

PETROLEUM DEVELOPMENT CORP
Form 10-K
March 04, 2010

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

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

PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)

Nevada
(State of Incorporation)

95-2636730
(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 \$.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 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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 Accelerated filer

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2009, was \$228,721,681 (based on the then closing price of \$15.69).

As of February 16, 2010, there were 19,240,478 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form is incorporated by reference to our definitive proxy statement to be filed pursuant to Regulation 14A for our 2010 Annual Meeting of Shareholders.

PETROLEUM DEVELOPMENT CORPORATION
2009 ANNUAL REPORT ON FORM 10-K
TABLE OF CONTENTS

PART I		Page
<u>Item 1.</u>	<u>Business</u>	2
<u>Item 1A.</u>	<u>Risk Factors</u>	17
<u>Item 1B.</u>	<u>Unresolved Staff Comments</u>	26
<u>Item 2.</u>	<u>Properties</u>	27
<u>Item 3.</u>	<u>Legal Proceedings</u>	27
<u>Item 4.</u>	<u>[Reserved]</u>	27
PART II		
<u>Item 5.</u>	<u>Market for Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities</u>	27
<u>Item 6.</u>	<u>Selected Financial Data</u>	29
<u>Item 7.</u>	<u>Management’s Discussion and Analysis of Financial Condition and Results of Operations</u>	30
<u>Item 7A.</u>	<u>Quantitative and Qualitative Disclosures About Market Risk</u>	47
<u>Item 8.</u>	<u>Financial Statements and Supplementary Data</u>	49
<u>Item 9.</u>	<u>Changes in and Disagreements With Accountants on Accounting and Financial Disclosure</u>	49
<u>Item 9A.</u>	<u>Controls and Procedures</u>	49
<u>Item 9B.</u>	<u>Other Information</u>	49
PART III		
<u>Item 10.</u>	<u>Directors, Executive Officers and Corporate Governance</u>	49
<u>Item 11.</u>	<u>Executive Compensation</u>	49
<u>Item 12.</u>	<u>Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters</u>	50
<u>Item 13.</u>	<u>Certain Relationships and Related Transactions, and Director Independence</u>	50
<u>Item 14.</u>	<u>Principal Accounting Fees and Services</u>	50
PART IV		
<u>Item 15.</u>	<u>Exhibits, Financial Statement Schedules</u>	50
<u>SIGNATURES</u>		51
<u>GLOSSARY OF NATURAL GAS AND OIL TERMS</u>		52

Table of Contents

PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references to "PDC," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation, together with its wholly owned subsidiaries, entities in which it has a controlling financial interest and proportionate share of its sponsored drilling partnerships.

GLOSSARY OF NATURAL GAS AND OIL TERMS

Words defined in the Glossary of Natural Gas and Oil Terms are set in boldface type the first time they appear.

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One oil barrel or 42 gallons of liquid volume.

Bcf – One billion cubic feet of natural gas volume.

Bcfe – One billion cubic feet of natural gas equivalent.

Btu – British thermal unit.

MBbls – One thousand oil barrels.

Mcf – One thousand cubic feet of natural gas volume.

Mcfe – One thousand cubic feet of natural gas equivalent (six Mcf of natural gas equals one Bbl of oil).

Mmbtu – One million British thermal units.

Mmcf – One million cubic feet of natural gas volume.

Mmcfe – One million cubic feet of natural gas equivalent.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission ("SEC"). Our SEC filings are available free of charge from the SEC's website at www.sec.gov or from our website at www.petd.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 Petroleum Development Corporation, Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call toll free 800-624-3821.

In addition to our SEC filings, our website can be used to access other information, including our recent news releases, bylaws, committee charters, code of business conduct and ethics, shareholder communication policy, director nomination procedures and our whistleblower hotline. However, the information available on our website is not part of this report and is not hereby incorporated by reference.

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. 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, which include statements of estimated natural gas and oil production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management's strategies, plans and objectives. However, these 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 risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of natural gas and oil, 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 production volumes, worldwide demand and commodity prices for natural gas and oil;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
 - our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
 - the availability and cost of capital to us;
 - risks incident to the drilling and operation of natural gas and oil wells;
 - future production and development costs;

Table of Contents

- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America ("U.S.");
 - the effect of natural gas and oil derivatives activities;
 - conditions in the capital markets; and
 - losses possible from pending or future litigation.

Further, we urge you to carefully review and consider the disclosures made in this report, including the risks and uncertainties that may affect our business as described herein under Item 1A, Risk Factors, and our other filings with the SEC. 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.

ITEM 1. BUSINESS

Overview

We are an independent energy company engaged in the exploration for and the acquisition, development, production and marketing of natural gas and oil. Since we began natural gas and oil operations in 1969, we have grown through drilling and development activities, acquisitions of producing natural gas and oil wells and the expansion of our natural gas marketing business.

During 2009, we managed our balance sheet in an effort to ensure that we had sufficient liquidity during an uncertain economic environment and we intend to maintain this spending discipline going forward. We focused our efforts on our ability to control spending by concentrating on cost reductions in lease operating expenses and per well capital expenditures and limiting our capital budget to be within our expected operating cash flows. Additionally, we raised capital through an equity offering and asset monetization through the formation of our Appalachian joint venture.

Based on unstable economic conditions existing early in 2009 and uncertainty as to when commodity and financial markets would recover to a perceived normal level, we reduced our planned 2009 capital expenditures to \$108 million, or approximately 33% of our 2008 level. Additionally, we targeted our drilling dollars in the oil-rich section of the Wattenberg Field in our Rocky Mountain Region to take advantage of the pricing of oil over natural gas. Then, in August 2009, we completed an underwritten public offering of 4.3 million shares of the Company's common stock at a price of \$12.00 per share for net proceeds of \$48.5 million. Finally, in October 2009, we entered into a joint venture arrangement with an unaffiliated party that monetized a portion of our Appalachian Basin assets. We entered into the joint venture with Lime Rock Partners ("Lime Rock") primarily to develop our Marcellus Shale acreage in the Appalachian Basin. At closing, we received a return of capital payment of \$45 million. Upon the fulfillment of Lime Rock's commitment to provide future operational funding of \$68.5 million, Lime Rock will earn a 50% interest in our Appalachian assets, exclusive of our interest in our affiliated partnerships' wells. We do not expect to make any capital contributions to the joint venture in 2010 or until Lime Rock achieves a 50% interest, which is expected to occur in 2011.

Business Strategy

Our primary objective is to increase shareholder value through the growth of our reserves and production, while operating our properties in an efficient manner to maximize the cash flow and earnings potential of our assets.

Drill and Develop. Our acreage holdings include positions primarily in the Rocky Mountain Region and, through our joint venture, the Appalachian Basin. We believe that we will be able to continue to drill a substantial number of new wells on our current undeveloped properties. As of December 31, 2009, we had approximately 2,285 gross drill sites available in the Rocky Mountain Region and, through our joint venture, 569 gross drill sites available in the Appalachian Basin. In 2010, we plan to drill approximately 226 gross, 188.5 net, development wells in our Rocky Mountain Region and 26 gross wells, 15.6 net wells, targeted for the Marcellus Shale in the Appalachian Basin.

Rocky Mountain Region. Our primary focus in the Rocky Mountain Region is on developmental drilling in the Wattenberg Field and in Northeastern Colorado, or NECO, (both located in the DJ Basin) and the Grand Valley Field in the Piceance Basin. We seek to maximize the value of our existing wells through a program of well recompletions, refractures and workovers. In 2010, we plan to workover 50 wells and recomplete and/or refrac 12 wells.

Table of Contents

Appalachian Basin. Historically, our focus was on developmental drilling, targeting predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs. In 2009, our focus shifted to that of exploratory drilling, targeting the Marcellus Shale formation in West Virginia and Pennsylvania. In 2010, through our joint venture, our preliminary budget includes plans to drill 26 development wells targeting the Marcellus and 50 recompletes and 29 workovers targeting the shallow Devonian.

Strategically Acquire. Our acquisition efforts focus on producing properties that have a significant undeveloped acreage component. When weighing potential acquisitions, we prefer properties that have most of their value in producing wells, behind pipe reserves and high quality proved undeveloped locations. Historically, acquisitions have offered efficiency improvements through economies of scale in management and administration costs. During the period December 2006 through October 2007, we completed a series of asset and company acquisitions, three in our core operating area of the Rocky Mountain Region and two in the Appalachian Basin. While we had no significant acquisitions of properties in 2008 or 2009, we continue to identify and evaluate acquisition opportunities that will enhance our current properties and provide an opportunity to explore and develop new prospects.

Manage Risk. Historically, we have concentrated on development drilling and geographical diversification to reduce risk levels associated with natural gas and oil drilling, production and markets. Currently, a majority of our proved reserves are located in the Rocky Mountain Region. However, we benefit from operational diversity in the Rocky Mountain Region by maintaining significant activity and production in three separate areas, including the Wattenberg Field in north central Colorado and the NECO area, both located in the DJ Basin, and the Grand Valley Field in the Piceance Basin in western Colorado. Additionally, we regularly review opportunities to further diversify into other regions where we can apply our operational expertise. We believe development drilling will remain the foundation of our drilling activities in the future because it is less risky than exploratory drilling and is likely to generate cash returns more quickly. In addition to improving our liquidity position, the formation of the joint venture serves to mitigate the risks associated with exploring our Marcellus rights. We view exploratory activities as having the potential to identify new development opportunities at a cost competitive with the current cost of acquiring proven locations.

We maintain a conservative financial approach and proactively employ strategies to reduce the effects of commodity price volatility to help manage the risks associated with the oil and natural gas industry (the "industry"). We use natural gas and oil derivatives contracts primarily to reduce the effects of volatile commodity prices. At any given time, we have derivative contracts in place on a varying portion of our production; however, pursuant to our derivative policy, all volumes for derivatives contracts are limited to 80% of our future production from producing wells at the time we enter into the derivative contracts, with the exception of put contracts, or floors, for which volumes are not limited. As of December 31, 2009, we had natural gas and oil hedges in place covering 66.2% of our expected natural gas production and 59.8% of our expected oil production in 2010. Further, while our derivative instruments are utilized to manage the impact of price volatility of our natural gas and oil production, we have elected not to formally designate these instruments as hedging instruments and therefore, we do not use hedge accounting. Accordingly, we are required to recognize changes in the fair value of our derivative instruments in earnings each reporting period and, therefore, have the potential for significant earnings volatility. Our policy prohibits the use of natural gas and oil derivative instruments for speculative purposes. See Note 2, Summary of Significant Accounting Policies – Derivative Financial Instruments and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

Business Segments

We divide our operating activities into two segments: natural gas and oil sales and natural gas marketing. See Note 14, Business Segments, to our consolidated financial statements included in this report.

Natural Gas and Oil Sales. Our natural gas and oil sales segment primarily reflects revenues and expenses from the production and sale of natural gas and oil. During 2009, natural gas and oil represented 82.1% and 17.9% of our total production volumes, respectively, with 87% of our total production being generated by our Rocky Mountain Region properties and 9.4% by our Appalachian Basin properties. The majority of our undeveloped acreage is in our Rocky Mountain Region, where our 2009 drilling activities were focused and will continue to be the focus in 2010.

We operate approximately 92.7% of the wells in which we own a working interest. With respect to wells we operate and own an interest of less than 100%, we charge the other working interest owners, including our drilling partnerships, a competitive fee for operating the well and transporting natural gas. Revenues and expenses related to our well operations and transportation of natural gas are included in our natural gas and oil sales segment.

Natural Gas Marketing. Our natural gas marketing segment is comprised of our wholly-owned subsidiary Riley Natural Gas ("RNG"), through which we purchase, aggregate and resell natural gas produced by us and others. This allows us to diversify our operations beyond natural gas drilling and production. Through RNG, we have established relationships with many of the natural gas producers in the Appalachian Basin and have gained significant expertise in the natural gas end-user market.

Table of Contents

Areas of Operations

The following map presents the general locations of our exploration, development and production activities as of December 31, 2009.

We focus our exploration, development and production efforts primarily in two geographic areas: the Rocky Mountain Region and the Appalachian Basin. The majority of our undeveloped acreage is in the Rocky Mountain Region and our current drilling plans continue to be focused predominantly in this area.

Rocky Mountain Region. Our Rocky Mountain Region is divided into three major operating areas: (1) Grand Valley Field, (2) Wattenberg Field and (3) NECO area. Our Rocky Mountain Region includes approximately 293,600 gross acres of leasehold and 2,524 gross, 1,654.3 net, natural gas and oil wells in which we own an interest.

- Grand Valley Field, Piceance Basin, Garfield County, Colorado. Development wells drilled in the area range from 7,000 to 9,500 feet in depth and the majority of wells are drilled directionally from multi-well pads generally ranging from two to ten wells per drilling pad. The primary target in the area is gas reserves, developed from multiple sandstone reservoirs in the Mesaverde Williams Fork formation. Well spacing is approximately ten acres per well.
- Wattenberg Field, DJ Basin, Weld County, Colorado. Wells drilled in the area range from approximately 7,000 to 8,000 feet in depth and generally target natural gas and oil reserves in the Niobrara, Codell and J Sand reservoirs. Well spacing ranges from 20 to 40 acres per well. Operations in the area, in addition to the drilling of new development wells, include the frac of Codell and Niobrara reservoirs in existing wellbores whereby the Codell sandstone reservoir is fraced a second time and/or initial completion attempts are made in the slightly shallower Niobrara carbonate reservoir. Unlike our other two Rocky Mountain areas, the Wattenberg Field produces a significant amount of oil and, to a lesser extent, natural gas liquids.
- NECO area, DJ Basin, Yuma County, Colorado and Cheyenne County, Kansas. Wells drilled in the area range from approximately 1,500 to 3,000 feet in depth and target gas reserves in the shallow Niobrara reservoir. Well spacing is approximately 40 acres per well. Drilling operations range from exploratory wells to test undrilled, seismically defined, structural features at the Niobrara horizon to development wells targeting known reserves in existing identified features.

