natural Gas. We move natural gas through pipelines owned by other companies and sell natural gas to other companies that also utilize common carrier pipeline facilities. Natural gas pipeline interstate transmission and storage activities are subject to regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act of 1938 ("NGA") and under the Natural Gas Policy Act of 1978, and, as such, rates and charges for the transportation of natural gas in interstate commerce, accounting, and the extension, enlargement or abandonment of jurisdictional facilities, among other things, are subject to regulation. Each natural gas pipeline company holds certificates of public convenience and necessity issued by FERC authorizing ownership and operation of all pipelines, facilities and properties for which certificates are required under the NGA. Each natural gas pipeline company is also subject to the Natural Gas Pipeline Safety Act of 1968, as amended, which regulates safety requirements in the design, construction, operation and maintenance of interstate natural gas transmission facilities. FERC regulations govern how interstate pipelines communicate and do business with their affiliates. Interstate pipelines may not operate their pipeline systems to preferentially benefit their marketing affiliates.

Each interstate natural gas pipeline company establishes its rates primarily through FERC's rate-making process. Key determinants in the ratemaking process are:

- costs of providing service, including depreciation expense;
- allowed rate of return, including the equity component of the capital structure and related income taxes; and
- volume throughput assumptions.

The availability, terms and cost of transportation affect our natural gas sales. Competition among suppliers has greatly increased. Furthermore, gathering is exempt from regulation under the Natural Gas Act, thus allowing gatherers to charge unregulated rates. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen the increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in gas, which could adversely affect cash flows from the affected area.

Additional proposals and proceedings that might affect the industry occur frequently in Congress, FERC, state commissions, state legislatures and the courts. The industry historically has been very heavily regulated; therefore, there is no assurance that the current regulatory approach recently taken by FERC and Congress will continue. We cannot determine to what extent our future operations and earnings will be affected by new legislation, new regulations, or changes in existing regulation, at federal, state or local levels.

Environmental Matters

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public demand for the protection of the environment has increased dramatically in recent years. The trend of more expansive and restrictive environmental legislation and regulations is expected to continue. To the extent laws are enacted or other governmental actions are taken which restrict drilling or impose environmental protection requirements resulting in increased costs, our business and prospects may be adversely affected.

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act ("RCRA") and comparable state statutes. The U.S. Environmental Protection Agency ("EPA") and various state agencies have adopted requirements that limit the approved disposal methods for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore may subject us to more rigorous and costly operating and disposal requirements.

Hydraulic fracturing is commonly used to stimulate production of crude oil and/or natural gas from dense subsurface rock formations. We routinely apply fracturing in our crude oil and natural gas production programs. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the crude oil or natural gas to flow to the wellbore. The process is generally subject to regulation by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over certain fracturing activities involving diesel fuel under the federal Safe Drinking Water Act ("SDWA") and issued draft guidance related to this asserted regulatory authority in February 2014. The guidance explains the EPA’s interpretation of the term “diesel fuel” for permitting purposes, describes existing Underground Injection Control Class II program requirements for permitting underground injection of diesel fuels in hydraulic fracturing and also provides recommendations for EPA permit writers in implementing these requirements. From time to time, Congress has considered legislation that would provide for federal regulation of hydraulic fracturing and disclosure of the chemicals used in the hydraulic fracturing process.

The White House Council on Environmental Quality continues to coordinate an administration-wide review of hydraulic fracturing. The EPA continues its study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with final results expected by December 2014. In addition, the U.S. Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic fracturing completion methods. These ongoing studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. The U.S. Department of the Interior, through the Bureau of Land Management (the “BLM”), is also conducting a rulemaking to require disclosure of chemicals used, mandate well integrity measures and impose other requirements relating to hydraulic fracturing on federal lands.

Certain states in which we operate, including Colorado, Pennsylvania and Ohio, have adopted, and are considering additional regulations that could impose more stringent permitting, transparency and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. For example, Colorado requires that all chemicals used in the hydraulic fracturing of a well be reported in a publicly searchable registry website developed and maintained by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission ("Frac Focus"). The Colorado rules also require operators seeking new location approvals to provide certain information to surface owners and adjacent property owners within 500 feet of a new well. Similarly, Colorado has implemented a baseline groundwater sampling rule and a rule governing setback distances of oil and gas wells located near population centers. In December 2013, the Colorado Oil and Gas Conservation Commission issued new, more restrictive rules regarding spill reporting and remediation. See further discussion in Item 1A, Risk Factors.

In December 2011, West Virginia enacted the Natural Gas Horizontal Well Control Act and amendments to existing laws that together establish a comprehensive, detailed system for permitting and regulation of horizontal natural gas wells. The law applies to most proposed new natural gas wells. The law imposes far more detailed permitting and regulatory requirements than prior law and requires further study and authorizes potential rulemaking by the West Virginia Department of Environmental Protection ("DEP"). Among the new regulatory requirements are: detailed surface owner compensation requirements; performance standards applicable to disposal of drilling cuttings and associated drilling mud; protection of quantity and quality of surface and groundwater systems; advance designation of water withdrawal locations to the DEP and recordkeeping and reporting for all flowback and produced water; and restrictions on well locations.

In November 2013, the Ohio Department of Natural Resources ("ODNR") proposed draft regulations pertaining to well pad construction requirements and increased bonding for construction. The rules are expected to be finalized in 2014.

In Colorado, local governing bodies have begun to issue drilling moratoriums, develop jurisdictional siting, permitting and operating requirements and conduct air quality studies to identify potential public health impacts. For instance, in 2013, the City of Fort Collins, Colorado, adopted a ban on drilling and fracturing of new wells within city limits. In the November 2013 election, voters in the cities of Boulder, Lafayette, Fort Collins and Brighton passed hydraulic fracturing bans. We do not currently have operations in any of these areas. In addition, as discussed in more detail in Item 1A. Risk Factors, a ballot initiative has been proposed in Colorado which, if approved and upheld, could greatly expand the right of local governments to limit or prohibit oil and natural gas production and development in their jurisdictions. If new laws or regulations that significantly restrict hydraulic fracturing or well locations continue to be adopted at local levels or are adopted at the state level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. If hydraulic fracturing becomes regulated as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and permitting delays, as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of crude oil and natural gas that we are ultimately able to produce from our reserves. We continue to be active in stakeholder and interest groups and to engage with regulatory agencies in an open, proactive dialogue.

We currently own or lease numerous properties that for many years have been used for the exploration and production of crude oil and natural gas. Although we believe that we have utilized good operating and waste disposal practices, and when necessary, appropriate remediation techniques, prior owners and operators of these properties may not have utilized similar practices and techniques and hydrocarbons or other wastes may have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), RCRA and analogous state laws, as well as state laws governing the management of crude oil and natural gas wastes. Under such laws, we may be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or remediate property contamination (including surface and groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain 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 or sites 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 or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. As an owner and operator of crude oil and natural gas wells, we may be liable pursuant to CERCLA and similar state laws.

Our operations are subject to the federal Clean Air Act ("CAA") and comparable state and local requirements. The CAA contains provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states continue the development of regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. Greenhouse gas record keeping and reporting requirements of the CAA became effective in 2011 and will continue into the future with increased costs for administration and implementation of controls. Federal New Source Performance Standards regarding oil and gas operations ("NSPS OOOO") became effective in 2012 and 2013, with additional NSPS provisions expected in 2014, all of which will add administrative and operational costs. Colorado continues to draft and adopt new regulations to meet the requirements of NSPS OOOO and will promulgate significant rules relating specifically to crude oil and natural gas operations that are more stringent than NSPS OOOO and are expected to be finalized by March 2014.

The federal Clean Water Act ("CWA") and analogous state laws impose strict controls against the discharge of pollutants and fill material, including spills and leaks of crude oil and other substances. The CWA also requires approval and/or permits prior to construction, where construction will disturb wetlands or other waters of the U.S. The CWA also regulates storm water run-off from crude oil and natural gas facilities and requires storm water discharge permits for certain activities. Spill Prevention, Control, and Countermeasure ("SPCC") requirements of the CWA require appropriate secondary containment loadout controls, piping controls, berms and other measures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon spill, rupture or leak. The EPA and U.S. Army Corps of Engineers released a Connectivity Report in September 2013, which determined that all tributary streams, wetlands, open water in floodplains and riparian areas are connected. This report supported the drafting of new rules regarding what will be considered waters of the U.S. The new rules were submitted for inter-agency review in October 2013 and are expected to be available for public review by May 2014.

Crude oil production is subject to many of the same operating hazards and environmental concerns as natural gas production, but is also subject to the risk of crude oil spills. Federal regulations require certain owners or operators of facilities that store or otherwise handle crude oil, including us, to procure and implement additional SPCC measures relating to the possible discharge of crude oil into surface waters. The Oil Pollution Act of 1990 ("OPA") subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from crude oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. Historically, we have not experienced any significant crude oil discharge or crude oil spill problems. Our shift in production since mid-2010 to a greater percentage of crude oil increases our risks related to soil and water contamination.

Our costs relating to protecting the environment have risen over the past few years and are expected to continue to rise in 2014 and beyond. Environmental regulations have increased our costs and planning time, but have had no materially adverse effect on our ability to operate to date. However, no assurance can be given that environmental regulations or interpretations of such regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on our business, financial condition or results of operations. See Note 11, Commitments and Contingencies, to our consolidated financial statements included elsewhere in this report.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including, but not limited to, the risk of fire, explosions, blowouts, cratering, pipe failure, casing collapse, abnormally pressured formations and environmental hazards such as gas leaks, ruptures and discharges of crude oil and natural gas. The occurrence of any of these events could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our pipeline, gathering and distribution operations are subject to the many hazards inherent in the industry. These hazards include damage to wells, pipelines and other related equipment, damage to property caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations. In September 2013, we experienced widespread flooding in our Wattenberg Field operations in Weld County, Colorado, which resulted in a shut-in of approximately 200 vertical wells, approximately 40 of which remained shut-in at December 31, 2013. We have incurred significant costs to replace damaged well equipment and to bring vertical wells back on-line. Assessment of the full economic impact of the flooding is on going.