Table of Contents

•Other Rocky Mountain Region Areas. We currently own an interest in 14 gross, 5 net, natural gas and oil wells in Burke County, North Dakota and 3 gross, 0.7 net, oil wells in Wyoming. As of December 31, 2009, our remaining North Dakota leasehold encompasses approximately 58,400 gross acres with approximately 25,600 net undeveloped acres remaining for development and our Wyoming leasehold encompasses approximately 19,200 gross and net undeveloped acres. We currently have no drilling activity planned for these areas in 2010.

Appalachian Basin. We own an interest in approximately 271 gross, 88.5 net, natural gas and oil wells in West Virginia, Pennsylvania and Tennessee outside of our interest in our joint venture with Lime Rock. Additionally, in association with the joint venture, we own an interest in approximately 1,980 gross, 1,586.4 net, wells. Wells located in this area are approximately 4,500 feet deep and target predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs.

Other Areas. We own an interest in approximately 210 gross, 146.5 net, natural gas and oil wells in the Michigan Basin that produced 1.4 Bcfe net to our interest in 2009. As of December 31, 2009, our remaining Michigan leasehold encompasses 10,000 gross, 8,500 net, undeveloped acres. Wells in the area range from 1,000 to 2,500 feet in depth and produce gas from the Antrim Shale. We also hold a total of 27,200 gross, 21,500 net, undeveloped acres in New York and Texas. We currently have no drilling activity planned for these three areas in 2010.

The table below presents our productive wells by operating area at December 31, 2009.

Location	Productive Wells				Total	
	Natural Gas		Oil		Gross	Net
	Gross	Net	Gross	Net		
Rocky Mountain Region						
Wattenberg	1,459	944.7	25	19.2	1,484	963.9
Grand Valley	306	180.4	-	-	306	180.4
NECO	717	504.3	-	-	717	504.3
Other	5	1.3	12	4.4	17	5.7
Total Rocky Mountain Region	2,487	1,630.7	37	23.6	2,524	1,654.3
Appalachian Basin (1)	2,212	1,659.4	39	15.5	2,251	1,674.9
Other	208	148.8	7	2.7	215	151.5
Total productive wells	4,907	3,438.9	83	41.8	4,990	3,480.7

(1) Includes 100% of the wells owned by the joint venture.

Operations

Prospect Generation

Our staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. They utilize results from logs, seismic data and other tools to evaluate existing wells and to predict the location of economically attractive new natural gas and oil reserves. To further this process, we have collected and continue to collect logs, core data, production information and other raw data available from state and private agencies and other companies and individuals actively drilling in the regions being evaluated. From this information, the geologists develop models of the subsurface structures and formations that are used to predict areas for prospective economic development.

On the basis of these models, our land department obtains available natural gas and oil leaseholds, farm-outs and other development rights in these prospective areas. In most cases, to secure a lease, we pay a lease bonus and an annual rental payment, converting, upon initial production, to a royalty. In addition, overriding royalty payments may be granted to third parties in conjunction with the acquisition of drilling rights initially leased by others. See a summary of our acreage available for development below.

Table of Contents

Financing of Company Drilling and Development Activities

We have historically funded our drilling and development activities through our cash flows from operations, capital provided from our credit facility, sale of leaseholds, a senior notes issuance and, in August 2009, an equity offering. Further, in October 2009, we entered into a joint venture arrangement that monetized a portion of our Appalachian Basin assets in which we received \$45 million as a return of capital and provides for future operational funding of \$68.5 million in the same area. In addition to any combination of our historical sources, future sources of funding may include, but not limited to, volumetric production payments, debt securities and convertible debt securities.

Purchases of Producing Properties

In addition to drilling new wells, we continue to pursue opportunities to purchase existing wells and development rights from other owners, as well as greater ownership interests in the wells we operate. Generally, outside interests purchased include a majority interest in the wells and the right to operate the wells. In January 2007, we completed the purchase from an unrelated party of approximately 144 natural gas and oil wells and 8,160 acres of leaseholds in the Wattenberg Field. Also in January 2007, we purchased the outside partnership interests in 44 partnerships which we sponsored and formed primarily in the late 1980s and 1990s. These interests constituted the majority of the interests in 718 wells, primarily in the Appalachian and Michigan Basins. In February 2007, we acquired from an unrelated party 28 producing wells and associated undeveloped acreage in Colorado. In October 2007, we purchased from unrelated parties a majority working interest of 762 natural gas wells located in southwestern Pennsylvania. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage. No significant acquisitions were made in 2008 or 2009.

Title to Properties

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the industry. As is customary in the industry, a preliminary title examination is conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial 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 to the industry. The properties may also be subject to additional burdens, liens or encumbrances customary to the industry, including items such as operating agreements, current taxes, development obligations under natural gas and oil leases, farm-out agreements and other restrictions. We do not believe that any of these burdens will materially interfere with the use of the properties.

Acreage

The following table presents, by operating area, leased acres as of December 31, 2009.

Location	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region						
Wattenberg	48,400	45,500	23,800	19,400	72,200	64,900
Grand Valley	2,700	2,700	5,300	5,300	8,000	8,000
NECO	23,600	19,600	103,500	85,500	127,100	105,100

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Other	8,700	4,700	77,600	44,800	86,300	49,500
Total Rocky Mountain Region	83,400	72,500	210,200	155,000	293,600	227,500
Appalachian Basin (1)	109,600	106,800	11,300	10,800	120,900	117,600
Other	17,200	15,200	37,200	30,000	54,400	45,200
Total acreage	210,200	194,500	258,700	195,800	468,900	390,300

(1)Includes 100% of the acreage related to the joint venture.

Table of Contents

Drilling Activities

The following table presents our development and exploratory drilling activity for the last three years. 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 producing wells and wells capable of commercial production.

	2009		Drilling Activity 2008		2007	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Productive (1)						
Rocky Mountain Region	87	68.2	289	243.8	316	247.9
Appalachian Basin	2	2.0	60	60.0	8	8.0
Other	-	-	-	-	3	3.0
Total productive	89	70.2	349	303.8	327	258.9
Dry						
Rocky Mountain Region	2	1.0	8	8.0	11	9.7
Appalachian Basin	-	-	-	-	-	-
Other	-	-	-	-	-	-
Total dry	2	1.0	8	8.0	11	9.7
Total development	91	71.2	357	311.8	338	268.6
Exploratory:						
Productive (1)						
Rocky Mountain Region	2	1.0	4	4.0	1	0.2
Appalachian Basin	5	5.0	-	-	-	-
Other	-	-	3	3.0	-	-
Total productive	7	6.0	7	7.0	1	0.2
Dry						
Rocky Mountain Region	-	-	7	7.0	7	4.5
Appalachian Basin	-	-	-	-	-	-
Other	-	-	3	2.6	-	-
Total dry	-	-	10	9.6	7	4.5
Pending determination	2	2.0	5	5.0	3	3.0
Total exploratory	9	8.0	22	21.6	11	7.7
Total drilling activity	100	79.2	379	333.4	349	276.3
Recompletions/refractures	32	30.6	125	106.9	181	155.3

(1)As of December 31, 2009, a total of 19 productive wells were waiting to be fractured and/or for gas pipeline connection, of which 10 were connected and turned in line by February 15, 2010.

Table of Contents

The following table presents the wells drilled, by operating area, during the last three years, as well as our planned 2010 drilling activity.

	Planned		2009		2008		2007	
	2010 Gross	Gross	Net	Gross	Net	Gross	Net	
Rocky Mountain Region								
Wattenberg	180	82	65.2	149	122.7	158	106.0	
Grand Valley	21	1	1.0	62	54.4	53	41.7	
NECO	25	8	4.5	98	88.2	123	115.0	
Other	-	1	0.5	2	0.5	3	1.6	
Total Rocky Mountain Region	226	92	71.2	311	265.8	337	264.3	
Appalachian Basin (1)	26	8	8.0	62	62.0	8	8.0	
Other	-	-	-	6	5.6	4	4.0	
Total wells planned/drilled	252	100	79.2	379	333.4	349	276.3	

(1) During 2009, 7 gross wells were drilled prior to the formation of the joint venture and 1 was drilled subsequent to its formation. The drilling activity planned for 2010 will be conducted for the benefit of the joint venture and funded by our joint venture partner.

Much of the work associated with drilling, completing and connecting wells, including fracturing, logging and pipeline construction is performed by subcontractors, under our direction, specializing in those operations, as is common in the industry. When judged advantageous, we acquire materials and services used in the development process through competitive bidding by approved vendors. We also directly negotiate rates and costs for services and supplies when conditions indicate that such an approach is warranted.

Drilling and Development Activities Conducted for Company Sponsored Partnerships

We began sponsoring drilling partnerships in 1984, and had sponsored one or more every year through 2007. For many years, our drilling partners were primarily the public and private partnerships we sponsored. At closing, we contributed a cash investment to purchase an interest in the drilling and development activities of the partnership and then serve as the managing general partner. As wells produce for a number of years, we continue to serve as operator for 33 partnerships, as well as for other unaffiliated parties.

When developing wells for our partnerships or others, we entered into a development agreement with the investor partner, pursuant to which we agreed to sell some or all of our rights in a well to be drilled to the partnership or other entity. The partnership or other entity thereby became an owner of a working interest in the well. In our financial reporting, we report only our proportionate share of natural gas and oil reserves, production, natural gas and oil sales and costs associated with wells in which we have a noncontrolling financial interest.

In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008. We affirmed this position in 2009 to change our business model from a partnership sponsor to that of an independent exploration and production company. Under our previous model, we drilled both partnership wells and wells for our own account. In the case of the partnership wells, we effectively limited drilling and operating risk borne by us to generally 20% to 37% of the total cost of the drilling activity. Since we have discontinued the partnership sponsor model, our composite exposure to risks associated with drilling and operating natural gas and oil properties have increased because we drill and operate all natural gas and oil wells using our operating cash flows and debt.

Drilling and Development Activities Conducted for Appalachian Joint Venture

With the formation of our joint venture arrangement with Lime Rock, we are able to engage in extensive drilling activities in the Appalachian Basin using capital of \$68.5 million committed by our joint venture partner. After our joint venture partner achieves a 50% interest in the joint venture, all future funding of capital will be shared equally. While sharing the risk inherent in exploratory drilling, we are still able to maintain a portion of the potential benefits associated with such risk.

In our financial reporting, as of and for the year ended December 31, 2009, we consolidated the natural gas and oil revenues, production, natural gas and oil sales and costs associated with the wells within the joint venture which we have a controlling financial interest.

Table of Contents

Natural Gas and Oil Reserves

All of our natural gas and oil reserves are located in the U.S. Our reserve estimates are prepared with respect to reserve categorization, using the definitions for proved reserves set forth in SEC Regulation S-X, Rule 4-10(a) and subsequent SEC staff regulations, interpretations and guidance. All of our proved natural gas and oil reserves, including reserves held by consolidated companies and our proportionate share of our affiliates partnerships, have been estimated by independent consultants.

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 review includes, but is not limited to, confirmation that reserve estimates (1) include all properties owned; (2) are based on proper working and net revenue interests; and (3) reflect reasonable cost estimates and field performance. The internal team compiles the reviewed data and forwards the data to independent consulting firms engaged to estimate our reserves.

For each of the years in the three-year period ended December 31, 2009, our reserve estimates for the Rocky Mountain Region and Fort Worth Basin, approximately 89% of our total proved reserves, are based on reserve reports prepared by Ryder Scott Company, L.P. and for the Appalachian and Michigan Basins are based on reserve reports prepared by Wright & Company. When preparing our reserve estimates, the independent engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, natural gas and oil production, 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.

The independent petroleum engineers prepare an estimate of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to assure that the reserve estimates are complete, determined by acceptable industry methods and to a level of detail we deem appropriate. The final independent petroleum engineers' estimated reserve reports are reviewed and approved by our engineering staff and management.

The professional qualifications of the lead engineer primarily responsible for overseeing the preparation of our reserve estimate meet the standards of 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 employee holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering and has over 25 years of experience in reservoir engineering. The individual is a member of the Society of Petroleum Engineers, allowing the individual to remain current with the developments and trends in the industry. Further, during 2009, this individual attended ten hours of formalized training relating to the definitions and disclosure guidelines set forth in the SEC's final rule released January 2009, Modernization of Oil and Gas Reporting.

The tables below present information regarding our estimated proved reserves. Reserves cannot be measured exactly, because reserve estimates involve judgments. 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 present value of estimated future net cash flows nor the standardized measure is intended to represent the current market value of the estimated natural gas and oil reserves we own. For additional information regarding both of these measures, see the Natural Gas and Oil Operations section of the supplemental information provided with our consolidated financial statements included in this report.