Any significant problems related to our facilities could adversely affect our ability to conduct our operations. In accordance with customary industry practice, we maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event not fully insured against could materially adversely affect our operations and financial condition. We cannot predict whether insurance will continue to be available at premium levels that justify our purchase or will be available at all. Furthermore, we are not insured against our economic losses resulting from damage or destruction to third-party property, such as transportation pipelines, crude oil refineries or natural gas processing facilities. Such an event could result in significantly lower regional prices or our inability to deliver our production.

Competition and Technological Changes

We believe that our exploration, drilling and production capabilities and the experience of our management and professional staff generally enable us to compete effectively. We encounter competition from numerous other crude oil and natural gas companies, drilling and income programs and partnerships in all areas of operations, including drilling and marketing crude oil and natural gas and obtaining desirable crude oil and natural gas leases on producing properties. Many of these competitors possess larger staffs and greater financial resources than we do, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. Our ability to explore for crude oil and natural gas prospects and to acquire additional properties in the future depends upon our ability to conduct our operations, evaluate and select suitable properties and consummate transactions in this highly competitive environment. We also face intense competition in the marketing of natural gas from competitors including other producers and marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic crude oil and natural gas exploration. Furthermore, competition among companies for favorable prospects can be expected to continue and it is anticipated that the cost of acquiring properties will increase in the future.

Recently, certain regions experienced strong demand for drilling services and supplies, which resulted in increasing costs. The Wattenberg Field, Utica Shale and Appalachia-Marcellus Shale have experienced intense competition for drilling and pumping services. Factors affecting competition in the industry include price, location of drilling, availability of drilling prospects and drilling rigs, fracturing services, pipeline capacity, quality of production and volumes produced. We believe that we can compete effectively in the industry in each of the areas where we have operations. Nevertheless, our business, financial condition and results of operations could be materially adversely affected by competition. We also compete with other crude oil and natural gas companies, as well as companies in other industries, for the capital we need to conduct our operations. Should economic conditions deteriorate and financing become more expensive and difficult to obtain, we may not have adequate capital to execute our business plan and we may be forced to curtail our drilling and acquisition activities.

The oil and gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition, results of operations and cash flows could be materially adversely affected.

Employees

As of December 31, 2013, we had 412 employees. Our employees are not covered by collective bargaining agreements. We consider relations with our employees to be good.

WHERE YOU CAN FIND ADDITIONAL INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. Our SEC filings are available free of charge from the SEC’s website at www.sec.gov or from our website at www.pdce.com. You may also read or copy any document we file at the SEC’s public reference room in Washington, D.C., located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the public reference room. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact PDC Energy Inc., Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call (800) 624-3821.

We recommend that you view our website for additional information, as we routinely post information that we believe is important for investors. Our website can be used to access such information as our recent news releases, committee charters, code of business conduct and ethics, shareholder communication policy, director nomination procedures and our whistle blower hotline. While we recommend that you view our website, the information available on our website is not part of this report and is not incorporated by reference.

ITEM 1A. RISK FACTORS

You should carefully consider the following risk factors in addition to the other information included in this report. Each of these risk factors could adversely affect our business, operating results and financial condition, as well as adversely affect the value of an investment in our common stock or other securities.

Crude oil, natural gas and NGL prices fluctuate and a decline in these prices can significantly affect the value of our assets and our financial results and impede our growth.

Our revenue, profitability, cash flows and liquidity depend in large part upon the price we receive for our crude oil, natural gas and NGLs. In addition, changes in commodity prices have a significant effect on the value and quantity of our reserves, which can in turn affect the borrowing base under our revolving credit facility and our access to other sources of capital, and on the nature and scale of our operations. The markets for crude oil, natural gas and NGLs are often volatile, and prices may fluctuate in response to relatively minor changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control, including national and international economic and political factors and federal and state legislation. For example, geopolitical events in the Middle East or elsewhere could affect global crude oil prices, and continued weakness in the overall economic environment could adversely affect all commodity prices.

In addition to factors affecting the price of crude oil, natural gas and NGLs generally, the prices we receive for our production are affected by factors specific to us and to the local markets where the production occurs. The prices that we receive for our production are generally lower than the relevant benchmark prices that are used for calculating commodity derivative positions. These differences, or differentials, are difficult to predict and may widen in the future. Differentials can be influenced by, among other things, local or regional supply and demand factors and the terms of our sales contracts. Differentials on oil produced in the Wattenberg Field have widened in recent months, in part as a result of the midstream capacity issues discussed below. Over the longer term, differentials will be significantly affected by factors such as investment decisions made by providers of midstream facilities and services, refineries and other industry participants, and the overall regulatory and economic climate. For example, increases in U.S. domestic oil production generally may result in widening differentials, particularly for production from some basins. We may be materially and adversely impacted by widening differentials on our production.

The marketability of our production is dependent upon transportation and processing facilities the capacity and operation of which we do not control. Market conditions or operational impediments, including high line pressures, particularly in the Wattenberg Field, and other impediments affecting midstream facilities and services, could hinder our access to crude oil, natural gas and NGL markets, increase our costs or delay production and thereby adversely affect our profitability.

Our ability to market our production depends in substantial part on the availability, proximity and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. If adequate midstream facilities and services are not available to us on a timely basis and at acceptable costs, our production and results of operations will be adversely affected. These risks are greater for us than for some of our competitors because our operations are focused on areas where there is currently a substantial amount of development activity, which increases the likelihood that there will be periods of time in which there is insufficient midstream capacity to accommodate the resulting increases in production. For example, due to increased drilling activities by us and third parties, and hot temperatures during the summer months, the principal third-party provider we use in the Wattenberg area for midstream facilities and services has recently experienced high gathering system line pressure. The resulting capacity constraints impacted the productivity of some of our older wells and limited the incremental production impact of our newer horizontal wells. This constrained our production and reduced our revenue from the affected wells. Capacity constraints affecting natural gas production also impact our ability to produce the associated NGLs. We are also dependent on the availability and capacity of purchasers for our production. For example, recent reductions in purchases by a local crude oil refinery have increased the amount of oil that we have to transport out of the Wattenberg area for sale. This has increased our transportation costs and reduced the price we receive for the affected production. We expect this situation to continue for the foreseeable future. In addition, the use of alternative forms of transportation such as trucks or rail involve risks as well. For example, recent and well-publicized accidents involving trains delivering crude oil could result in increased levels of regulation and transportation costs. We face similar risks in other areas, including our Utica operating area, as gathering/processing infrastructure is currently in the development phase and development activity conducted by us and others is increasing. We are also dependent on third party pipeline infrastructure to deliver our natural gas production to market in the Appalachia-Marcellus area. In addition to causing production curtailments, capacity constraints can also reduce the price we receive for the crude oil, natural gas and NGLs we produce.

Federal, state and local legislation and regulations relating to hydraulic fracturing could result in increased costs, additional drilling and operating restrictions or delays in the production of crude oil, natural gas and NGLs, and could prohibit hydraulic fracturing activities.

Most of our drilling uses hydraulic fracturing. Hydraulic fracturing is an important and commonly used process in the completion of unconventional wells in shale, coalbed, and tight sand formations. Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used by the crude oil and natural gas industry in fracturing fluids under the Safe Drinking Water Act ("SDWA"), and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, the Emergency Planning and Community Right-to-Know Act ("EPCRA"), or other laws. Sponsors of these bills, which have been subject to various proceedings in the legislative process, including in the House Energy and Commerce Committee and the Senate Environmental and Public Works Committee, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. In March 2011, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. EPA issued an initial report about the study in December 2012. The initial report described the focus of the continuing study but did not include any data concerning EPA's efforts to date, nor did it draw any conclusions about the safety of hydraulic fracturing. A draft report including data and conclusions is expected in 2014.

EPA has begun a Toxic Substances Control Act ("TSCA") rulemaking which will collect expansive information on the chemicals used in hydraulic fracturing fluid, as well as other health-related data, from chemical manufacturers and processors. EPA has not indicated when it intends to issue a proposed rule. Concurrently, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices.

EPA also finalized major new CAA standards (New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants) applicable to hydraulically fractured natural gas wells and certain storage vessels in August 2012. The standards will require, among other things, use of reduced emission completions, or green completions, to reduce volatile organic compound emissions during well completions as well as new controls applicable to a wide variety of storage tanks and other equipment, including compressors, controllers, and dehydrators. While most key provisions in the new CAA standards are not effective until 2015 and EPA currently is re-considering parts of the rule, the rules associated with such standards are substantial and will increase future costs of our operations and will require us to make modifications to our operations and install new equipment.

EPA has also issued permitting guidance under the SDWA for the underground injection of liquids from hydraulically fractured (and other) wells where diesel is used. This recently-issued guidance may create duplicative requirements, further slow down the permitting process in certain areas, increase the costs of operations, and result in expanded regulation of hydraulic fracturing activities by EPA depending on how it is implemented. Certain other federal agencies are analyzing, or have been requested to review, environmental issues associated with hydraulic fracturing. Most notably, the U.S. Department of the Interior, through the BLM, is currently conducting a rulemaking that will require, among other things, disclosure of chemicals and more stringent well integrity measures associated with hydraulic fracturing operations on public land. BLM has not indicated when it will issue a final rule.