	2009	December 31, 2008	2007
Proved reserves			

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Natural gas (MMcf)	608,925	662,857	593,563
Oil (MBl)	18,070	15,037	15,338
Total proved reserves (MMcfe)	717,345	753,079	685,591
Proved developed reserves (MMcfe)	295,839	329,669	317,884
Estimated future net cash flows (in thousands)(1)	\$ 764,111	\$ 1,056,890	\$ 1,847,485
Standardized measure (in thousands) (1)(2)	\$ 347,636	\$ 356,805	\$ 753,071

(1) Estimated future net cash flow represents the undiscounted estimated future gross revenue to be generated from the production of proved reserves, net of estimated production costs, future development costs and income tax expense.

Table of Contents

Prices used to estimate future gross revenues and production and development costs were based on the following:

- Gross revenues

- For 2009, a 12-month average price calculated as the unweighted arithmetic average of the price on the first day of each month, January through December.
 - For 2007 and 2008, prices in effect as of December 31 for the respective year.
- Prices for each of the three years were adjusted by lease for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity hedges.

- Production and development costs

- Prices as of December 31 for each of the respective years presented.
- The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization expense.

(2) The standardized measure of discounted future net cash flow represents the present value of estimated future net cash flows discounted at a rate of 10% per annum to reflect timing of future cash flows.

	December 31, 2009				
	Natural Gas	Oil	Natural Gas Equivalent	Percent	
	(MMcf)	(MBbl)	(MMcfe)		
Proved developed					
Rocky Mountain Region					
Wattenberg	55,233	5,675	89,283	30	%
Grand Valley	101,504	243	102,962	34	%
NECO	31,463	-	31,463	11	%
Other	361	251	1,867	1	%
Total Rocky Mountain Region	188,561	6,169	225,575	76	%
Appalachian Basin					
Other	55,008	34	55,212	19	%
Total proved developed	14,806	41	15,052	5	%
Total proved developed	258,375	6,244	295,839	100	%
Proved undeveloped					
Rocky Mountain Region					
Wattenberg	70,838	11,552	140,150	33	%
Grand Valley	273,875	274	275,519	66	%
Total Rocky Mountain Region	344,713	11,826	415,669	99	%
Appalachian					
Total proved undeveloped	5,837	-	5,837	1	%
Total proved undeveloped	350,550	11,826	421,506	100	%
Proved reserves					
Rocky Mountain Region					
Wattenberg	126,071	17,227	229,433	32	%
Grand Valley (1)	375,379	517	378,481	53	%
NECO	31,463	-	31,463	4	%
Other	361	251	1,867	-	%
Total Rocky Mountain Region	533,274	17,995	641,244	89	%
Appalachian					
Other	60,845	34	61,049	9	%
Other	14,806	41	15,052	2	%
Total proved reserves	608,925	18,070	717,345	100	%

(1)Two leases in our Grand Valley Field represent 53% of our total proved reserves.

Table of Contents

Production, Sales, Prices and Lifting Costs

The following table presents information regarding our production volumes, natural gas and oil sales, average sales price received and average lifting cost.

	Year Ended December 31,		
	2009	2008	2007
Production (1) (2)			
Natural gas (Mcf)	35,536,092	31,759,792	22,513,306
Oil (Bbls)	1,291,488	1,160,408	910,052
Natural gas equivalent (Mcf)	43,285,020	38,722,240	27,973,618
Mcf per day	118,589	106,088	76,640
Natural Gas and Oil Sales (in thousands)			
Natural gas	\$110,735	\$221,734	\$119,991
Oil	71,064	104,168	55,196
Provision for underpayment of natural gas sales	(2,706)	(4,025)	-
Total natural gas and oil sales	\$179,093	\$321,877	\$175,187
Average Sales Price (2)			
Natural gas (per Mcf)	\$3.12	\$6.98	\$5.33
Oil (per Bbl)	\$55.03	\$89.77	\$60.65
Natural gas equivalent (per Mcfe)	\$4.20	\$8.42	\$6.26
Average Lifting Cost (per Mcfe) (2) (3)	\$0.83	\$1.07	\$0.90

(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold or other property interest we own.

(2) See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations – Natural Gas and Oil Sales for amounts per operating area.

(3) Lifting costs represent natural gas and oil lease operating expenses, exclusive of ad valorem and severance taxes, on a per unit basis.

Natural Gas Sales

We sell our natural gas to other gas marketers, utilities, industrial end-users and other wholesale gas purchasers. We generally sell the natural gas that we produce under contracts with indexed monthly pricing provisions. Virtually all of our contracts include provisions wherein prices change monthly with changes in the market, for which certain adjustments may be made based on whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, our revenues from the sale of natural gas are directly proportional, holding production volume constant, to market prices; as market prices decline, so too does our revenues, and as prices increase, our revenues increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry. We also enter into financial derivatives in order to reduce the impact of possible price instability regarding the physical sales market. See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation: Results of Operations – Commodity Price Risk Management, Net, Natural Gas and Oil Derivative Activities and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

In general, we have been and expect to continue to be able to produce and sell natural gas from our wells without significant curtailment and at competitive prices. We do, however, experience limited curtailments from time to time due to pipeline maintenance and operating issues. Open access transportation through the country's interstate pipeline system gives us access to a broad range of markets. Whenever feasible, we obtain access to multiple pipelines and markets from each of our gathering systems seeking the best available market for our natural gas at any point in time.

Table of Contents

Oil Sales

Our wells in the Wattenberg Field produce natural gas as well as oil. As of December 31, 2009, oil represented 15.1% of our total equivalent reserves, and for the year then ended, accounted for approximately 17.9% of our natural gas and oil production and 39.7% of our natural gas and oil sales revenue.

We are currently able to sell all the oil that we can produce under existing sales contracts with petroleum refiners and marketers. We do not refine any of our oil production. Our crude oil production is sold to purchasers at or near our wells under both short and long-term purchase contracts with monthly pricing provisions.

Well Operations

As of December 31, 2009, we had an interest in approximately 5,000 wells. We are paid a monthly operating fee for the portion of each well we operate that is owned by others, including our sponsored partnerships. The fee is competitive with rates charged by other operators in the area. The fee covers monthly operating and accounting costs, insurance and other recurring costs.

Transportation and Gathering

We develop, own and operate gathering systems in some of our areas of operations. We also continue to construct new trunk lines as necessary to provide for the marketing of natural gas being developed from new areas and to enhance or maintain our existing systems. 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 our evaluation of our leasing, development and acquisition opportunities.

Our natural gas and oil are transported through our own and third party gathering systems and pipelines, and we incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third-party processor or transporter. Capacity on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas transporters. While our ability to market our natural gas has been only infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. In order to meet pipeline specifications, we are required, in some cases, to process our gas before we can transport it. We typically contract with third parties in the Grand Valley and NECO areas of our Rocky Mountain Region and Appalachian Basin for firm transportation of our natural gas. We also may enter into firm sales agreements to ensure that we are selling to a purchaser who has contracted for pipeline capacity. These agreements are subject to the same limitations discussed above in this paragraph. See Note 11, Commitments and Contingencies, to our consolidated financial statements included in this report for our long-term firm sales, processing and transportation agreements for pipeline capacity.

Natural Gas Marketing

RNG specializes in the purchase, aggregation and sale of natural gas production in our Eastern operating areas. RNG purchases for resale natural gas produced by third party producers as well as natural gas produced by us, our affiliated partnerships and joint venture. The gas is marketed to third party marketers, natural gas utilities, as well as industrial and commercial customers, either directly through our gathering system, or through transportation services provided by regulated interstate pipeline companies. RNG's employees have extensive knowledge of natural gas markets in our areas of operations. Such knowledge assists us in maximizing our prices as we market natural gas purchased by RNG.

Our industry competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers. A variety of factors affect the market for natural gas, including:

- the availability of other domestic production;
 - natural gas imports;
- the availability and price of alternative fuels;
- the proximity and capacity of natural gas pipelines;
- general fluctuations in the supply and demand for natural gas; and
- the effects of state and federal regulations on natural gas production and sales.

Table of Contents

Commodity Price Risk Management Activities

We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility with regard to our natural gas and oil sales and natural gas marketing. We utilize both financial and physical instruments. The financial instruments generally consist of collars, swaps and basis swaps and are NYMEX-traded and CIG and PEPL-based contracts. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price stability for committed and anticipated natural gas and oil purchases and sales, generally forecasted to occur within the next two to four-year period. Our policies prohibit the use of commodity derivatives for speculative purposes and permit utilization of derivatives only if there is an underlying physical position. We manage price risk on only a portion of our anticipated production, so the remaining portion of our production is subject to the full fluctuation of market pricing.

RNG has extensive experience with the use of derivatives to reduce the risk and effect of natural gas price changes. RNG uses these financial derivatives to coordinate fixed purchases and sales. We use financial derivatives to establish "floors" and "ceilings" or "collars" on the possible range of the prices realized for the sale of natural gas and oil in addition to fixing prices by using swaps. RNG also enters into back-to-back fixed-price purchases and sales contracts with counterparties. These fixed physical contracts meet the definition of a derivative. Both types of derivatives (i.e., the physical deals and the cash settled contracts) are carried on the balance sheets at fair value with changes in fair values recognized currently in the statement of operations.

We are subject to price fluctuations for natural gas sold in the spot market and under market index contracts. RNG does not always hedge the area basis risk for third party trades with back-to-back fixed price purchases and sales. We continue to evaluate the potential for reducing these risks by entering into derivative transactions. In addition, we may close out any portion of derivatives that may exist from time to time which may result in a realized gain or loss on that derivative transaction.

Governmental Regulation

While the prices of natural gas and oil are set by the market, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for natural gas and oil production depends on several factors beyond our control. These factors include regulation of production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas and oil available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of natural gas and oil, to prevent waste of natural gas and oil, to protect rights among owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. In the western part of the U.S., the federal and state governments own a large percentage of the land and the rights to develop natural gas and oil. Generally, government leases are subject to additional regulations and controls not commonly seen on private leases. We take the steps necessary to comply with applicable regulations, both on our own behalf and as part of the services we provide to our drilling partnerships. We believe that we are in compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. The following summary discussion of the regulation of the U.S. oil and natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which our operations may be subject.

Regulation of Natural Gas and Oil Exploration and Production. Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of natural gas and oil, the development, production and marketing of natural gas and oil and environmental and safety matters. Many laws and regulations require drilling

permits and govern the spacing 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 in the state in which the area to be drilled is located. The permits and approvals include those for the drilling of wells. Additionally, other regulated matters include:

- - bond requirements in order to drill or operate wells;
 - the location of wells;
 - the method of drilling and casing wells;
 - the surface use and restoration of well properties;
 - the plugging and abandoning of wells; and
 - the disposal of fluids.

Table of Contents

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 properties. 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 voluntary, it may be more difficult to form units, and therefore, more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from natural gas and oil wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. Where wells are to be drilled on state or federal leases, additional regulations and conditions may apply. The effect of these regulations may limit the amount of natural gas and oil 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 natural gas and oil wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves. As a result, we are unable to predict the future cost or effect of complying with such regulations.

Regulation of Sales and Transportation of Natural Gas. Historically, the price of natural gas was subject to limitation by federal legislation. The Natural Gas Wellhead Decontrol Act removed, as of January 1, 1993, all remaining federal price controls from natural gas sold in "first sales" on or after that date. The Federal Energy Regulatory Commission's, or FERC, jurisdiction over natural gas transportation was unaffected by the Decontrol Act.

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 FERC under the Natural Gas Act of 1938, or 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 its jurisdictional facilities, among other things, are subject to regulation. Each natural gas pipeline company holds certificates of public convenience and necessity issued by the 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 the 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. In the past, FERC has undertaken various initiatives to increase competition within the industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system was substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide transportation separate or "unbundled" from their sales service, and require that pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers. In many

instances, the result of Order No. 636 and related initiatives has been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. Another effect of regulatory restructuring is greater access to transportation on interstate pipelines. In some cases, producers and marketers have benefited from this availability. However, competition among suppliers has greatly increased and traditional long-term producer-pipeline contracts are rare. Furthermore, gathering facilities of interstate pipelines are no longer regulated by FERC, thus allowing gatherers to charge higher gathering 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 less stringent regulatory approach recently pursued 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.

Table of Contents

Environmental Regulations

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and tougher environmental legislation and regulations is expected to continue. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes environmental protection requirements that result in increased costs and reduced access to the industry in general, our business and prospects could be adversely affected.

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or EPA, and various state agencies have limited the approved methods of disposal 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 be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of natural gas and oil. 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, or CERCLA, RCRA and analogous state laws, as well as state laws governing the management of natural gas and oil wastes. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including 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 natural gas and oil wells, we may be liable pursuant to CERCLA and similar state laws.

Our operations may be subject to the Clean Air Act, or CAA, and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain 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 have been developing 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. The State of Colorado has also implemented new air emission regulations in 2009, which affect the industry, including our operations.

The Federal Clean Water Act, or CWA, and analogous state laws impose strict controls against the discharge of pollutants, including spills and leaks of oil and other substances. The CWA also regulates storm water run-off from natural gas and oil facilities and requires a storm water discharge permit for certain activities. Spill prevention,

control, and countermeasure requirements of the CWA require appropriate containment terms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak.