In addition, the governments of certain states, including Colorado, Pennsylvania, Ohio, and West Virginia, have adopted or are considering adopting laws and regulations that impose or could impose, among other requirements, stringent permitting or air emission control requirements, disclosure, wastewater disposal, baseline sampling, well construction and well location requirements on hydraulic fracturing operations or otherwise seek to ban underground injection of fracturing wastewater or fracturing activities altogether. For example, in January 2012, the ODNR issued a temporary moratorium on the development of hydraulic fracturing disposal wells in northeast Ohio in order to study the relationship between these wells and minor earthquakes reported in the area. As a result, ODNR promulgated new and more stringent regulations for certain underground injection wells, including requirements for a complete suite of geophysical logs, analytical interpretation of the logs, and enhanced monitoring and recording.

At the local level, some municipalities and local governments have adopted or are considering bans on hydraulic fracturing. Voters in the cities of Fort Collins, Boulder, and Lafayette, Colorado recently approved bans of varying length on hydraulic fracturing within their respective city limits.

In addition, lawsuits have been filed against unrelated third parties in Pennsylvania, New York, Arkansas, Colorado, Ohio, West Virginia, and several other states alleging contamination of drinking water by hydraulic fracturing.

Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition to crude oil, natural gas and NGL production activities using hydraulic fracturing techniques. Additional legislation, regulation, litigation, or moratoria could also lead to operational delays or lead us to incur increased operating costs in the production of crude oil, natural gas and NGLs, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing or other drilling activities. If these legislative, regulatory, litigation, and other initiatives cause a material decrease in the drilling of new wells or an increase in drilling costs, our profitability could be materially impacted.

A ballot initiative has been proposed in Colorado which, if approved, could vastly expand the right of local governments to limit or prohibit oil and natural gas production and development in their jurisdictions. Should this or any similar initiative or legislation be successful and survive legal challenge, additional limitations or prohibitions could be placed on crude oil and natural gas production and development within certain areas of Colorado or the state as a whole. This could adversely affect the cost, manner, and feasibility of development activities in Colorado, particularly those involving hydraulic fracturing, and significantly affect the value of our assets and our financial results and impede our growth.

Certain interest groups in Colorado opposed to oil and natural gas development generally, and hydraulic fracturing in particular, have advanced various options for ballot initiatives aimed at significantly limiting or preventing oil and natural gas development. To date, one initiative has been formally proposed. Colorado Community Rights Network has submitted to the Colorado Legislative Council a proposed amendment to the Colorado Constitution that would add a new section to the Bill of Rights regarding the right of local governments to self-govern. This constitutional amendment, should it be successfully implemented and survive legal challenge, would grant local governments in Colorado the right, without limitation, to prohibit crude oil and natural gas development within their respective jurisdictions and would clarify that such prohibitions would not be preempted by conflicting international, federal, or state laws. Other ballot initiatives and legislation focused on allowing localities greater latitude to regulate oil and natural gas development in Colorado are under discussion. Additional ballot initiatives and legislation directly impacting oil and natural gas development, including through further regulation of hydraulic fracturing, are also possible. Should any of these initiatives be successful and survive legal challenge, they could have a materially adverse impact on our ability to drill and/or produce crude oil and natural gas in certain areas in Colorado, or the state generally, and could materially impact our results of operations, production and reserves.

Environmental and overall public scrutiny focused on the oil and gas industry is increasing. The current trend is to increase regulation of our operations and the industry. We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production, and marketing operations are regulated extensively at the federal, state, and local levels. Environmental and other governmental laws and regulations have increased the costs of planning, designing, drilling, installing, operating, and abandoning crude oil and natural gas wells and associated facilities. Under these laws and regulations, we could also be liable for personal injuries, property damage, and natural resource or other damages. Similar to our competitors, we incur substantial operating and capital costs to comply with such laws and regulations. These compliance costs may put us at a competitive disadvantage compared to larger companies in the industry which can more easily capture economies of scale with respect to compliance. Failure to comply with these laws and regulations may result in the suspension or termination of our operations or other operational impediments and subject us to administrative, civil, and criminal penalties. Moreover, public interest in environmental protection has increased in recent years-particularly with respect to hydraulic fracturing-and environmental organizations have opposed, with some success, certain drilling projects.

In addition, our activities are subject to regulations governing conservation practices, protection of wildlife and habitat, and protection of correlative rights by state governments. These regulations affect our operations, increase our costs of exploration and production, and limit the quantity of crude oil, natural gas and NGLs that we can produce and market. A major risk inherent in our drilling plans is the possibility that we will be unable to obtain needed drilling permits from relevant governmental authorities in a timely manner. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions or costs could have a material adverse effect on our ability to explore or develop our properties.

Additionally, the crude oil and natural gas regulatory environment could change in ways that substantially increase our financial and managerial compliance costs, increase our exposure to potential damages or limit our activities. At the state level, for instance, the Colorado Oil and Gas Conservation Commission (“COGCC”) issued a rule in 2013 governing mandatory minimum spacing, or setbacks, between oil and gas wells and occupied buildings and other areas. Similarly, the COGCC has discussed measures to focus on wellbore integrity. Also in 2013, the COGCC issued rules that require baseline sampling of certain ground and surface water in most areas of Colorado and impose stringent spill reporting and remediation requirements. These new sampling requirements could increase the costs of developing wells in certain locations. In addition to increasing costs of operation, these rules could prevent us from drilling wells on certain locations we plan to develop, thereby reducing our reserves as well as our future revenues.

In addition, in November 2013, the Colorado Department of Public Health and Environment’s Air Quality Control Commission (“AQCC”) approved proposed regulations that would impose stringent new requirements relating to air emissions from oil and gas facilities in Colorado. These new rules, which are expected to be finalized in spring 2014, will require new controls, and impose additional monitoring, recordkeeping, and reporting requirements for most operators in Colorado. As part of the proposed rule package, the AQCC approved the direct regulation of hydrocarbon (i.e., methane) emissions from the Colorado oil and gas sector. If finalized as proposed, such direct state-only regulation of methane (a greenhouse gas) from a single industry sector in the absence of comparable federal regulation is a significant new authority being asserted at the state level and has the potential to adversely affect operations in Colorado as well as in other parts of the country. Along the same lines, local governments are undertaking air quality studies to assess potential public health impacts from oil and gas operations. These studies, in combination with other air quality-related studies that are national in scope, may result in the imposition of additional regulatory requirements on oil and gas operations.

Other potential laws and regulations affecting us include new or increased severance taxes proposed in several states, including Pennsylvania and Ohio. This could adversely affect our existing operations in these states and the economic viability of future drilling. Additional laws, regulations, or other changes could significantly reduce our future growth, increase our costs of operations, and reduce our cash flows, in addition to undermining the demand for the crude oil, natural gas and NGLs we produce.

Our ability to produce crude oil and natural gas could be impaired if we are unable to acquire adequate supplies of water for our drilling and completion operations or are unable to dispose of the water we use at a reasonable cost and within applicable environmental rules.

Our operations could be adversely impacted if we are unable to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations. Currently, the quantity of water required in certain completion operations, such as hydraulic fracturing, and changing regulations governing usage may lead to water constraints and supply concerns (particularly in some parts of the country). In addition, notwithstanding recent flooding in Colorado discussed below, Colorado and other western states have recently experienced drought conditions. As a result, future availability of water from certain sources used in the past may become limited.

The imposition of new environmental initiatives relating to wastewater could restrict our ability to conduct certain operations such as hydraulic fracturing. This includes potential restrictions on waste disposal, including, but not limited to, produced water, drilling fluids, and other wastes associated with the exploration, development, or production of crude oil and natural gas. For example, in 2010 a petition was filed by the Natural Resources Defense Council with EPA requesting that the agency reassess its prior and long-standing determination that certain oil and natural gas exploration and production wastes would not be regulated as hazardous waste under Subtitle C of the RCRA. EPA has not yet acted on the petition and it remains pending. Were EPA to begin treating some or all of these wastes as "hazardous" under Subtitle C in response to the petition, the consequences for our operations would be serious, and would include a significant increase in costs associated with waste treatment and disposal and a potential inability to conduct operations in some instances.

The CWA and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas waste, into navigable waters or other regulated federal and state waters. Permits or other approvals must be obtained to discharge fill and pollutants into regulated waters and to conduct construction activities in such waters and wetlands. Uncertainty regarding regulatory jurisdiction over wetlands and other regulated waters of the United States has complicated, and will continue to complicate and increase the cost of, obtaining such permits or other approvals. Most recently, EPA and the U.S. Army Corps of Engineers submitted to the White House Office of Management and Budget for review a proposed rule on defining jurisdictional waters of the United States. An expansive definition of such jurisdictional waters could affect our ability to operate in certain areas, increase costs of operations, and cause significant scrutiny and delays in permitting. While generally exempt under federal programs, many state agencies have also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. These permits, in turn, impose far-ranging monitoring, flow control, and other obligations that have generated, and will continue to generate, increased costs for our operations.

In October 2011, EPA announced its intention to develop federal pretreatment standards for wastewater discharges associated with hydraulic fracturing activities. If adopted, the pretreatment rules will require shale gas operations to pretreat wastewater before transfer to treatment facilities. Proposed rules are expected in 2014. Some states, including Pennsylvania, have banned the treatment of fracturing wastewater at publicly owned treatment facilities. There has been recent nationwide concern, particularly in Ohio, over earthquakes associated with Class II underground injection control wells, a predominant storage method for crude oil and gas wastewater. As seen in Ohio, it is likely that new rules and regulations will be developed to address these concerns, possibly eliminating access to Class II wells in certain locations, and increasing the cost of disposal in others.

Finally, the EPA study noted above has focused and will continue to focus on various stages of water use in hydraulic fracturing operations. It is possible that, following the conclusion of EPA's study, the agency will move to more strictly regulate the use of water in hydraulic fracturing operations. While we cannot predict the impact that these changes may have on our business at this time, they may be material to our business, financial condition, and operations. In addition, an inability to meet our water supply needs to conduct our completion operations may adversely impact our business. These potential water-related concerns may be heightened by recent flooding events in Colorado. For example, we experienced damage to some of our facilities as well as other operational impediments caused by the flooding event. Future legal and regulatory changes related to this event could negatively affect our financial condition and operations.

A substantial part of our crude oil, natural gas and NGLs production is located in the Wattenberg Field, making us vulnerable to risks associated with operating primarily in a single geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing formations.

Our operations are focused primarily on the Wattenberg Field, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Because our operations are not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of crude oil, natural gas and NGLs produced from the wells in the area, natural disasters such as the flooding that occurred in the area in September 2013, restrictive governmental regulations, transportation capacity constraints, curtailment of production or interruption of transportation, and any resulting delays or interruptions of production from existing or planned new wells. For example, the recent increase in activity in the Wattenberg Field has contributed to bottlenecks in processing and transportation that have negatively affected our results of operations, and these adverse effects may be disproportionately severe to us compared to our more geographically diverse competitors. Similarly, the concentration of our assets within a small number of producing formations exposes us to risks, such as changes in field-wide rules, that could adversely affect development activities or production relating to those formations. Such an event could have a material adverse effect on our results of operations and financial condition.

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

Calculating reserves for crude oil, natural gas and NGLs requires subjective estimates of remaining volumes of underground accumulations of hydrocarbons. Assumptions are also made concerning commodity prices, production levels, and operating and development costs over the economic life of the properties. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may be inaccurate. Independent petroleum engineers prepare our estimates of crude oil, natural gas and NGLs reserves using pricing, production, cost, tax and other information that we provide. The reserve estimates are based on certain assumptions regarding commodity prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual results could greatly affect:

- the economically recoverable quantities of crude oil, natural gas and NGLs attributable to any particular group of properties;
- future depreciation, depletion and amortization ("DD&A") rates and amounts;
- impairments in the value of our assets;
- the classifications of reserves based on risk of recovery;
- estimates of future net cash flows;
- timing of our capital expenditures; and
- the amount of funds available for us to utilize under our revolving credit facility.

Some of our reserve estimates must be made with limited production histories, which renders these reserve estimates less reliable than estimates based on longer production histories. Horizontal drilling in the Wattenberg Field is a relatively recent development, whereas vertical drilling has been used by producers in this field for over 40 years. As a result, the amount of production data from horizontal wells available to reserve engineers is relatively small, and future reserve estimates will be affected by additional production data as it becomes available. Horizontal drilling in the Utica Shale has an even more limited history, particularly in the southern part of the play where most of our acreage is located. Further, reserve estimates are based on the volumes of crude oil, natural gas and NGLs that are anticipated to be economically recoverable from a given date forward based on economic conditions that exist at that date. The actual quantities of crude oil, natural gas and NGLs recovered will be different than the reserve estimates since they will not be produced under the same economic conditions as used for the reserve calculations. In addition, quantities of probable and possible reserves by definition are inherently more risky than proved reserves and are less likely to be recovered.

At December 31, 2013, approximately 72% of our estimated proved reserves (by volume) were undeveloped. These reserve estimates reflected our plans to make significant capital expenditures to convert our PUDs into proved developed reserves, including approximately $2.5 billion during the five years ending December 31, 2018. You should be aware that the estimated development costs may not be accurate, development may not occur as scheduled and results may not be as estimated. If we choose not to develop PUDs, or if we are not otherwise able to successfully develop them, we will be required to remove the associated volumes from our reported proved reserves. In addition, under the SEC’s reserve reporting rules, because PUDs generally may be booked only if they relate to wells scheduled to be drilled within five years of the date of booking, we may be required to downgrade any PUDs that are not developed within this five-year time frame to probable or possible.

The present value of the estimated future net cash flows from our proved reserves is not necessarily the same as the current market value of those reserves. Pursuant to SEC rules, the estimated discounted future net cash flows from our proved reserves, and the estimated quantity of those reserves, were based on the prior 12-month average crude oil and natural gas index prices. However, factors such as actual prices we receive for crude oil and natural gas and hedging instruments, the amount and timing of actual production, amount and timing of future development costs, supply of and demand for crude oil, natural gas and NGLs and changes in governmental regulations or taxation, also affect our actual future net cash flows from our properties. If we had used current forward strip commodity prices instead of the 12-month average prices mandated by SEC rules, the estimated quantities of our proved reserves and cash flows from those reserves as of December 31, 2013 would have been lower.

The timing of both our production and incurrence of expenses in connection with the development and production of crude oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% discount factor (the rate required by the SEC) we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates currently in effect and risks associated with our properties or the industry in general.

Unless reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations. We may not be able to develop our identified drilling locations as planned.

Producing crude oil, natural gas and NGL reservoirs are generally characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline may change over time and may exceed our estimates. Our future reserves and production and, therefore, our cash flows and income, are highly dependent on our ability to efficiently develop and exploit our current reserves and to economically find or acquire additional recoverable reserves. We may not be able to develop, discover or acquire additional reserves to replace our current and future production at acceptable costs. Our failure to do so would adversely affect our future operations, financial condition and results of operations.

We have identified a number of well locations as an estimation of our future multi-year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including crude oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, midstream constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce crude oil, natural gas or NGLs from these or any other potential well locations. In addition, the number of drilling locations available to us will depend in part on the spacing of wells in our operating areas. An increase in well density in an area could result in additional locations in that area, but a reduced production performance from the area on a per-well basis. Further, certain of the horizontal wells we intend to drill in the future may require pooling of our lease interests with the interests of third parties. If these third parties are unwilling to pool their interests with ours, and we are unable to require such pooling on a timely basis or at all, this may limit the total locations we can drill. As such, our actual drilling activities may materially differ from those presently identified. Further, our inventory of drilling projects includes locations in addition to those that we currently classify as 3P. The development of and results from these additional projects are more uncertain than those relating to 3P locations, and significantly more uncertain than those relating to proved locations.

The wells we drill may not yield crude oil, natural gas or NGLs in commercially viable quantities, and productive wells may be less successful than we expect.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of hydrocarbon-bearing rocks. However, our geologists cannot know conclusively prior to drilling and testing whether crude oil, natural gas or NGLs will be present in sufficient quantities to repay drilling or completion costs and generate a profit given the available data and technology. If a well is determined to be dry or uneconomic, which can occur even though it contains some crude oil, natural gas or NGLs, it is classified as a dry hole and must be plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point, the cost of plugging, and lease costs associated with the prospect. Even wells that are completed and placed into production may not produce sufficient crude oil, natural gas and NGLs to be profitable, or they may be less productive and/or profitable than we expected. If we drill a dry hole or unprofitable well on a current or future prospect, the profitability of our operations will decline and the value of our properties will likely be reduced. These risks are greater in developing areas such as the Utica

Shale, where we are currently investing substantial capital. Exploratory drilling is typically subject to substantially greater risk than development drilling. In addition, initial results from a well are not necessarily indicative of its performance over a longer period.

Drilling for and producing crude oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations.

Drilling activities are subject to many risks, including the risk that we will not discover commercially productive reservoirs. Drilling for crude oil and natural gas can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations as a result of other factors, including:

- unusual or unexpected geological formations;
- pressures;
- fires;
- floods;
- loss of well control;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delays in the delivery of equipment and services;
- unanticipated environmental liabilities;
- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and regulatory penalties. For example, a loss of containment of hydrocarbons during drilling activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including for environmental remediation, depending upon the circumstances of the loss of containment, the nature and scope of the loss and the applicable laws and regulations. We maintain insurance against various losses and liabilities arising from operations; however, insurance against certain operational risks may not be available or may be prohibitively expensive relative to the perceived risks presented. For example, we may not have coverage with respect to a pollution event if we are unaware of the event while it is occurring and are therefore unable to report the occurrence of the event to our insurance company within the time frame required under our insurance policy. Thus, losses could occur for uninsurable or uninsured risks or for amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance and/or governmental or third party responses to an event could have a material adverse effect on our business activities, financial condition and results of operations. We are currently involved in various remedial and investigatory activities at some of our wells and related sites.

Our business strategy focuses on production in our liquid-rich and high impact shale plays. In this regard, we plan to allocate our capital to an active horizontal drilling program. Historically, most of the wells we drilled were vertical wells. Since 2012, however, we have devoted the majority of our capital budget to drilling horizontal wells. Drilling horizontal wells is technologically more difficult than drilling vertical wells - including as a result of risks relating to our ability to fracture stimulate the planned number of stages and to successfully run casing the length of the well bore - and the risk of failure is therefore greater than the risk involved in drilling vertical wells. Additionally, drilling a horizontal well is typically far costlier than drilling a vertical well. This means that the risks of our drilling program will be spread over a smaller number of wells, and that, in order to be economic, each horizontal well will need to produce at a higher level in order to cover the higher drilling costs. In addition, we have transitioned to the use of multi-well pads instead of single-well sites. The use of multi-well pad drilling increases some operational risks because problems affecting the pad or a single well could adversely affect production from all of the wells on the pad. Pad drilling can also make our overall production, and therefore our revenue and cash flows, more volatile, because production from multiple wells on a pad will typically commence simultaneously. While we believe that we will be better served by drilling horizontal wells using multi-well pads, the risk component involved in such drilling will be increased in some respects, with the result that we might find it more difficult to achieve economic success in our drilling program.