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 oil spills. Federal regulations require certain owners or operators of facilities that store or otherwise handle oil, including us, to procure and implement Spill Prevention, Control and Counter-measures plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990, or OPA, subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages arising from oil spills. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities. We are also subject to the CWA and analogous state laws relating to the control of water pollution, which laws provide varying civil and criminal penalties and liabilities for release of petroleum or its derivatives into surface waters or into the ground. Historically, we have not experienced any significant oil discharge or oil spill problems.

Table of Contents

In 2009, the State of Colorado's Oil and Gas Conservation Commission implemented new broad-based environmental and wildlife protection regulations for the industry. These regulations will increase our costs and may ultimately limit some drilling locations. Our expenses relating to preserving the environment have risen over the past few years and are expected to continue to rise in 2010 and beyond. Environmental regulations have had no materially adverse effect on our operations to date, but 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 – Litigation, Colorado Stormwater Permit, to our consolidated financial statements included 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 natural gas. The occurrence of any of these 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.

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 whether insurance 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 the Rockies Express pipeline; such an event could result in significantly lower regional prices or our inability to deliver gas.

Competition

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 natural gas and oil companies, drilling and income programs and partnerships in all areas of operations, including drilling and marketing natural gas and oil and obtaining desirable natural gas and oil 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 natural gas and oil prospects and to acquire additional properties in the future depends upon our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We also face intense competition in the marketing of natural gas from competitors including other producers as well as marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic natural gas and oil exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future.

During 2008, our industry experienced continued strong demand for drilling services and supplies which resulted in increasing costs. In 2009, due to industry slowdown, we experienced overall reductions in our operating and drilling

costs. Factors affecting competition in the industry include price, location of drilling, availability of drilling prospects and drilling rigs, pipeline capacity, quality of production and volumes produced. We believe that we can compete effectively in the industry in each of the listed areas. Nevertheless, our business, financial condition and results of operations could be materially adversely affected by competition. We also compete with other natural gas and oil companies as well as companies in other industries for the capital we need to conduct our operations. The 2008-2009 turmoil in the capital markets made financing more expensive and difficult to obtain. In the event that we do not have adequate capital to execute our business plan, we may be forced to curtail our drilling and acquisition activities.

Employees

As of December 31, 2009, we had 326 employees, including 200 in production, 7 in natural gas marketing, 25 in exploration and development, 62 in finance, accounting and data processing, and 32 in administration. Our employees are not covered by a collective bargaining agreement. We consider relations with our employees to be very good.

Table of Contents

Our engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and some pipeline systems. In addition, we retain subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites, with our employees supervising the activities of the subcontractors.

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.

Risks Related to the Global Economic Environment

There may be a reoccurrence of the 2009 global economic environment which increased the magnitude and the likelihood of the occurrence of the negative consequences discussed in many of the risks factors that follow.

In particular, consider the risks related to (1) the rapid deterioration of demand for natural gas and oil resulting from the economic environment and the related negative effects on natural gas and oil pricing, and (2) the effect of the credit constraints on our business, including the severe reduction in the availability of credit for drilling or to finance acquisitions. Also consider the interplay between these two risks: decline in natural gas and oil prices can lead to a reduction in the borrowing base for our credit line, and hence a reduction in our credit available for drilling. Similarly, further reductions in natural gas and oil prices could result in some of our assets becoming uneconomic to exploit, which would reduce our reserves, which in turn would reduce our borrowing base and the credit available to us. These factors could result in less drilling and production by us, and could thereby adversely affect our profitability and could limit our ability to execute our business plan. These factors could also make it impossible or extremely expensive to extend the term of our revolving credit line. The global economic environment also increases the potential of counterparty failure risk for both the banks which are parties to our natural gas and oil derivative holdings and for payments from purchasers of our natural gas and oil. Lastly, inability to ascertain the ultimate depth and duration of the economic environment could cause us to refrain from capital expenditures in order to maintain higher liquidity; our uncertainty and caution could result in significantly reduced drilling and hence reduced future production, which in turn may result in reduced reserves, resulting in a reduced borrowing base and availability of funds from our credit facility. All these risks could have a significant adverse effect on our business and our financial results. Any additional deterioration in the domestic or global economic conditions will further amplify these risks.

There may be a reoccurrence of the 2009 disruptions in the global financial markets and the related economic environment may further decrease the demand for natural gas and oil and the prices of natural gas and oil, thereby limiting our future drilling and production, and thereby adversely affecting our profitability.

During much of 2009, prices for natural gas and oil decreased over 60% from the 2008 peak. The well-publicized global financial market disruptions and the related economic environment may further decrease demand for natural gas and oil and therefore lower natural gas and oil prices. If there is such an additional reduction in demand, the continued production of gas may increase current oversupply and result in still lower gas prices. There is no certainty how long this low price environment will continue. We operate in a highly competitive industry, and certain competitors may have lower operating costs in such an environment. Furthermore, as a result of these disruptions in the financial markets, it is possible that in future years we would not be able to borrow or otherwise raise sufficient funds to sustain or increase capital expenditures. Such market conditions may also make it more difficult or impossible for us to finance acquisitions, through either equity or debt; acquisitions have historically been a major source of growth for us. We may also have difficulty finding partners to develop new drilling prospects and to build the pipeline systems needed to transport our gas. Inability of third parties to finance and build additional pipelines out

of the Rockies and elsewhere could cause significant negative pricing effects. Any of the above factors could adversely affect our operating results.

Risks Related to Our Business and the Industry

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

Our revenue, profitability and cash flow depend in large part upon the prices and demand for natural gas and oil. The markets for these commodities are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas and oil prices have a significant effect on our cash flow and on the value of our reserves, which can in turn reduce our borrowing base under our senior credit agreement. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, 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. The prices in much of 2009 have been too low to economically justify many drilling operations, and it is uncertain how long such low pricing shall persist.

Table of Contents

The prices of natural gas and oil are volatile, often fluctuating greatly. Lower natural gas and oil prices may not only reduce our revenues, but also may reduce the amount of natural gas and oil that we can produce economically. As a result, we may have to make substantial additional downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write-down operating assets to fair value, as a non-cash charge to earnings. We assess impairment of capitalized costs of proved natural gas and oil properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which management reasonably estimates such products may be sold. In 2009, we recorded an impairment charge of \$2.8 million related to our undeveloped leasehold acreage in North Dakota, and in 2008, we recorded impairment charges totaling \$12.8 million related to our proved oil and gas properties, primarily related to our properties in the Fort Worth Basin and in North Dakota. There were no impairment charges recorded during 2007. We may incur impairment charges in the future, which could have a material adverse effect on the results of our operations.

A substantial part of our natural gas and oil production is located in the Rocky Mountain Region, making it vulnerable to risks associated with operating primarily in a single geographic area.

Our operations have been focused on the Rocky Mountain Region, 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 natural gas and oil produced from the wells in the region, natural disasters, 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.

Historically, natural gas prices in the Rocky Mountain Region often fell disproportionately when compared to other markets, due in part to continuing constraints in transporting natural gas from producing properties in the region. Because of the concentration of our operations in the Rocky Mountain Region, such price decreases are more likely to have a material adverse effect on our revenue, profitability and cash flow than those of our more geographically diverse competitors. Although current natural gas prices in the Rocky Mountain Region are not steeply discounted to NYMEX, there can be no assurance as to such continuation.

Our estimated natural gas and oil 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.

Natural gas and oil reserve engineering requires subjective estimates of underground accumulations of natural gas and oil and assumptions concerning future natural gas and oil 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 natural gas and oil reserves using pricing, production, cost, tax and other information that we provide. The reserve estimates are based on certain assumptions regarding future natural gas and oil prices, production levels, and operating and development costs that may prove incorrect. Any significant variance from these assumptions to actual figures could greatly affect:

- the estimates of reserves;
- the economically recoverable quantities of natural gas and oil 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 the future net cash flows; and
- timing of our capital expenditures.

Some of our reserve estimates must be made with limited production history, which renders these reserve estimates less reliable than estimates based on a longer production history. Numerous changes over time to the assumptions on which the reserve estimates are based, as described above, often result in the actual quantities of natural gas and oil recovered being different from earlier reserve estimates.

Table of Contents

The present value of our estimated future net cash flows from proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves. As of December 31, 2009, the estimated discounted future net cash flows from proved reserves are based on prior year average prices, and are no longer based on selling prices in effect at year end. However, factors such as actual prices we receive for natural gas and oil and hedging instruments, the amount and timing of actual production, amount and timing of future development costs, supply of and demand for natural gas and oil, and changes in governmental regulations or taxation also affect our actual future net cash flows from our natural gas and oil properties.

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas and oil 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 natural gas and oil properties or the industry in general.

Unless natural gas and oil 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.

Producing natural gas and oil reservoirs generally is characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we estimated and the rate can change due to other circumstances. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income, are highly dependent on efficiently developing and exploiting our current reserves and economically finding or acquiring 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. As a result, our future operations, financial condition and results of operations would be adversely affected.

Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.

Acquisitions of producing properties and undeveloped properties have been an important part of our historical 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 natural gas and oil prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform engineering, geological and geophysical reviews of the acquired properties, which we believe is 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 do 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.

Our focus on acquiring producing natural gas and oil properties may increase our potential exposure to liabilities and costs for environmental and other problems existing on acquired properties. Often we are not entitled to contractual indemnification associated with acquired properties. Normally, we acquire interests in properties on an "as is" basis with no or limited remedies for breaches of representations and warranties, as was the case in the acquisitions of assets from EXCO Resources Inc. and Castle Gas Company, as well as the acquisition of all shares of Unioil, Inc. We could incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, in our acquisitions for which we have limited or no contractual remedies or insurance coverage.

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 be in different geographic locations than our existing properties. For example, in the Castle acquisition, we acquired interests in wells which we will need to operate together with other partners, we acquired pipelines that we will need to operate and expect we will need to commit to drilling in the acquired areas to achieve the expected benefits. Consequently, we may not be able to efficiently realize the assumed or expected economic benefits of properties that we acquire, if at all.

Table of Contents

When drilling prospects, we may not yield natural gas or oil in commercially viable quantities.

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of natural gas or oil bearing rocks. However, our geologists cannot know conclusively prior to drilling and testing whether natural gas or oil will be present or, if present, whether natural gas or oil 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 oil or natural gas, 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 natural gas and oil to be profitable. If we drill a dry hole or unprofitable well on current and future prospects, the profitability of our operations will decline and our value will likely be reduced. In sum, the cost of drilling, completing and operating any well is often uncertain and new wells may not be productive.

We may not be able to identify enough attractive prospects on a timely basis to meet our development needs, which could limit our future development opportunities.

Our geologists have identified a number of potential drilling locations on our existing acreage. These drilling locations must be replaced as they are drilled for us to continue to grow our reserves and production. Our ability to identify and acquire new drilling locations depends on a number of uncertainties, including the availability of capital, regulatory approvals, natural gas and oil prices, competition, costs, availability of drilling rigs, drilling results and the ability of our geologists to successfully identify potentially successful new areas to develop. Because of these uncertainties, our profitability and growth opportunities may be limited by the timely availability of new drilling locations. As a result, our operations and profitability could be adversely affected.

Drilling for and producing natural gas and oil 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 natural gas and oil 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;
- blowouts;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;
- 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. We maintain insurance against various losses and liabilities arising from operations; however, insurance against all operational risks is not available. Additionally, our management may elect not to obtain insurance if the cost of available insurance is excessive relative to the perceived risks presented. Thus, losses could occur for

uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business activities, financial condition and results of operations.

Table of Contents

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 have conducted exploratory drilling and plan to continue exploratory drilling in 2010 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 when they 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 have a negative effect on our debt covenants.

Increasing finding and development costs may impair our profitability.

In order to continue to grow and maintain our profitability, we must annually add new reserves that exceed our yearly production 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 natural gas and oil 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. The acquisition market for natural gas and oil properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values climbed toward historic highs during 2007 and the first half of 2008 on a per unit basis, particularly in the Rocky Mountain Region, and although 2009 pricing multiples were stable these values 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 finding and development costs continues, we will be exposed to an increased likelihood of a write-down in carrying value of our natural gas and oil properties in response to falling commodity prices and reduced profitability of our operations.

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 natural gas and oil reserves, and ultimately our profitability.

The 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 natural gas and oil reserves. To date, we have financed capital expenditures primarily with bank borrowings, cash generated by operations and our 2008 senior note issuance. We intend to finance our future capital expenditures with cash flow from operations, funds from our 2009 sale of equity, capital contributed to our joint venture by our joint venture partner and other existing and planned financing arrangements. Our cash flows from operations and access to capital are subject to a number of variables, including:

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

If our revenues or the borrowing base under our credit facility decreases as a result of lower natural gas and oil prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the

capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas and oil prices, or we incur operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at planned levels, and our profitability may be adversely affected.

If additional capital is needed, we may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by our operations or sale of drilling partnerships or available under our revolving credit facility is not sufficient to meet our capital requirements, failure to obtain additional financing could result in a curtailment of the exploration and development of our prospects, which in turn could lead to a possible loss of properties, decline in natural gas and oil reserves and a decline in our profitability.