Under the “successful efforts” accounting method that we use, unsuccessful exploratory wells must be expensed in the period when they are determined to be non-productive, which reduces our net income in such periods and could have a negative effect on our profitability.

We conduct exploratory drilling in order to identify additional opportunities for future development. Under the “successful efforts” method of accounting that we use, the cost of unsuccessful exploratory wells must be charged to expense in the period in which the wells are determined to be unsuccessful. In addition, lease costs for acreage condemned by the unsuccessful well must also be expensed. In contrast, unsuccessful development wells are capitalized as a part of the investment in the field where they are located. Because exploratory wells generally are more likely to be unsuccessful than development wells, we anticipate that some or all of our exploratory wells may not be productive. The costs of such unsuccessful exploratory wells could result in a significant reduction in our profitability in periods when the costs are required to be expensed and could have a negative effect on our ability to comply with our debt covenants.

Increasing finding and development costs may impair our profitability.

In order to continue to grow and maintain our profitability, we must add new reserves that exceed our production over time at a finding and development cost that yields an acceptable operating margin and DD&A rate. Without cost effective exploration, development or acquisition activities, our production, reserves and profitability will decline over time. Given the relative maturity of most crude oil and natural gas basins in North America and the high level of activity in the industry, the cost of finding new reserves through exploration and development operations has been increasing in some basins. The acquisition market for properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values for crude oil properties have climbed in recent years and may continue to increase in the future. This increase in finding and development costs results in higher DD&A rates. If the upward trend in crude oil finding and development costs continues, we will be exposed to an increased likelihood of a write-down in the carrying value of our crude oil properties in response to any future decrease in commodity prices and/or reduction in the profitability of our operations.

Depressed natural gas prices could result in significant impairment charges and significant downward revisions of proved natural gas reserves.

The domestic natural gas market remains weak. Low natural gas prices could result in, among other adverse effects, significant impairment charges in the future. The cash flow model we use to assess properties for impairment includes numerous assumptions, such as management's estimates of future oil and gas production and commodity prices, market outlook on forward commodity prices and operating and development costs. All inputs to the cash flow model must be evaluated at each date that the estimate of future cash flows for each producing basin is calculated. However, a significant decrease in long-term forward natural gas prices alone could result in a significant impairment for our properties that are sensitive to declines in natural gas prices. In December 2012, we recognized an impairment charge of $161.2 million associated with our Piceance Basin proved crude oil and natural gas properties. In 2013, we recognized additional charges of $48.8 million associated with our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin producing properties. Similar charges could occur in the future. In addition, low natural gas prices could result in significant downward revisions to our proved natural gas reserves. Future declines in crude oil prices could have similar effects.

Our development and exploration operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our production and reserves, and ultimately our profitability.

Our industry is capital intensive. We expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of crude oil, natural gas and NGL reserves. To date, we have financed capital expenditures primarily with bank borrowings under our revolving credit facility, cash generated by operations and proceeds from capital markets transactions and the sale of properties. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

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

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower commodity prices, operating difficulties or for any other reason, our need for capital from other sources would increase, and there can be no assurance that such other sources of capital would be available at that time on reasonable terms or at all. If we raise funds by issuing additional equity securities, this would have a dilutive effect on existing shareholders. If we raise funds through the incurrence of debt, the risks we face with respect to our indebtedness would increase and we would incur additional interest expense. Our inability to obtain sufficient financing on acceptable terms would adversely affect our financial condition and profitability.

We have a substantial amount of debt and the cost of servicing, and risks related to refinancing, that debt could adversely affect our business. Those risks could increase if we incur more debt.

We have a substantial amount of indebtedness. As a result, a significant portion of our cash flows will be required to pay interest and principal on our indebtedness, and we may not generate sufficient cash flows from operations, or have future borrowing capacity available, to enable us to repay our indebtedness or to fund other liquidity needs.

Servicing our indebtedness and satisfying our other obligations will require a significant amount of cash. Our cash flows from operating activities and other sources may not be sufficient to fund our liquidity needs. Our ability to pay interest and principal on our indebtedness and to satisfy our other obligations will depend on our future operating performance and financial condition and the availability of refinancing indebtedness, which will be affected by prevailing economic conditions and financial, business and other factors, many of which are beyond our control.

A substantial decrease in our operating cash flows or an increase in our expenses could make it difficult for us to meet our debt service requirements and could require us to modify our operations, including by curtailing our exploration and drilling programs, selling assets, refinancing all or a portion of our existing debt or obtaining additional financing. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations. Our ability to restructure or refinance our debt will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our debt could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. In addition, the terms of future debt agreements may, and our existing debt agreements do, restrict us from implementing some of these alternatives. In the absence of adequate cash from operations and other available capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. We may not be able to consummate these dispositions for fair market value, in a timely manner or at all. Furthermore, any proceeds that we could realize from any dispositions may not be adequate to meet our debt service or other obligations then due. Because the cash required to service our indebtedness is not available to finance our operations and other business activities, our indebtedness limits our flexibility in planning for or reacting to changes in our business and the industry in which we operate and increases our vulnerability to economic downturns and sustained declines in commodity prices.

Covenants in our debt agreements currently impose, and future financing agreements may impose, significant operating and financial restrictions.

The indenture governing our senior notes and our revolving credit facility contain restrictions, and future financing agreements may contain additional restrictions, on our activities, including covenants that restrict our and certain of our subsidiaries' ability to:

- incur additional debt;
- pay dividends on, redeem or repurchase stock;
- create liens;
- make specified types of investments;
- apply net proceeds from certain asset sales;
- engage in transactions with our affiliates;
- engage in sale and leaseback transactions;
- merge or consolidate;
- restrict dividends or other payments from restricted subsidiaries;
- sell equity interests of restricted subsidiaries; and
- sell, assign, transfer, lease, convey or dispose of assets.

Our revolving credit facility is secured by all of our crude oil and natural gas properties as well as a pledge of all ownership interests in our operating subsidiaries. The restrictions contained in our debt agreements may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We may also incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. Similar issues may arise with respect to PDCM's debt agreements, which, among other things, limit PDCM's ability to pay dividends to us.

Our revolving credit facility has substantial restrictions and financial covenants and our ability to comply with those restrictions and covenants is uncertain. Our lenders can unilaterally reduce our borrowing availability based on anticipated commodity prices.

We depend in large part on our revolving credit facility for future capital needs. The terms of the credit agreement require us to comply with certain financial covenants and ratios. Our ability to comply with these restrictions and covenants in the future is uncertain and will be affected by the levels of cash flows from operations and events or circumstances beyond our control. Our failure to comply with any of the restrictions and covenants under the revolving credit facility or other debt agreements could result in a default under those agreements, which could cause all of our existing indebtedness to be immediately due and payable.

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the properties securing their loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under the revolving credit facility. Outstanding borrowings in excess of the borrowing base must be repaid immediately, or we must pledge other crude oil and natural gas properties as additional collateral. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility. Our inability to borrow additional funds under our revolving credit facility could adversely affect our operations and our financial results. PDCM is subject to each of the foregoing risks with respect to its revolving credit facility and its term loan agreement.

If we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there would be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed and would impact our ability to make principal and interest payments on our indebtedness and satisfy our other obligations.

Any default under the agreements governing our indebtedness, including a default under our revolving credit facility that is not waived by the required lenders, and the remedies sought by the holders of any such indebtedness, could make us unable to pay principal and interest on our indebtedness and satisfy our other obligations. If we are unable to generate sufficient cash flows and are otherwise unable to obtain funds necessary to meet required payments of principal and interest on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the instruments governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default, the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest, the lenders under our revolving credit facility could elect to terminate their commitments, cease making further loans and institute foreclosure proceedings against our assets, and we could be forced into bankruptcy or liquidation. If our operating performance declines, we may in the future need to seek to obtain waivers from the required lenders under our revolving credit facility to avoid being in default. If we breach our covenants under our revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our revolving credit facility, the lenders could exercise their rights as described above, and we could be forced into bankruptcy or liquidation. We cannot assure you that we will be granted waivers or amendments to our debt agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all. PDCM is subject to each of the foregoing risks with respect to its debt agreements. As of June 30 and September 30, 2013, PDCM was not in compliance with certain financial covenants in its debt agreements. It was able to obtain a waiver for these defaults from its lenders in July and October 2013, respectively. However, there can be no assurance that similar waivers will be available if needed in the future.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

Borrowings under our revolving credit facility bear interest at variable rates and expose us to interest rate risk. If interest rates increase, our debt service obligations on the variable rate indebtedness would increase although the amount borrowed remained the same, and our net income and cash available for servicing our indebtedness and for other purposes would decrease.

Notwithstanding our current indebtedness levels and restrictive covenants, we may still be able to incur substantial additional debt, which could exacerbate the risks described above.

We may be able to incur additional debt in the future. Although our debt agreements contain restrictions on our ability to incur indebtedness, those restrictions are subject to a number of exceptions. In particular, we may borrow under the revolving credit facility. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. Adding new debt to current debt levels could intensify the related risks that we and our subsidiaries now face.

Seasonal weather conditions and lease stipulations can adversely affect our operations.

Seasonal weather conditions and lease stipulations designed to protect wildlife affect operations in some areas. In certain areas drilling and other activities may be restricted or prohibited by lease stipulations, or prevented by weather conditions, for significant periods of time. This limits our operations in those areas and can intensify competition during the active months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to additional or increased costs or periodic shortages. These constraints and the resulting high costs or shortages could delay our operations and materially increase operating and capital costs and therefore adversely affect our profitability. Similarly, hot weather during some recent periods adversely impacted the operation of certain midstream facilities, and therefore our production. Similar events could occur in the future and could negatively impact our results of operations and cash flows.

We have limited control over activities on properties in which we own an interest but we do not operate, which could reduce our production and revenues.

We operate approximately 91% of the wells in which we own an interest. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of the underlying properties. The success and timing of drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator’s timing and amount of capital expenditures, expertise (including safety and environmental compliance) and financial resources, inclusion of other participants in drilling wells, and use of technology. The failure by an operator to adequately perform operations, or an operator’s breach of the applicable agreements, could reduce production and revenues and adversely affect our profitability. These risks have been increasing for us in recent years as our capital expenditures for non-operated projects have risen significantly, and are expected to rise further in 2014.

Our derivative activities could result in financial losses or reduced income from failure to perform by our counterparties or could limit our potential gains from increases in prices.

We use derivatives for a portion of the production from our own wells, our partnerships and for natural gas purchases and sales by our marketing subsidiary to achieve more predictable cash flows, to reduce exposure to adverse fluctuations in commodity prices, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us to the risk of financial loss in some circumstances, including when purchases or sales are different than expected or the counterparty to the derivative contract defaults on its contractual obligations. In addition, many of our derivative contracts are based on WTI or another oil or natural gas index price. The risk that the differential between the index price and the price we receive for the relevant production may change unexpectedly makes it more difficult to hedge effectively and increases the risk of a hedging-related loss. Also, derivative arrangements may limit the benefit we would otherwise receive from increases in the prices for the relevant commodity, and they may require the use of our resources to meet cash margin requirements. Since we do not designate our derivatives as hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of derivatives are recorded in our income statements, and our net income is subject to greater volatility than it would be if our derivative instruments qualified for hedge accounting. For instance, if commodity prices rise significantly, this could result in significant non-cash charges during the relevant period, which could have a material negative effect on our net income.

The inability of one or more of our customers or other counterparties to meet their obligations may adversely affect our financial results.

Substantially all of our accounts receivable result from our crude oil, natural gas and NGLs sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our derivatives as well as the derivatives used by our marketing subsidiary expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers or derivative counterparties may adversely affect our financial condition and profitability. We face similar risks with respect to our other counterparties, including the lenders under our revolving credit facility and the providers of our insurance coverage.

Our business could be negatively impacted by security threats, including cybersecurity threats, and other disruptions.
As a crude oil and natural gas producer, we face various security threats, including attempts by third parties to gain unauthorized access to sensitive information or to render data or systems unusable; threats to the safety of our employees; threats to the security of our infrastructure or third party facilities and infrastructure, such as processing plants and pipelines; and threats from terrorist acts. There can be no assurance that the procedures and controls we use to monitor these threats and mitigate our exposure to them will be sufficient in preventing them from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial condition, results of operations, or cash flows.
Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.
The occurrence of a significant accident or other event not fully covered by insurance or in excess of our insurance coverage could have a material adverse effect on our operations and financial condition. Insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. We also do not carry contingent business interruption insurance related to the purchasers of our production. In addition, pollution and environmental risks are generally not fully insurable.

We may not be able to keep pace with technological developments in our industry.
Our industry is characterized by rapid and significant technological advancements. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those or other new technologies at substantial cost. In addition, our competitors may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we were unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.
Competition in our industry is intense, which may adversely affect our ability to succeed.
Our industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce crude oil, natural gas and NGLs, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, larger companies may have a greater ability to continue exploration activities during periods of low commodity prices. Larger competitors may also be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which could adversely affect our competitive position. These factors could adversely affect the success of our operations and our profitability.
Acquisitions of properties are subject to the uncertainties of evaluating recoverable reserves and potential liabilities, including environmental uncertainties.
Acquisitions of producing properties and undeveloped properties have been an important part of our historical and recent growth. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future commodity prices, operating costs, title issues and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform engineering, environmental, geological and geophysical reviews of the acquired properties, which we believe are generally consistent with industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when

we inspect a well, we may not always discover structural, subsurface and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited. In addition, we often acquire acreage without any warranty of title except as to claims made by, through or under the transferor.

When we acquire properties, we will generally have potential exposure to liabilities and costs for environmental and other problems existing on the acquired properties, and these liabilities may exceed our estimates. Often we are not entitled to contractual indemnification associated with acquired properties. We often acquire interests in properties on an “as is” basis with no or limited remedies for breaches of representations and warranties. Therefore, we could incur significant unknown liabilities, including environmental liabilities, or losses due to title defects, in connection with acquisitions for which we have limited or no contractual remedies or insurance coverage. In addition, the acquisition of undeveloped acreage is subject to many inherent risks and we may not be able to realize efficiently, or at all, the assumed or expected economic benefits of acreage that we acquire.

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or may be in different geographic locations than our existing properties. These factors can increase the risks associated with an acquisition. Acquisitions also present risks associated with the additional indebtedness that may be required to finance the purchase price, and any related increase in interest expense or other related charges.

A failure to complete successful acquisitions would limit our growth.

Because our crude oil and natural gas properties are depleting assets, our future reserves, production volumes and cash flows depend on our success in developing and exploiting our current reserves efficiently and finding or acquiring additional recoverable reserves economically. Acquiring additional crude oil and natural gas properties, or businesses that own or operate such properties, when attractive opportunities arise is a significant component of our strategy. We may not be able to identify attractive acquisition opportunities. If we do identify an appropriate acquisition candidate, we may be unable to negotiate mutually acceptable terms with the seller, finance the acquisition or obtain the necessary regulatory approvals. If we are unable to complete suitable acquisitions, it will be more difficult to replace our reserves, and an inability to replace our reserves would have a material adverse effect on our financial condition and results of operations.

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

The administration of U.S. President Barack Obama has proposed to eliminate certain key U.S. federal income tax preferences currently available with respect to crude oil and natural gas exploration and production. The proposals include, but are not limited to (i) the repeal of the percentage depletion allowance for crude oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could result in higher federal income taxes, which could negatively affect our financial condition and results of operations. In addition, proposals are made from time to time in states where we operate to implement or increase severance or other taxes at the state level, and any such additional taxes would have similarly adverse effects on us.

Derivatives legislation and regulation could adversely affect our ability to hedge crude oil and natural gas prices and increase our costs and adversely affect our profitability.

In July 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”). The Dodd-Frank Act regulates derivative transactions, including our commodity hedging swaps, and could have a number of adverse effects on us, including the following:

- The Dodd-Frank Act may limit our ability to enter into hedging transactions, thus exposing us to additional risks related to commodity price volatility; commodity price decreases would then have an increased adverse effect on our profitability and revenues. Reduced hedging may also impair our ability to have certainty with respect to a portion of our cash flows, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.
- If, as a result of the Dodd-Frank Act or its implementing regulations, we are required to post cash collateral in connection with our derivative positions, this would likely make it impracticable to implement our current hedging strategy.
- Our derivatives counterparties will be subject to significant new capital, margin and business conduct requirements imposed as a result of the Dodd-Frank Act. We expect that these requirements will increase the cost to hedge because there will be fewer counterparties in the market and increased counterparty costs will be passed on to us.

The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms.

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

In December 2009, EPA published its findings that emissions of carbon dioxide, methane, and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings provide the basis for EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the CAA. In June 2010, EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the CAA's Prevention of Significant Deterioration ("PSD") and Title V permitting programs. This rule "tailors" these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to "best available control technology" ("BACT") standards. In its permitting guidance for greenhouse gases, issued in November 2010, EPA recommended options for BACT from the largest sources, which include improved energy efficiency, among others. EPA has recently issued a final rule retaining the current "tailored" permitting thresholds, opting not to extend greenhouse gas permitting requirements to smaller stationary sources at this time. EPA, however, intends to revisit these thresholds again by 2016. Should it do so, it is possible the onshore crude oil and natural gas sector will be included.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued an opinion and order in Coalition for Responsible Regulation v. Environmental Protection Agency, upholding EPA's greenhouse gas-related rules, including the "Tailoring Rule," against challenges from various state and industry group petitioners. In October 2013, the United States Supreme Court in Utility Air Regulatory Group v. EPA, accepted a petition for certiorari to decide whether EPA correctly determined that its regulation of greenhouse gases from mobile sources triggered permitting requirements under the CAA for stationary sources that emit greenhouse gases. The Court's decision is expected in the spring or summer of 2014 and will have significant implications for the regulation of greenhouse gases from stationary sources, including those in the oil and gas sector. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce and monitor emissions of greenhouse gases associated with our operations and also adversely affect demand for the crude oil and natural gas that we produce.

In the past, Congress has considered various pieces of legislation to reduce emissions of greenhouse gases. Congress has not adopted any significant legislation in this respect to date, but could do so in the future. For example, if Congress undertakes comprehensive tax reform in the coming year, it is possible that such measures could include a carbon tax, which could result in additional direct costs to our operations. In the absence of such national legislation, many states and regions have taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. For example, Colorado has proposed to directly regulate methane emissions from the oil and gas sector in its recently proposed oil and gas air emissions rules.