Table of Contents

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

Seasonal weather conditions and lease stipulations designed to protect various wildlife affect natural gas and oil operations in the Rocky Mountains. In certain areas, including parts of the Piceance Basin in Colorado, drilling and other natural gas and oil activities are restricted or prohibited by lease stipulations, or prevented by weather conditions, for up to six months out of the year. This limits our operations in those areas and can intensify competition during those 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.

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 most of the wells in which we own an interest. However, there are some wells we do not operate because we participate through joint operating agreements under which we own partial interests in natural gas and oil properties operated by other entities. 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 underlying properties. The failure by an operator to adequately perform operations, or an operator's breach of the applicable agreements, could reduce production and revenues and affect our profitability. 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.

Market conditions or operational impediments could hinder our access to natural gas and oil markets or delay production.

Market conditions or the unavailability of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas and oil markets or delay our production. The availability of a ready market for natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for the lack of a market or because of inadequacy, unavailability or the pricing associated with natural gas pipelines, gathering system capacity or processing facilities. If that were to occur, we would be unable to realize revenue from those wells until we made production arrangements to deliver the product to market. Thus, our profitability would be adversely affected.

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

We use derivatives for a portion of our natural gas and oil production from our own wells, our partnerships and for natural gas purchases and sales by our marketing subsidiary to achieve a more predictable cash flow, to reduce exposure to adverse fluctuations in the prices of natural gas and oil, 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, the counter-party to the derivative contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the derivative agreement and actual prices that we receive.

In addition, derivative arrangements may limit the benefit from changes in the prices for natural gas and oil and 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 if our derivative instruments qualified for hedge accounting. For instance, if natural gas and oil prices rise significantly, it could result in significant non-cash charges each quarter, which could have a material negative effect on our net income.

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

Substantially all of our accounts receivable result from natural gas and oil 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 natural gas and oil derivatives as well as the derivatives used by our marketing subsidiary expose us to credit risk in the event of nonperformance by counterparties.

Table of Contents

Terrorist attacks or similar hostilities may adversely affect our results of operations.

Increasing terrorist attacks around the world have created many economic and political uncertainties, some of which may materially adversely affect our business. Uncertainty surrounding military strikes or a sustained military campaign may affect our operations in unpredictable ways, including disruptions of fuel supplies and markets, particularly oil, and the possibility that infrastructure facilities, including pipelines, production facilities, processing plants and refineries, could be direct targets of, or indirect casualties of, an act of terror or war. The continuation of these attacks may subject our operations to increased risks and, depending on their ultimate magnitude, could have a material adverse effect on our business, results of operations, financial condition and prospects.

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 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. For some risks, such as drilling blow-out insurance, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks that we are subject to are generally not fully insurable.

We may not be able to keep pace with technological developments in our industry.

The industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. 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 new technologies at substantial cost. In addition, other natural gas and oil companies 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 the industry is intense, which may adversely affect our ability to succeed.

The industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce natural gas and oil, 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 natural gas and oil properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil market prices. Larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which can adversely affect our competitive position. 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, because many companies in our industry have greater financial and human resources, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties. These factors could adversely affect the success of our operations and our profitability.

The current trend is to increase regulation of our operations and 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 to plan, design, drill, install, operate and abandon natural gas and oil wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

Table of Contents

Part of the regulatory environment includes federal requirements for obtaining environmental assessments, environmental impact studies and/or plans of development before commencing exploration and production activities. In addition, our activities are subject to the regulation of conservation practices 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 natural gas and oil that we can produce and market. A major risk inherent in our drilling plans is the need to obtain drilling permits from state and local authorities. Delays in obtaining regulatory approvals, 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 on or develop our properties. Additionally, the natural gas and oil regulatory environment could change in ways that might substantially increase our financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability. Furthermore, these additional costs may put us at a competitive disadvantage compared to larger companies in the industry which can spread such additional costs over a greater number of wells and larger operating staff.

Illustrative of this trend are the regulations implemented in 2009 by the State of Colorado, which focus on the industry. These multi-faceted regulations significantly enhance requirements regarding natural gas and oil permitting, environmental requirements and wildlife protection. Permitting delays and increased costs could result from these final regulations.

Other potential laws and regulations affecting us include the following:

- State and federal initiatives to further regulate hydraulic fracturing, including the so-called "Frac Act," which would amend the Federal Drinking Water Act, if adopted, would require disclosure of chemicals used in fracturing as well as other restrictions, which could lead to operational delays and increased costs.
- The 2011 federal budget, as initially proposed, contains several provisions harmful to the oil and gas industry; most importantly it would limit our ability to deduct intangible drilling costs in the year incurred, as provided under current law. This could have an adverse financial effect on us and on the economic viability of any future drilling.
- Several bills in Congress, if passed, would establish a "cap and trade" system regarding greenhouse gas emissions. Companies would be assigned emission "allowances" under these bills which would decline each year. In addition, new EPA greenhouse gas monitoring and reporting regulations may affect us and the third parties that process our oil and natural gas.
- Several federal regulatory proposals, if they became law, would limit the use of over-the-counter (OTC) derivatives, including the oil and gas price hedging we currently use. Limits on the use of OTC instruments could impair our use of these derivatives and could limit our ability to protect our cash flows and reduce oil and gas price risk.
- New or increased severance taxes have been proposed in several states, including Pennsylvania. This could adversely affect the existing operations in these states and the economic viability of future drilling.

Litigation has been commenced against us pertaining to our royalty practices and payments; the cost of our defending these lawsuits, and any future similar lawsuit, could be significant and any resulting judgments against us could have a material adverse effect upon our financial condition.

In recent years, litigation has commenced against us and several other companies in our industry regarding royalty practices and payments in jurisdictions where we conduct business. For more information on the suits that currently relate to us, see Note 11, Commitments and Contingencies, to our consolidated financial statements included in this report. We intend to defend ourselves vigorously in these cases. Even if the ultimate outcome of this litigation resulted in our dismissal, defense costs could be significant. 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. Although we cannot predict an eventual outcome of this litigation, a judgment in favor of a plaintiff could have a material adverse effect on our financial condition or profitability.

Any future failure to maintain effective internal control over financial reporting and/or effective disclosure controls and procedures could have a material adverse effect on the reliability of our financial statements and our ability to file public reports on time, raise capital and meet our debt obligations.

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008 and 2009, and pursuant to those assessments, concluded that we did maintain effective internal control over financial reporting as of December 31, 2008 and 2009. However, as of December 31, 2007, management's assessment of the effectiveness of our internal control over financial reporting identified two material weaknesses as disclosed in our Annual Report on Form 10-K for the year then ended and filed with the SEC on March 20, 2008. The existence of a material weakness means there is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

Table of Contents

Any future failure to maintain effective internal control over financial reporting and/or effective disclosure controls and procedures could prevent us from being able to prevent fraud and/or provide reliable financial statements and other public reports. Such circumstances could harm our business and operating results, cause investors to lose confidence in the accuracy and completeness of our financial statements and reports, and have a material adverse effect on the trading price of our debt and equity securities and our ability to raise capital necessary for our operations. These failures may also adversely affect our ability to file our periodic reports with the SEC on time. Being late in filing our periodic reports with the SEC may result in the delisting of our common stock from the NASDAQ Stock Market or a default under our senior credit agreement, the indenture governing our outstanding 12% senior notes due 2018, and any other instruments governing debt that we may incur in the future. Ultimately, such defaults could lead to the acceleration of our debt obligations, and if an acceleration of our debt obligations were to occur, we may not have sufficient funds to repay those obligations immediately, and we would be forced to seek alternative repayment arrangements either through a bankruptcy or an out of court debt restructuring. Consequently, a future material weakness could lead to significant and negative changes to our financial condition and the value of our equity and debt securities.

Risks Associated with Our Indebtedness

Our credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations. Our lenders can unilaterally reduce our borrowing availability based on anticipated sustained natural gas and oil prices.

We depend on our revolving credit facility for future capital needs. The terms of the borrowing 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 financing could result in a default under those facilities, 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 natural gas and oil 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 natural gas and oil 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 credit facility could adversely affect our operations and our financial results.

The indenture governing our outstanding senior notes and our senior credit agreement impose (and we anticipate that the indentures governing any other debt securities we may issue will also impose) restrictions on us that may limit the discretion of management in operating our business. That, in turn, could impair our ability to meet our obligations.

The indenture governing our outstanding senior notes and our senior credit agreement contain (and we anticipate that the indentures governing any other debt securities we may issue will also contain) various restrictive covenants that limit management's discretion in operating our business. In particular, these covenants limit our ability to, among other things:

- incur additional debt;
- make certain investments or pay dividends or distributions on our capital stock, or purchase, redeem or retire capital stock;

- sell assets, including capital stock of our restricted subsidiaries;
- restrict dividends or other payments by restricted subsidiaries;
- create liens;
- enter into transactions with affiliates; and
- merge or consolidate with another company.

These covenants could materially and adversely affect our ability to finance our future operations or capital needs. Furthermore, they may restrict our ability to expand, to pursue our business strategies and otherwise conduct our business. Our ability to comply with these covenants may be affected by circumstances and events beyond our control, such as prevailing economic conditions and changes in regulations, and we cannot assure you that we will be able to comply with them. A breach of any of these covenants could result in a default under the indenture governing our outstanding senior notes and any other debt securities we may issue in the future and/or our senior credit agreement. If there were an event of default under our indenture and/or the senior credit agreement, the affected creditors could cause all amounts borrowed under these instruments to be due and payable immediately. Additionally, if we fail to repay indebtedness under our senior credit agreement when it becomes due, the lenders under the senior credit agreement could proceed against the assets which we have pledged to them as security. Our assets and cash flow might not be sufficient to repay our outstanding debt in the event of a default. The occurrence of such an event would adversely affect our operations and profitability.

Table of Contents

Our senior credit agreement also requires us to maintain specified financial ratios and satisfy certain financial tests. Our ability to maintain or meet such financial ratios and tests may be affected by events beyond our control, including changes in general economic and business conditions, and we cannot assure you that we will maintain or meet such ratios and tests, or that the lenders under the senior credit agreement will waive any failure to meet such ratios or tests.

In addition, upon a change in control, we are required to offer to buy each senior note for 101% of the principal amount, plus unpaid interest. A change in control is defined to include: (i) when a majority of the Board of Directors are not continuing directors; (ii) when one person (or group of related persons) holds direct or indirect ownership of over 50% of our voting stock; or (iii) upon sale, transfer or lease of substantially all of our assets.

We may incur additional indebtedness to facilitate our acquisition of additional properties, which would increase our leverage and could negatively affect our business or financial condition.

Our business strategy includes the acquisition of additional properties that we believe would have a positive effect on our current business and operations. We expect to continue to pursue acquisitions of such properties and may incur additional indebtedness to finance the acquisitions. Our incurrence of additional indebtedness would increase our leverage and our interest expense, which could have a negative effect on our business or financial condition.

If we fail to obtain additional financing, we may be unable to refinance our existing debt, expand our current operations or acquire new businesses. This could result in our failure to grow in accordance with our plans, or could result in defaults in our obligations under our senior credit agreement or the indenture relating to our outstanding senior notes.

In order to refinance indebtedness, expand existing operations and acquire additional businesses or properties, we will require substantial amounts of capital. There can be no assurance that financing, whether from equity or debt financings or other sources, will be available or, if available, will be on terms satisfactory to us. If we are unable to obtain such financing, we will be unable to acquire additional businesses or properties and may be unable to meet our obligations under our senior credit agreement and the indenture relating to our outstanding senior notes or any other debt securities we may issue in the future. Such an event would adversely affect our operations and profitability.

Risks Associated with Our Joint Venture

The PDC Mountaineer LLC joint venture is dependent upon our equity partner (the “Investor”) and poses exit-related risks for us.

The board of managers of the joint venture consists of three representatives appointed by us and three representatives appointed by the Investor, 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 the Investor 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 the best interests of the joint venture. 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, the Investor 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 their ownership interests to a third party. The Investor is entitled 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.

After a “restricted period” which generally lasts for the four year years following the closing of the joint venture, the Investor can 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 the Investor’s ownership interests, the Investor 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 the Investor’s interest under the rights of first offer and refusal, 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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

26

Table of Contents

ITEM 2. PROPERTIES

Information regarding our wells, production, proved reserves and acreage are included in Item 1 – Business and in Note 2, Summary of Significant Accounting Policies, to our consolidated financial statements included in this report.

Substantially all of our natural gas and oil properties, exclusive of our joint venture properties, have been mortgaged or pledged as security for our credit facility. Substantially all of our joint venture properties have, however, been pledged as collateral for the joint venture's derivative instruments. See Note 4, Derivative Financial Instruments, and Note 8, Long Term Debt, to our consolidated financial statements included in this report.

Facilities

We lease 26,480 square feet in downtown Denver, Colorado, which serves as our corporate offices, through September 2015. We own a 32,000 square feet administrative office building located in Bridgeport, West Virginia where we also lease approximately 5,000 and 17,700 square feet of office space in two additional buildings through March 2010 and October 2011, respectively.

We own or lease field operating facilities in the following locations:

- West Virginia: Bridgeport and Glenville
- Michigan: Ossineke
- Colorado: Evans, Parachute and Wray
- Pennsylvania: Indiana and Mahaffey

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 in this report.

ITEM 4. [RESERVED]

PART II

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

Our authorized capital stock consists of 100,000,000 shares of common stock, par value \$0.01 per share. Our common stock is traded on the NASDAQ Global Select Market under the ticker symbol PETD. The following table presents 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, 2008	\$ 73.92	\$ 50.75
April 1 - June 30, 2008	79.09	66.37
July 1 - September 30, 2008	68.76	34.15
	44.75	11.50

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

October 1 - December 31, 2008		
January 1 - March 31, 2009	27.91	9.39
April 1 - June 30, 2009	20.63	11.21
July 1 - September 30, 2009	19.14	12.50
October 1 - December 31, 2009	21.87	16.06

As of February 16, 2010, we had approximately 1,076 shareholders of record.

We have not paid any dividends on our common stock and currently intend to retain earnings for use in our business. We do not expect to declare cash dividends in the foreseeable future.

Table of Contents

The following table presents information about our purchases of our common stock during the three months ended December 31, 2009.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 - 31, 2009	796	\$ 17.59	-	-
November 1-30, 2009	2,029	18.06	-	-
December 1-31, 2009	329	18.21	-	-
Total fourth quarter purchases	3,154	17.95		

(1) Purchases represent shares purchased pursuant to our stock-based compensation plans for payment of tax liabilities related to the vesting of securities and shares purchased pursuant to our non-employee director deferred compensation plan.

SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2009, with the cumulative total returns for the same period for the Standard Industrial Code ("SIC") Index, and the Standard and Poor's ("S&P") 500 Index. The SIC Index is a weighted composite of 386 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, 2004, 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.

	Year Ended December 31,					
	2004	2005	2006	2007	2008	2009
Petroleum Development Corporation	\$ 100.00	\$ 86.44	\$ 111.62	\$ 153.31	\$ 62.41	\$ 47.21
S&P 500 Index	100.00	104.91	121.48	128.16	80.74	102.11
SIC Index	100.00	143.67	186.81	262.61	153.66	206.42

Table of Contents

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2009	2008	2007	2006	2005
	(in thousands, except per share data)				
Revenues:					
Natural gas and oil sales	\$179,093	\$321,877	\$175,187	\$115,189	\$102,559
Sales from natural gas marketing	64,635	140,263	103,624	131,325	121,104
Commodity price risk management gain (loss), net (1)	(10,053)	127,838	2,756	9,147	(9,368)
Well operations, pipeline income and other	11,043	11,767	10,170	11,576	9,198
Total revenues	244,718	601,745	291,737	267,237	223,493
Costs and expenses:					
Natural gas and oil production and well operations costs	64,746	79,354	49,833	29,981	21,090
Cost of natural gas marketing	62,534	139,234	100,584	130,150	119,644
Exploration expense and impairment of natural gas and oil properties	22,887	45,105	23,551	8,131	11,115
General and administrative expense	53,985	37,715	30,968	19,047	6,960
Depreciation, depletion and amortization	131,004	104,640	70,885	33,735	21,116
Total costs and expenses	335,156	406,048	275,821	221,044	179,925
Gain on sale of leaseholds (2)	470	-	33,291	328,000	7,669
Income (loss) from operations	(89,968)	195,697	49,207	374,193	51,237
Interest income	254	591	2,662	8,050	898
Interest expense	(37,208)	(28,132)	(9,279)	(2,443)	(217)
Income (loss) from continuing operations before income taxes	(126,922)	168,156	42,590	379,800	51,918
Provision (benefit) for income taxes	(45,716)	59,089	16,505	146,698	19,373
Income (loss) from continuing operations	(81,206)	109,067	26,085	233,102	32,545
Income from discontinued operations, net of tax (3)	113	4,177	7,083	4,670	8,907
Net income (loss)	(81,093)	113,244	33,168	237,772	41,452
Less: net loss attributable to noncontrolling interests	(1,816)	(65)	(41)	-	-
Net income (loss) attributable to shareholders	\$(79,277)	\$113,309	\$33,209	\$237,772	\$41,452
Amounts attributable to Petroleum Development Corporation shareholders:					
Income (loss) from continuing operations	\$(79,390)	\$109,132	\$26,126	\$233,102	\$32,545
Income from discontinued operations, net of tax	113	4,177	7,083	4,670	8,907
Net income (loss) attributable to shareholders	\$(79,277)	\$113,309	\$33,209	\$237,772	\$41,452

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Earnings (loss) per share attributable to shareholders:

Basic					
Income (loss) from continuing operations	\$(4.83) \$7.41	\$1.77	\$14.88	\$1.99
Income from discontinued operations	0.01	0.28	0.48	0.30	0.54
Net income (loss) attributable to shareholders	\$(4.82) \$7.69	\$2.25	\$15.18	\$2.53
Diluted					
Income (loss) from continuing operations	\$(4.83) \$7.35	\$1.76	\$14.81	\$1.98
Income from discontinued operations	0.01	0.28	0.48	0.30	0.54
Net income (loss) attributable to shareholders	\$(4.82) \$7.63	\$2.24	\$15.11	\$2.52

	As of December 31,				
	2009	2008	2007	2006	2005
	(in thousands)				
Total assets	\$1,250,327	\$1,402,704	\$1,050,479	\$884,287	\$444,361
Working capital (deficit)	\$32,936	\$31,266	\$(50,212) \$29,180	\$(16,763
Long-term debt	\$280,657	\$394,867	\$235,000	\$117,000	\$24,000
Equity	\$538,593	\$512,275	\$396,285	\$360,144	\$188,265

- (1) See Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.
- (2) In July 2006, we sold a portion of our undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. See Note 17, Sale of Natural Gas and Oil Properties, to our consolidated financial statements included in this report.
- (3) See Note 16, Discontinued Operations, to our consolidated financial statements included in this report.

Table of Contents

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 in this report. Further, we encourage you to revisit Special Note Regarding Forward-Looking Statements on page 1 of this report.

Non-GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) attributable to shareholders" and "adjusted EBITDA," non-GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons and providing public guidance on possible future results. These measures are not measures of financial performance under GAAP and should be considered in addition to, not as a substitute for, cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP. The non-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-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-GAAP Financial Measures below for a detailed description of these measures as well as a reconciliation of each to the nearest GAAP measure.

2009 Overview

Even with natural gas prices rebounding somewhat in the last two months of 2009 from earlier in the year, overall we experienced depressed natural gas prices during 2009 compared to 2008. As our production increased to 43.3 Bcfe for 2009 compared to 38.7 Bcfe for 2008, an increase of 11.8%, primarily due to drilling programs in 2007 and 2008, our average sales price declined 50.1% or \$4.22 per Mcfe. While the significant changes in commodity prices have impacted our results of operations, we believe that we were successful in managing our operations to reduce the negative impacts through our derivative positions. Our realized derivative gains for 2009 of \$107.3 million added an average of \$2.48 per Mcfe produced during 2009.

These realized derivative gains were the key component in our ability to increase our operating cash flow by \$4.8 million to \$143.9 million for 2009 as compared to 2008. With our strong operating cash flows, proceeds from our equity offering, and the formation of our joint venture, which allowed us to monetize a portion of our Appalachian Basin assets, we were able to pay down our debt and improve our liquidity position during the global recession of 2009. This allows us flexibility and stability as we enter 2010.

Table of Contents

Results of Operations

Summary Operating Results

The following table presents selected information regarding our results of operations.

	Year Ended December 31,			Change			
	2009	2008	2007	2009-2008	2008-2007		
(dollars in thousands, except per unit data)							
Production (1)							
Natural gas (Mcf)	35,536,092	31,759,792	22,513,306	11.9	%	41.1	%
Oil (Bbls)	1,291,488	1,160,408	910,052	11.3	%	27.5	%
Natural gas equivalent (Mcf) (2)	43,285,020	38,722,240	27,973,618	11.8	%	38.4	%
Mcf per day	118,589	106,088	76,640				
Natural Gas and Oil Sales							
Natural gas	\$110,735	\$221,734	\$119,991	-50.1	%	84.8	%
Oil	71,064	104,168	55,196	-31.8	%	88.7	%
Provision for underpayment of natural gas sales	(2,706)	(4,025)	-	32.8	%	*	
Total oil and natural gas sales	\$179,093	\$321,877	\$175,187	-44.4	%	83.7	%
Realized Gain on Derivatives, net (3)							
Natural gas	\$89,464	\$12,632	\$7,350	*		71.9	%
Oil	17,881	(3,145)	(177)	*		*	
Total realized gain on derivatives, net	\$107,345	\$9,487	\$7,173	*		32.3	%
Average Sales Price (excluding gain/loss on derivatives)							
Natural gas (per Mcf)	\$3.12	\$6.98	\$5.33	-55.3	%	31.0	%
Oil (per Bbl)	\$55.03	\$89.77	\$60.65	-38.7	%	48.0	%
Natural gas equivalent (per Mcfe)	\$4.20	\$8.42	\$6.26	-50.1	%	34.5	%
Average Sales Price (including gain/loss on derivatives)							
Natural gas (per Mcf)	\$5.63	\$7.38	\$5.66	-23.7	%	30.5	%
Oil (per Bbl)	\$68.87	\$87.06	\$60.46	-20.9	%	44.0	%
Natural gas equivalent (per Mcfe)	\$6.68	\$8.66	\$6.52	-22.9	%	32.9	%
Average Lifting Cost (per Mcfe) (4)							
	\$0.83	\$1.07	\$0.90	-22.4	%	18.9	%
Natural Gas Marketing (5)							
	\$2,101	\$1,029	\$3,040	104.2	%	-66.2	%
Other Costs and Expenses							
Exploration expense and impairment of natural gas and oil properties	\$22,887	\$45,105	\$23,551	-49.3	%	91.5	%
General and administrative expense	\$53,985	\$37,715	\$30,968	43.1	%	21.8	%
Depreciation, depletion and amortization	\$131,004	\$104,640	\$70,885	25.2	%	47.6	%

Interest Expense	\$37,208	\$28,132	\$9,279	32.3	%	203.2	%
------------------	----------	----------	---------	------	---	-------	---

* Percentage change not meaningful or equal to or greater than 250%

-
- (1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage of the leasehold or other property interest we own.
 - (2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one Bbl of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.
 - (3) We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility of our natural gas and oil sales. These amounts represent realized derivative gains and losses related to natural gas and oil sales, which do not include realized derivative gains and losses related to natural gas marketing.
 - (4) Lifting costs represent natural gas and oil lease operating expenses, exclusive of production taxes, on a per unit basis.
 - (5) Represents sales from natural gas marketing, net of costs of natural gas marketing.

Table of Contents

Natural Gas and Oil Sales

The following tables present natural gas and oil production and average sales price by area.

	Year Ended December 31,			Change		
	2009	2008	2007	2009-2008	2008-2007	
Production						
Natural gas (Mcf)						
Rocky Mountain Region	29,987,465	26,136,487	18,123,851	14.7	% 44.2	%
Appalachian Basin	4,010,511	3,902,183	2,711,300	2.8	% 43.9	%
Other	1,538,116	1,721,122	1,678,155	-10.6	% 2.6	%
Total	35,536,092	31,759,792	22,513,306	11.9	% 41.1	%
Oil (Bbls)						
Rocky Mountain Region	1,277,887	1,149,071	900,261	11.2	% 27.6	%
Appalachian Basin	9,589	6,623	5,490	44.8	% 20.6	%
Other	4,012	4,714	4,301	-14.9	% 9.6	%
Total	1,291,488	1,160,408	910,052	11.3	% 27.5	%
Natural gas equivalent (Mcf)						
Rocky Mountain Region	37,654,787	33,030,913	23,525,417	14.0	% 40.4	%
Appalachian Basin	4,068,045	3,941,921	2,744,240	3.2	% 43.6	%
Other	1,562,188	1,749,406	1,703,961	-10.7	% 2.7	%
Total	43,285,020	38,722,240	27,973,618	11.8	% 38.4	%

	Year Ended December 31,			Change		
	2009	2008	2007	2009-2008	2008-2007	
Average Sales Price (excluding gain/loss on derivatives)						
Natural gas (per Mcf)						
Rocky Mountain Region	\$2.98	\$6.57	\$5.01	-54.6	% 31.1	%
Appalachian Basin	4.00	9.21	6.99	-56.6	% 31.8	%
Other	3.47	8.41	6.12	-58.7	% 37.4	%
Weighted average price	3.12	6.98	5.33	-55.3	% 31.0	%
Oil (per Bbl)						
Rocky Mountain Region	\$55.01	\$89.73	\$60.62	-38.7	% 48.0	%
Appalachian Basin	57.24	88.80	59.08	-35.5	% 50.3	%
Other	55.36	100.79	68.31	-45.1	% 47.5	%
Weighted average price	55.03	89.77	60.65	-38.7	% 48.0	%
Natural gas equivalent (per Mcfe)						
Rocky Mountain Region	\$4.24	\$8.32	\$6.18	-49.0	% 34.6	%
Appalachian Basin	4.05	9.24	7.02	-56.2	% 31.6	%
Other	3.53	8.52	6.20	-58.6	% 37.4	%
Weighted average price	4.20	8.42	6.26	-50.1	% 34.5	%

Although production increased in 2009, natural gas and oil sales revenue, excluding the provision for underpayment of gas sales, decreased \$144.1 million compared to 2008. Contributing to this decrease was \$163.3 million related to decreased natural gas and oil pricing in 2009 as compared to 2008, which was partially offset by a \$19.2 million

increase in production. The production increase of 11.8% for 2009, compared to 2008, was primarily due to our significant capital investment in 2008. Directly attributable to our decision to reduce our capital expenditures for new wells drilled, our production exit rate of 107 MMcfe/day at December 31, 2009, was lower than the 122 MMcfe/day at December 31, 2008. The effects of the decrease in natural gas and oil sales revenue was significantly reduced by realized derivative gains for 2009 of \$107.3 million. See Commodity Price Risk Management, Net discussion below.