President Obama has indicated that climate change and greenhouse gas regulation is a significant priority for his second term. The President issued a Climate Action Plan in June 2013 that, among other things, calls for a reduction in methane emissions from the oil and gas sector. In November 2013, the President released an Executive Order charging various federal agencies, including EPA, with devising and pursuing strategies to improve the country's preparedness and resilience to climate change. In part through these executive actions, the direct regulation of methane emissions from the oil and gas sector continues to be a focus of regulation. In addition to the proposed Colorado rules discussed above, a lawsuit has been filed by several northeastern states that would require EPA to more stringently regulate methane emissions from the oil and gas sector. The passage of legislation, or executive and other initiatives that limit emissions of greenhouse gases from our equipment and operations, could require us to incur costs to reduce the greenhouse gas emissions, and it could also adversely affect demand for the crude oil and natural gas that we produce.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. Recent flooding in Colorado is an example of an extreme weather event that negatively impacted our operations. If such events were to continue to occur, or become more frequent, our operations could be adversely affected in various ways, including through damage to our facilities from increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term "global warming" as a shorthand for climate change, some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

The cost of defending any suits brought against us with respect to our royalty payment practices, and any judgments resulting from such suits, could have an adverse effect on our results of operations and financial condition.

In recent years, litigation has commenced against us and other companies in our industry regarding royalty practices and payments in jurisdictions where we conduct business. We intend to defend ourselves vigorously in these cases. The costs of defending these suits can be significant, even when we ultimately succeed in having them dismissed. These costs would be reflected in terms of dollar outlay, as well as the amount of time, attention and other resources that our management would have to appropriate to the defense. A judgment in favor of a plaintiff in a suit of this type could have a material adverse effect on our financial condition and profitability.

PDCM is dependent upon our equity partner and poses exit-related risks for us.

The board of managers of PDCM consists of three representatives appointed by us and three representatives appointed by our equity partner Lime Rock Partners, LP, each with equal voting power. The joint venture agreement generally requires the affirmative vote of a majority of the members of the board to approve an action, and we and Lime Rock may not always agree on the best course of action for the joint venture. If such a disagreement were to occur, we would not be able to cause the joint venture to take action that we believed to be in its best interests. Consequently, our best interests may not be advanced and our investment in the joint venture could be adversely affected. If there is a disagreement about a development plan and budget for the joint venture, Lime Rock is entitled to unilaterally suspend substantially all of the operations of the joint venture, which could have a material adverse impact on the results of operations of the joint venture and our investment. Such a suspension could last for up to two years, at which point either party could elect to dissolve the joint venture or to sell its ownership interests to a third party. Lime Rock is entitled in some cases to a preference with respect to liquidating distributions and proceeds from significant sales of ownership interests up to the amount of its contributed capital, which would diminish our returns if the value of the joint venture had declined at the time of the liquidation or sale.

Lime Rock is entitled to seek to sell its interest in the joint venture to a third party, subject to rights of first offer and refusal in favor of us. If we do not exercise those rights in a sale involving all of Lime Rock's ownership interests, Lime Rock can exercise "drag-along" rights and compel us to sell all of our interests in the proposed transaction. Accordingly, if we possessed insufficient funds and were unable to obtain financing necessary to purchase Lime Rock's interest under the rights of first offer and refusal, Lime Rock might sell its interests in the joint venture to a third party with whom we might have a difficult time dealing and in managing the joint venture or we may be required to sell our interest in the joint venture at a time when we may not wish to do so. Under these circumstances, our investment in the joint venture could be adversely affected.

Our articles of incorporation, bylaws, stockholders rights plan and Nevada law contain provisions that may have an anti-takeover effect and may delay, defer or prevent a tender offer or takeover attempt, which may adversely affect the market price of our common stock.

Our articles of incorporation authorize our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. We have adopted a stockholders rights plan that will dilute the stock ownership of certain acquirers of our common stock upon the occurrence of certain events. In addition, some provisions of our articles of incorporation, bylaws and Nevada law could make it more difficult for a third party to acquire control of us, including:

- the organization of our board of directors as a classified board, which allows no more than one-third of our directors to be elected each year;
- limitations on the ability of our shareholders to call special meetings; and
- certain Nevada anti-takeover statutes.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We have never declared or paid cash dividends on our common stock. We currently intend to retain all future earnings and other cash resources, if any, for the operation and development of our business and do not anticipate paying cash dividends in the foreseeable future. Payment of any future dividends will be at the discretion of our board of directors after taking into account many factors, including our financial condition, operating results, current and anticipated cash needs and plans for expansion. In addition, our revolving credit facility and the indenture governing our senior notes limit our ability to pay cash dividends on our common stock. Any future dividends may also be restricted by any debt agreements which we may enter into from time to time.

Our undeveloped acreage must be drilled before lease expiration to hold the acreage by production. In highly competitive markets for acreage, failure to drill sufficient wells to hold acreage could result in a substantial lease renewal cost or, if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Unless production is established within the spacing units covering the undeveloped acres on which some of our drilling locations are identified, our leases for such acreage will expire. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. As such, our actual drilling activities may differ materially from our current expectations, which could adversely affect our business.

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

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Leases in the Appalachia-Marcellus and Utica areas are particularly vulnerable to title deficiencies due the long history of land ownership in the area, resulting in extensive and complex chains of title. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 11, Commitments and Contingencies – Litigation, to our consolidated financial statements included elsewhere in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Our common stock, par value $0.01 per share, is traded on the NASDAQ Global Select Market under the symbol PDCE. The following table sets forth the range of high and low sales prices for our common stock for each of the periods presented:

	Price Range	
	High	Low
January 1 - March 31, 2012	$40.26	$28.61
April 1 - June 30, 2012	37.63	19.33
July 1 - September 30, 2012	34.25	23.27
October 1 - December 31, 2012	36.55	25.76
January 1 - March 31, 2013	53.80	33.39
April 1 - June 30, 2013	55.56	38.02
July 1 - September 30, 2013	66.03	51.46
October 1 - December 31, 2013	73.93	51.32

As of February 7, 2014, we had approximately 707 shareholders of record. Since inception, no cash dividends have been declared on our common stock. Cash dividends are restricted under the terms of our revolving credit facility and the indenture governing our 7.75% senior notes due 2022 and we presently intend to continue a policy of using retained earnings for expansion of our business. See Note 8, Long-term Debt, to our consolidated financial statements included elsewhere in this report.

The following table presents information about our purchases of our common stock during the three months ended December 31, 2013:

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share
October 1 - 31, 2013	1,086	$60.83
November 1 - 30, 2013	7,762	59.94
December 1 - 31, 2013	—	—
Total fourth quarter purchases	8,848	60.05

(1) Purchases primarily represent shares purchased from employees for the payment of their tax liabilities related to the vesting of securities issued pursuant to our stock-based compensation plans.

SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2013, with the cumulative total returns for the same period for the Standard and Poor's ("S&P") 500 Index and the Standard Industrial Code ("SIC") Index. The SIC Index is a weighted composite of 267 crude petroleum and natural gas companies. The cumulative total shareholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2008 and in the S&P 500 Index and the SIC Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended/As of December 31,				
	2013	2012	2011	2010	2009
	(in millions, except per share data and as noted)				
Statement of Operations (from continuing operations):					
Crude oil, natural gas and NGLs sales	$359.4	$238.4	$223.3	$146.0	$115.8
Commodity price risk management gain (loss), net	(23.9)	$32.3	46.1	59.9	(10.1)
Total revenues	411.3	320.6	337.3	276.6	169.6
Income (loss) from continuing operations	(26.5)	(21.7)	22.6	18.1	(62.8)
Earnings per share from continuing operations:					
Basic	$(0.82)	$(0.78)	$0.96	$0.94	$(3.71)
Diluted	(0.82)	(0.78)	0.95	0.92	(3.71)
Statement of Cash Flows:					
Net cash from:					
Operating activities	$159.2	$174.7	$166.8	$151.8	$143.9
Investing activities	(217.1)	(451.9)	(456.4)	(300.9)	(142.3)
Financing activities	248.7	271.4	243.4	171.5	(20.6)
Capital expenditures	394.9	347.7	334.5	162.7	143.0
Acquisitions of crude oil and natural gas properties	9.7	312.2	145.9	158.1	—
Balance Sheet:					
Total assets	$2,025.2	$1,826.8	$1,698.0	$1,389.0	$1,250.3
Working capital	112.4	(31.4)	(22.0)	16.2	32.9
Long-term debt	657.0	676.6	532.2	295.7	280.7
Total equity	967.6	703.2	664.1	642.2	538.6
Pricing and Lifting Costs Relating to Continuing Operations (per Boe):					
Average sales price (excluding net settlements on derivatives)	$48.37	$43.42	$48.37	$44.13	$34.12
Average lifting cost (1)	5.01	5.00	4.98	4.12	4.28
Production (MBoe):					
Production from continuing operations	7,429.5	5,489.9	4,616.2	3,383.3	3,393.4
Production from discontinued operations	1,127.8	2,835.3	3,304.5	3,056.1	3,820.7
Total production	8,557.3	8,325.2	7,920.7	6,439.4	7,214.1
Total proved reserves (MMBoe) (2)(3)(4)	265.8	192.8	169.3	143.4	119.6

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(1) Lifting costs represent lease operating expenses, excluding production taxes, on a per unit basis.

(2) Includes total proved reserves related to our Piceance Basin and NECO assets of 14.1 MMBoe, 59.5 MMBoe, 76.4 MMBoe and 68.3 MMBoe as of December 31, 2012, 2011, 2010 and 2009, respectively. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Piceance Basin and NECO assets.

(3) Includes total proved reserves related to our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin assets of 2 MMBoe, 3 MMBoe, 4 MMBoe and 8 MMBoe as of December 31, 2012, 2011, 2010 and 2009, respectively. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin assets.

(4) Includes total proved reserves related to our Permian Basin assets of 10.8 MMBoe and 5.4 MMBoe as of December 31, 2011 and 2010, respectively. Our Permian assets were held for sale as of December 31, 2011 and divested in February 2012. See Note 14, Assets Held for Sale, Divestitures and Discontinued Operations, to our consolidated financial statements included elsewhere in this report for additional details related to the divestiture of our Permian assets.

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

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our consolidated financial statements and related notes to consolidated financial statements included elsewhere in this report. Further, we encourage you to revisit the Special Note Regarding Forward-Looking Statements in Part I of this report.

EXECUTIVE SUMMARY

2013 Financial Overview

Crude oil, natural gas and NGLs sales from continuing operations increased in 2013 by $121.0 million, or 50.8%, compared to 2012. The growth in crude oil, natural gas and NGLs sales was the result of increased production and higher prices. For the month ended December 31, 2013, we maintained an average production rate of 27 MBoe per day. Production of 7.4 MMboe from continuing operations for the year ended December 31, 2013 represents an increase of 35% as compared to the year ended December 31, 2012, primarily attributable to our successful horizontal Niobrara and Codell drilling program in the Wattenberg Field. Crude oil production from continuing operations increased 46% in 2013, while NGLs production from continuing operations increased 25%. Our liquids percentage of total production from continuing operations was 53% in 2013 compared to 51% during 2012. Natural gas production from continuing operations increased 30% in 2013 compared to 2012.

Available liquidity as of December 31, 2013 was $647.0 million, including $16.1 million related to PDCM, compared to $398.6 million, including $14.1 million related to PDCM, as of December 31, 2012. Available liquidity is comprised of $193.2 million of cash and cash equivalents and $453.8 million available for borrowing under our revolving credit facilities. In August 2013, we completed a public offering of 5,175,000 shares of our common stock, par value $0.01 per share, at a price to us of $53.37 per share, for net proceeds of approximately $276 million, after deducting offering expenses and underwriting discounts. We expect to use the remaining net proceeds from the offering to fund a portion of our 2014 capital program and for general corporate purposes. We believe we have sufficient liquidity to allow us to execute our expanded drilling program through 2014. On October 31, 2013, we completed the semi-annual redetermination of our revolving credit facility's borrowing base. Our available borrowing base was reaffirmed at $450 million.

Operational Overview

Drilling Activities. During 2013, we continued to execute our strategic plan of increasing production while increasing our production mix of crude oil and NGLs by focusing our drilling operations primarily in the liquid-rich Wattenberg Field in Colorado and the emerging Utica Shale play in southeastern Ohio.

In the Wattenberg Field, we are currently running four drilling rigs and recently completed and are producing from our first 16 horizontal wells per section downspacing project. In 2013, we spudded 70 horizontal wells in the Wattenberg Field, 54 of which were completed, and participated in 49 gross, 10.4 net, horizontal non-operated drilling projects. In the Utica Shale, we spudded 11 horizontal wells in 2013, nine of which were completed and connected to a gathering line and two of which were in various stages of completion as of December 31, 2013. In the Appalachia-Marcellus Shale, PDCM spudded 14 horizontal wells in 2013, 10 of which were completed and turned-in-line as of December 31, 2013.

Divestiture of Crude Oil and Natural Gas Properties. In February 2013, we entered into a purchase and sale agreement with certain affiliates of Caerus pursuant to which we agreed to sell to Caerus our Piceance Basin, NECO and certain other non-core Colorado oil and gas properties, leasehold mineral interests and related assets. This divestiture was completed in June 2013 with total consideration of approximately $177.6 million, with an additional $17.0 million paid to our non-affiliated investor partners in our affiliated partnerships. The sale resulted in a pre-tax loss of $2.3 million. The proceeds from the asset divestiture were used to pay down our revolving credit facility and to fund a portion of our 2013 capital budget. Following the sale to Caerus, we do not have significant continuing involvement in the operations of, or cash flows from, the Piceance Basin and NECO oil and gas properties. Accordingly, the results of operations related to these assets have been separately reported as discontinued operations for all periods presented in our consolidated financial statements included elsewhere in this report.

In October 2013, we executed a purchase and sale agreement for the sale of our shallow Upper Devonian (non-Marcellus Shale) Appalachian Basin crude oil and natural gas properties owned directly by us, as well as through our proportionate share of PDCM. The properties consisted of approximately 3,500 gross shallow producing wells, related facilities and associated leasehold acreage, limited to the Upper Devonian and shallower formations. Substantially all of the divestiture closed in December 2013 for aggregate consideration of approximately $20.6 million, of which our share of the proceeds was approximately $5.1 million, subject to certain post-closing adjustments. Concurrent with the closing of the transaction, our $6.7 million irrevocable standby letter of credit and an agreement for firm transportation services was released and novated to the buyer. We retained all zones, formations and intervals below the Upper Devonian formation, including the Marcellus Shale, Utica Shale and Huron Shale, as well as the Marcellus-related midstream assets.

Colorado Flooding. In September 2013, we experienced widespread flooding in our Wattenberg Field operations in Weld County, Colorado, which resulted in a shut-in of approximately 200 vertical wells, approximately 40 of which remained shut-in as of December 31, 2013. Through December 31, 2013, we have expensed approximately $0.9 million and have capitalized approximately $1.1 million as a result of performing remediation operations. Assessment of the full economic impact of the flooding is ongoing and we expect to incur approximately $1 million to $2 million in additional costs during the first quarter of 2014 to replace damaged well equipment and to bring vertical wells back on-line.

2014 Operational Outlook

We expect our production for 2014 to range between 9.5 MMBoe to 10 MMBoe. Our 2014 $647 million capital budget, of which $16 million represents our share of PDCM's capital budget, is expected to be used primarily for development drilling and selective acquisition of additional acreage. This budget includes $576 million of development capital and $71 million for leasehold acquisitions, exploration and other expenditures. We may revise our capital budget during the year as a result of, among other things, acquisitions or dispositions of assets, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows.

Wattenberg Field. We expect to invest approximately $467 million in the Wattenberg Field in 2014, continuing with a four-rig drilling program with plans to add a fifth operated horizontal drilling rig in the second quarter of 2014. We plan to spud 115 gross operated horizontal wells, comprised of 59 horizontal Codell wells and 56 horizontal Niobrara wells. Approximately $100 million of the total Wattenberg Field capital budget is expected to be allocated to non-operated projects, including participation in a 26-well pad in the Niobrara formation in the northeastern portion of the core Wattenberg Field. We also plan to reinitiate a modest vertical well refracturing program.

Utica Shale. We expect to invest approximately $162 million in the Utica Shale to spud 18 horizontal wells, including eight wells in our northern acreage and 10 wells in our southern acreage. A second drilling rig is expected to be deployed in the second half of 2014. The Utica capital budget includes approximately $30 million to acquire additional contiguous leasehold.

Marcellus Shale. PDCM's 2014 capital budget is $32 million, of which $16 million represents our share, and is expected to be utilized to finalize drilling and completion operations on horizontal wells that were in-process at December 31, 2013 and for midstream infrastructure. PDCM's capital budget is expected to be funded by PDCM's operating activities, borrowing under its credit facility or other financing transactions. PDCM has elected to temporarily suspend drilling activities in the Marcellus Shale.

Non-U.S. GAAP Financial Measures

We use "adjusted cash flows from operations," "adjusted net income (loss)," "adjusted EBITDA" and "PV-10," non-U.S. GAAP financial measures, for internal management reporting, when evaluating period-to-period changes and, in some cases, providing public guidance on possible future results. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, net income (loss) or cash flows from operations, investing or financing activities, or standardized measure, as applicable, and should not be viewed as liquidity measures or indicators of cash flows reported in accordance with U.S. GAAP. The non-U.S. GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-U.S. GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure. See Reconciliation of Non-U.S. GAAP Financial Measures for a detailed description of these measures, as well as a reconciliation of each to the most comparable U.S. GAAP measure.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results from continuing operations:

	Year Ended December 31,			Percent Change	
	2013	2012	2011	2013-2012	2012-2011
	(dollars in millions, except per unit data)				
Production (1)					
Crude oil (MBbls)	2,909.7	1,987.8	1,675.7	46.4 %	18.6 %
Natural gas (MMcf)	20,859.6	15,988.6	13,370.1	30.5 %	19.6 %
NGLs (MBbls)	1,043.2	837.3	712.1	24.6 %	17.6 %
Crude oil equivalent (MBoe) (2)	7,429.5	5,489.9	4,616.2	35.3 %	18.9 %
Average MBoe per day	20.4	15.0	12.6	36.0 %	19.0 %
Crude Oil, Natural Gas and NGLs Sales					
Crude oil	$261.6	$173.5	$147.2	50.8 %	20.4 %
Natural gas	68.6	42.0	49.3	63.3 %	(14.8)%
NGLs	29.2	22.9	26.8	27.5 %	(14.6)%
Total crude oil, natural gas and NGLs sales	$359.4	$238.4	$223.3	50.8 %	6.8 %
Net Settlements on Derivatives (3)					
Natural gas	$16.0	$49.9	$29.1	(67.9)%	71.5 %
Crude oil	(3.1)	(0.5)	(11.9)	*	(95.8)%
Total net settlements on derivatives	$12.9	$49.4	$17.2	(73.9)%	187.2 %
Average Sales Price (excluding net settlements on derivatives)					
Crude oil (per Bbl)	$89.92	$87.27	$87.44	3.0 %	