The increase in natural gas and oil sales revenue of \$150.7 from 2007 to 2008, excluding the provision for underpayment of gas sales, was a result of a 38.4% increase in production and a 34.5% increase in average commodity sales prices. The increase in production which contributed \$90.5 million of the increase was a result of the significant number of wells drilled in 2008 along with an October 2007 acquisition of oil and gas properties. The increase in average commodity sales prices contributed \$60.2 million to the increase in natural gas and oil sales revenues from 2007 to 2008.

Table of Contents

Natural Gas and Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas and oil and our ability to market our production effectively. Natural gas and oil prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas prices vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets has resulted in a local market oversupply situation from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Oil pricing is driven predominantly by global supply and demand relationships.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes gas sold at CIG prices as well as gas sold at Mid-Continent or other nearby region prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX-based. This negative differential has narrowed in recent months and for two out of the last four months become a slight positive differential, which contradicts historical variances.

The table below presents the pricing basis or market for our natural gas and oil sales based on production for 2009. The pricing basis is the index that most closely relates to the price under which our natural gas and oil is sold.

Energy Market Exposure as of December 31, 2009			
Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Piceance/Wattenberg	CIG	Gas	41%
Colorado/North Dakota	NYMEX	Oil	18%
	San Juan Basin/Southern		
Piceance	California	Gas	15%
Appalachian	NYMEX	Gas	10%
	Mid Continent (Panhandle		
NECO	Eastern)	Gas	7%
Michigan	Mich-Con/NYMEX	Gas	4%
Wattenberg	Colorado Liquids	Gas	4%
Other	Other	Gas/Oil	1%
			100%

Natural Gas and Oil Production and Well Operations Costs. Natural gas and oil production and well operations costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines for our affiliated partnerships and other third parties (whose income is included in well operations, pipeline income, and other) and certain production and engineering staff related overhead costs.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Lease operating expense	\$35,965	\$41,351	\$25,210
Production taxes	9,262	18,740	12,252

Costs of well operations and pipeline income	6,923	5,694	5,126
Overhead and other production expenses	12,596	13,569	7,245
Total natural gas and oil production and well operations costs	\$64,746	\$79,354	\$49,833

Lease Operating Expense. Lifting costs per Mcfe decreased 22.4% to \$0.83 per Mcfe for 2009 from \$1.07 per Mcfe for 2008. The decrease per Mcfe is primarily due to lower third party costs from service providers as a result of pressure by us to reduce costs as natural gas and oil prices deteriorated, our own cost reduction initiatives, and increased production, which allows us to spread the fixed portion of our production costs over the increased volume. Lifting cost per Mcfe increased 18.9% in 2008 from \$0.90 per Mcfe in 2007. The increase was primarily due to general oil field services and wage inflation pressures in the high commodity sales pricing environment during 2008.

Table of Contents

Production Taxes. Production taxes decreased \$9.5 million or 50.6% to \$9.3 million in 2009 compared to 2008. Production taxes fluctuate with natural gas and oil sales. The decrease in 2009 is the result of the 44.4% decrease in natural gas and oil sales from 2008. The 2008 increase in production taxes of \$6.5 million corresponds with the 83.7% increase in natural gas and oil sales from those in 2007.

Cost of well operations and pipeline income. The increases in cost of well operations and pipeline income for 2009 compared to 2008 were the result of costs related to pipeline maintenance projects offset in part by lower field services costs.

Overhead and other production expenses. Overhead and other production expenses decreased in 2009 compared to 2008 due to the lower cost of field services, including vehicles, lower rates from third parties and less work and services being performed in this low commodity price environment, offset in part by a \$2.7 million accrual for firm transportation costs in the Piceance Basin based on a projected shortfall in minimum volume requirements. The increase from 2007 to 2008 of \$6.3 million was due to significantly increased production, additional personnel in the production and engineering staffs, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers and significant general oil field services inflation pressures.

Commodity Price Risk Management, Net

Commodity price risk management, net includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our natural gas and oil production. Commodity price risk management, net does not include derivative transactions related to natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report for additional details of our derivative financial instruments.

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Commodity price risk management gain (loss), net:			
Realized gains (losses):			
Natural gas	\$89,464	\$12,632	\$7,350
Oil	17,881	(3,145)	(177)
Total realized gains (losses), net	107,345	9,487	7,173
Unrealized gains (losses):			
Reclassification of realized (gains) losses included in prior periods unrealized	(84,655)	549	(4,843)
Unrealized gains (losses) for the period	(32,743)	117,802	426
Total unrealized gains (losses), net	(117,398)	118,351	(4,417)
Total commodity price risk management gain (loss), net	\$(10,053)	\$127,838	\$2,756

Realized gains recognized in 2009 of \$107.3 million are a result of lower natural gas and oil spot prices at settlement compared to the respective strike price. During 2009, we recorded unrealized losses on our CIG basis swaps of \$33.9 million as the forward basis differential between NYMEX and CIG had continued to narrow along with unrealized losses of \$15 million on our oil positions, offset by unrealized gains of \$16.2 million on our natural gas positions.

During the first half of 2008, we experienced both realized and unrealized derivative losses as natural gas and oil prices were at or near record prices. During the second half of the year, due to the tumbling commodity prices, we had both significant realized and unrealized derivative gains. We ended the year with a net realized and unrealized derivative gain of \$127.8 million. The unrealized gain includes a gain on our natural gas and oil positions of \$120.5 million and an unrealized loss on our CIG basis swaps of \$2.7 million.

Table of Contents

Natural Gas and Oil Sales Derivative Instruments. We use various derivative instruments to manage fluctuations in natural gas and oil prices. We have in place a variety of collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and oil production. Under our collar arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor price, the counterparty pays us. Under our commodity swap arrangements, if the applicable index rises above the swap price, we pay the counterparty; however, if the index drops below the swap price, the counterparty pays us. Under our basis protection swaps, if the differential widens beyond the basis swap price, then the counterparty pays us; however, if the differential narrows, then we pay the counterparty. Because we sell all of our physical natural gas and oil at similar prices to the indexes inherent in our derivative instruments, we ultimately realize a price related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price related to our swaps.

The following table presents our derivative positions (excluding the derivative positions designated to our affiliated partnerships) related to natural gas and oil sales in effect as of December 31, 2009, on our production by area. Our production volumes for the fourth quarter of 2009 were 292,190 Bbls of oil and 8.2 Bcf of natural gas.

Commodity/Operating Area/Index	Collars		Fixed-Price Swaps		CIG Basis Protection Swaps		Fair Value At December 31, 2009 (in thousands)	
	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price		Quantity (Gas-MMBtu Oil-Bbls)	Average Contract Price	Weighted Average Contract Price		
		Floors	Ceilings			Oil-Bbls)		Price
Natural Gas								
Rocky Mountain Region								
CIG								
1Q 2010	2,167,137	\$7.50	\$7.50	1,515,805	\$9.20	-	\$-	\$10,540
4Q 2010	680,250	4.75	9.45	-	-	-	-	122
2011	1,020,375	4.75	9.45	959,743	5.81	-	-	161
PEPL								
1Q 2010	510,000	9.00	14.00	360,000	10.91	-	-	3,743
2Q 2010	300,000	5.00	8.90	300,000	6.49	-	-	482
3Q 2010	300,000	5.00	8.90	300,000	6.49	-	-	405
4Q 2010	360,000	5.55	9.38	296,260	6.28	-	-	307
2011	390,000	5.76	9.56	2,117,424	6.18	-	-	638
2012 - 2013	-	-	-	2,346,224	6.18	-	-	(76)
NYMEX								
1Q 2010	562,725	10.00	17.15	375,510	8.98	-	-	3,706
2Q 2010	152,202	5.85	10.15	3,055,239	6.01	2,636,837	(1.88)	(2,277)
3Q 2010	152,202	5.85	10.15	2,968,502	6.02	2,541,588	(1.88)	(2,835)
4Q 2010	568,990	5.94	9.15	1,757,987	6.66	1,793,953	(1.88)	(1,295)
2011	724,478	5.96	9.10	7,703,191	6.96	7,668,501	(1.88)	(4,471)
2012 - 2013	8,785,102	6.05	8.43	7,406,878	7.08	14,610,818	(1.88)	(11,167)

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Appalachia

NYMEX

1Q 2010	21,128	10.00	17.15	703,960	5.31	-	-	(138)
2Q 2010	7,115	5.85	10.15	687,401	5.32	-	-	(155)
3Q 2010	7,115	5.85	10.15	662,401	5.32	-	-	(278)
4Q 2010	7,190	6.45	11.48	648,933	5.33	-	-	(568)
2011	8,383	6.61	11.60	2,401,807	6.35	-	-	46
2012 - 2013	-	-	-	71,454	7.24	-	-	43

Michigan

NYMEX

1Q 2010	264,996	10.00	17.15	49,688	9.89	-	-	1,366
2Q 2010	73,255	5.85	10.15	72,886	8.55	-	-	276
3Q 2010	73,255	5.85	10.15	72,886	8.55	-	-	261
4Q 2010	73,174	6.45	11.47	60,169	9.17	-	-	253
2011	83,766	6.62	11.64	688,549	7.59	-	-	970
2012 - 2013	427,363	6.05	8.43	1,076,266	7.17	-	-	695

Total Natural Gas	17,720,200			38,659,162		29,251,697		754
-------------------	------------	--	--	------------	--	------------	--	-----

Table of Contents

Commodity/Operating Area/Index	Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		Fair Value At December 31, 2009 (in thousands)
	Quantity (Gas-MMBtu Oil-Bbls)	Weighted Average Contract Price Floors	Average Contract Price Ceilings	Quantity (Gas-MMBtu Oil-Bbls)	Average Contract Price	Quantity (Gas-MMBtu Oil-Bbls)	Average Contract Price	
Oil								
Rocky Mountain Region								
NYMEX								
1Q 2010	-	-	-	187,598	89.58	-	-	1,768
2Q 2010	-	-	-	171,187	90.42	-	-	1,484
3Q 2010	-	-	-	155,178	91.42	-	-	1,294
4Q 2010	-	-	-	142,052	92.30	-	-	1,141
2011	231,452	73.00	99.80	355,869	73.89	-	-	(4,721)
2012 - 2013	686,148	75.00	102.63	-	-	-	-	(1,316)
Total Oil	917,600			1,011,885		-	-	(350)
Total Natural Gas and Oil								\$ 404

Natural Gas Marketing

The decrease in sales from natural gas marketing in 2009 compared to 2008 is primarily due to a decrease in prices and increased unrealized losses on derivative instruments, offset by an increase in realized gains on derivatives. In 2009, prices on sales were 54.9% lower on average than in 2008, resulting in a \$107.7 million decrease in sales. In 2009, unrealized derivative gains on sales contracts decreased \$8.1 million from \$4.6 million in 2008 to a loss of \$3.5 million in 2009. This unrealized loss was partially offset by an increase in realized gains of \$7.6 million. Volumes sold decreased by 2% in 2009 compared to 2008, resulting in a \$3.7 million decrease in sales.

The decrease in sales from natural gas marketing in 2009 compared to 2008 is primarily due to a decrease in prices and increased unrealized losses on derivative instruments, offset by an increase in realized gains on derivatives. In 2009, prices on sales were 54.9% lower on average than in 2008, resulting in a \$107.7 million decrease in sales. In 2009, unrealized derivative gains on sales contracts decreased \$8.1 million from \$4.6 million in 2008 to a loss of \$3.5 million in 2009. These unrealized gains were partially offset by an increase in realized gains of \$7.6 million. Volumes sold decreased by 2% in 2009 compared to 2008, resulting in a \$3.7 million decrease in sales.

The decrease in costs of natural gas marketing in 2009 compared to 2008 is primarily due to a decrease in prices, increased unrealized gains, and a decrease in unrealized losses on derivative instruments. In 2009, prices on purchases were 52% lower on average than in 2008, resulting in a \$99.1 million decrease in costs. The unrealized gains on cost related contracts increased by \$9.7 million, and realized losses decreased by \$0.8 million. Volumes purchased for resale decreased by 2% in 2009 compared to 2008, resulting in a \$3.6 million decrease in costs.

The increase in sales from natural gas marketing in 2008 compared to 2007 is primarily due to an increase in prices and increased unrealized gains on derivative instruments. The increase in costs of natural gas marketing in 2008 compared to 2007 is primarily due to an increase in prices and increased unrealized losses on derivative

instruments. In 2008, prices on sales and purchases were 31.8% higher on average than in 2007, resulting in a \$27.8 million increase in sales and costs. The sales related unrealized gain on derivatives increased by \$6.4 million and the cost of sales related unrealized loss on derivatives increased by \$6.9 million. Volumes sold and purchased for resale decreased slightly by 2%.

Natural Gas Marketing Derivative Instruments. Our derivative instruments related to natural gas marketing include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. We do not take speculative positions on commodity prices.

Table of Contents

The following table presents our derivative positions related to our natural gas marketing in effect as of December 31, 2009.

Commodity/ Derivative Instrument	Quantity	Collars		Fixed-Price Swaps		NYMEX Basis Protection Swaps		Fair Value At December 31, 2009 (in thousands)
		Weighted Average Contract Price	Floors Ceilings (Gas-MMBtu)	Quantity	Weighted Average Contract Price	Quantity	Weighted Average Contract Price	
Natural Gas								
Physical Sales								
1Q 2010	-	\$-	\$-	206,368	\$5.85	131,411	\$0.37	\$ (2)
2Q 2010	-	-	-	38,154	6.76	8,948	0.96	35
3Q 2010	-	-	-	42,415	6.80	2,823	0.92	28
4Q 2010	-	-	-	29,573	6.77	17,506	0.78	13
2011	-	-	-	-	-	30,410	0.75	18
Financial Purchases								
1Q 2010	-	-	-	235,759	6.29	90,000	0.17	(152)
2Q 2010	-	-	-	37,659	5.44	-	-	4
3Q 2010	-	-	-	41,938	5.44	-	-	13
4Q 2010	-	-	-	29,374	5.41	-	-	22
Financial Sales								
1Q 2010	52,500	4.53	7.16	604,600	6.89	-	-	754
2Q 2010	52,500	4.53	7.16	603,600	6.71	-	-	694
3Q 2010	52,500	4.53	7.16	603,600	6.71	-	-	569
4Q 2010	52,500	4.53	7.16	517,600	6.81	-	-	300
2011	52,500	4.53	7.16	454,700	6.81	-	-	71
Physical Purchases								
1Q 2010	52,500	4.53	7.14	575,050	7.05	-	-	(621)
2Q 2010	52,500	4.53	7.14	604,050	6.66	-	-	(559)
3Q 2010	52,500	4.53	7.14	604,050	6.66	-	-	(436)
4Q 2010	52,500	4.53	7.14	517,750	6.78	-	-	(175)
2011	52,500	4.53	7.14	454,700	6.77	-	-	35
Total Natural Gas	525,000			6,200,940		281,098		\$ 611

Other Costs and Expenses

Exploration Expense and Impairment of Natural Gas and Oil Properties

The following table presents the major components of exploration expense and impairment of natural gas and oil properties.

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Impairment of proved natural gas and oil properties	\$926	\$12,825	\$-
Impairment/amortization of unproved properties	7,279	12,798	3,291
Exploratory dry holes	1,059	7,675	4,187
Geological and geophysical costs	1,788	2,121	6,299
Operating, personnel and other	11,835	9,686	9,774
Total exploration expense and impairment of natural gas and oil properties	\$22,887	\$45,105	\$23,551

Table of Contents

During 2009, we recognized, upon the termination of an exploration agreement, an impairment related to unproved properties in North Dakota of \$2.8 million and amortization of unproved properties of \$2.4 million in NECO and \$1.4 million in North Dakota. The majority of the geological and geophysical costs were related to seismic work in the Appalachian Basin related to our Marcellus development project. Included in operating, personnel and other is \$3.7 million for demobilization of our drilling operations in the Piceance Basin during 2009.

In 2008, we recognized impairment losses on proved natural gas and oil properties of \$12.8 million, consisting of \$7.5 million related to our properties in the Fort Worth Basin, \$3 million in our Bakken Field in North Dakota and \$2.3 million in our Nesson Field, also in North Dakota. We also recognized impairment losses on unproved properties of \$12.8 million, consisting primarily of \$7.3 million related to our unproved properties in the Fort Worth Basin and amortization of approximately \$5.5 million related to all of our other areas of operations. The \$7.7 million of exploratory dry holes relates primarily to two Michigan wells, one New York well and one Colorado well.

In 2007, exploration expense and impairment of natural gas and oil properties includes \$2.7 million of liquidated damages associated with the abandonment of an exploration agreement with an unaffiliated third party and \$1.1 million related to the write-off of the carrying value of the related acreage, \$6.3 million in geological and geophysical costs related to seismic evaluation of various exploratory prospects.

General and Administrative Expense

General and administrative expense increased from \$37.7 million in 2008 to \$54 million in 2009, an increase of \$16.3 million. The increase is primarily related to transaction costs associated with our joint venture of \$7.9 million, an increase in staffing and payroll benefits, including stock-based compensation of \$3.7 million, transaction costs of \$1.5 million related to an acquisition contemplated in the year prior to the adoption of new accounting rules and corporate headquarters relocation costs of \$1.3 million. See Note 2, Summary of Significant Accounting Policies – Recent Accounting Standards, to our consolidated financial statements included in this report.

The \$6.7 million increase in general and administrative expense in 2008 compared to 2007 was primarily due to increased payroll and payroll related expenses, which includes \$4.7 million related to agreements with two former executive officers: \$3.2 million related to a separation agreement with our former president and \$1.5 million related to an agreement for the retirement of our former chief executive officer. This increase was partially offset by a \$2 million decrease in audit fees and a decrease in various other general and administrative expenses.

Depreciation, Depletion and Amortization

Natural gas and oil properties. DD&A expense related to natural gas and oil properties is directly related to natural gas and oil reserves and production volumes. DD&A expense is primarily based upon year-end proved developed producing natural gas and oil reserves. For 2008 and 2007, these reserves were priced at the price of natural gas and oil as of December 31 for the respective year. New natural gas and reserve estimation and reporting requirements in 2009 changed the pricing measurement for reserve estimations from a December 31 single day pricing to a 12-month average of the first day of the month price for each month in the period. If prices increase, the estimated volumes of natural gas and oil reserves will increase, resulting in decreases in the rate of DD&A per unit of production. If prices decrease, as they did from December 31, 2008, to December 31, 2009, the estimated volumes of natural gas and oil reserves will decrease, resulting in increases in the rate of DD&A per unit of production. The weighted average DD&A rate for 2009 was \$2.83 per Mcfe compared to \$2.51 per Mcfe for 2008 and \$2.37 per Mcfe for 2007. Prior to 2009, the cost to acquire acreage, drill, complete and equip new wells had risen significantly over the past five years and is a major contributing factor to the increased DD&A rates in all areas.

Table of Contents

The following table presents our DD&A rate for natural gas and oil properties by area.

	Year Ended December 31,		
	2009	2008	2007
	(per Mcfe)		
Rocky Mountain Region:			
Wattenberg Field (1)	\$ 3.81	\$ 3.47	\$ 2.99
Grand Valley	2.35	2.04	2.27
NECO	1.85	1.45	1.45
Appalachian Basin	2.06	1.55	1.32
Weighted average	2.83	2.51	2.37

(1) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its oil production currently more than offsets this cost difference. The Wattenberg Field has produced volumes in excess of 89% of our total oil production in each of the years in the three-year period ended December 31, 2009.

Non natural gas and oil properties. Depreciation expense for non natural gas and oil properties was \$8.1 million for 2009 compared to \$7.6 million for 2008 and \$4.3 million for 2007.

Gain on Sale of Leaseholds

During 2007, we had two transactions involving leasehold sales. In May 2007, we entered into a letter agreement amending a 2006 purchase and sale agreement, relieving us of our obligation, in its entirety, to either drill 16 wells or pay liquidated damages of \$1.6 million per undrilled well. As a result, we recognized the remaining deferred gain of \$25.6 million in the second quarter of 2007. In December 2007, we sold to the same unaffiliated party a portion of our North Dakota properties for approximately \$34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and approximately 72,000 net undeveloped acres. We recorded a gain on sale of leaseholds of \$7.7 million in the fourth quarter of 2007.

Non-Operating Income/Expense

Interest Income. The decrease in our interest income for 2009 compared to 2008 and 2007 was the result of lower interest bearing cash balances and lower interest rates.

Interest Expense. The year-over-year increases in our interest expense were primarily due to significantly higher average outstanding balances of our credit facility offset in part by lower average interest rates in our bank credit facility. The average long-term debt in 2009 was \$392 million compared to \$275.9 million in 2008. Interest expense is net of capitalized interest. Interest costs capitalized in 2009, 2008 and 2007 were \$0.8 million, \$2.6 million and \$3 million, respectively. We have historically utilized our daily cash balances to reduce our line of credit borrowings,

thereby lowering our interest costs and, as discussed above, interest income.

Provision/Benefit for Income Taxes

The effective income tax rate for continuing operations ("rate") for 2009 was 36% (benefit on a loss) compared to 35.1% (provision on income) in 2008 and 38.8% (provision on income) in 2007. The 2009 rate was reduced by the tax effect of certain non-deductible expenditures and non-benefited losses associated with our new joint venture. The 2008 rate reflects a discrete tax benefit from state tax planning strategies implemented during 2008 for prior tax years. The 2007 rate approximates the combined statutory federal and state tax rates due to percentage depletion and domestic production deductions being offset by additional tax due to non-deductible penalties.

Our 2009 rate, excluding the effect of discrete items, was 36.2%. Our 2008 and 2007 rate, excluding the effect of discrete items, was 37.4% and 37%, respectively.

The federal examination of our 2005 and 2006 tax returns was completed in June 2009. Beginning with our 2010 tax year, we have been accepted into and have agreed to participate in the IRS Compliance Assurance Process Program. As part of our entrance into this program, we have agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination is scheduled to begin in April 2010.

Table of Contents

Discontinued Operations

Since 2007, we have not had significant revenue from our well drilling activities, and in January 2008, we announced that we had no plans to sponsor new drilling partnerships in 2008. We affirmed this position in 2009 to change our business model from a partnership sponsor to that of an independent exploration and production company. As of June 30, 2009, we had concluded all partnership drilling and completion activities. An unused advance of \$0.3 million was refunded to the partnerships in June 2009.

As we currently do not have any plans in the foreseeable future to sponsor a drilling partnership, we believe it was appropriate to treat our natural gas and oil well drilling activities as discontinued operations for all periods presented. Prior period financial statements have been restated to present the activities of our natural gas and oil well drilling operations as discontinued operations.

Net Income (Loss) Attributable to Shareholders/Adjusted Net Income (Loss) Attributable to Shareholders

Net loss attributable to shareholders for 2009 was \$79.3 million compared to a net gain of \$113.3 million for 2008 and \$33.2 million for 2007. Adjusted net loss attributable to shareholders, a non-GAAP financial measure for 2009 was \$2.9 million compared to an adjusted net income of \$39.7 million for 2008 and \$36 million for 2007. The year-over-year changes in net income (loss) attributable to shareholders are discussed above. These same reasons for change similarly impacted adjusted net income (loss) attributable to shareholders, with the exception of the unrealized derivative gains and losses on derivatives, adjusted for taxes. Adjusted net income (loss) attributable to shareholders excludes the impact of a tax adjusted unrealized derivative loss of \$74.6 million for 2009, a tax adjusted unrealized gain of \$76.2 million for 2008 and a tax adjusted unrealized loss of \$2.8 million for 2007. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of this non-GAAP financial measure.

Financial Condition

Capital Resources and Liquidity

Our primary sources of cash in 2009 were from funds generated from the sale of natural gas and oil production, the net realized gains from our derivative positions, the sale of common stock and the formation of the joint venture, which allowed us to monetize a portion of our Appalachian Basin assets. These sources of cash were primarily used to fund our operating costs, general and administrative activities and our capital expenditures, including both our developmental and exploratory activities. Additionally, we were able to improve our liquidity position during the uncertain economic time of 2009 by reducing our borrowings through payments on our credit facility. Our primary sources of cash from operations are sales of natural gas and oil. Fluctuations in our operating cash flow are substantially driven by commodity prices and change in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our derivative program. Therefore, the primary source of our cash flow from operations becomes the net activity between our natural gas and oil sales and realized derivative gains and losses. However, we do not hold economic hedges for more than 80% of our expected future production from producing wells and therefore may still have significant fluctuations in our cash flows from operations. Additionally, these fluctuations may result in an increase or decrease in our expected developmental and exploratory activities in the future. See Results of Operations for further discussion of the impact of prices and volumes on sales from operations and the impact of derivative activities on our revenues.

We entered 2010 with cash and cash equivalents of \$31.9 million and availability under our credit facility of \$206.3 million for a total liquidity position of \$238.2 million compared to \$231.5 million at the beginning of 2009. The increase in liquidity of \$6.7 million or 2.9% was achieved despite the \$70 million reduction in our total borrowing base, a new letter of credit on a pipeline commitment of \$18.7 million and the general downturn in the financial

markets and global economy. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. The primary factors affecting our working capital are our current unrealized derivative position, the timing of our payments to reduce our credit facility and the other variables discussed above. Our working capital surplus remained relatively unchanged from \$31.3 million at December 31, 2008, to \$32.9 million at December 31, 2009. The recent financial and credit crisis has reduced credit availability and liquidity for some companies; however, we believe we have adequate liquidity available to meet our working capital requirements. With our current liquidity position, including our working capital surplus and expected cash flow from operations, we believe that we have sufficient liquidity available to us for our planned uses of capital.

The key components impacting our cash flow from operations are commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. Cash provided by operating activities was \$143.9 million for 2009 compared to \$139.1 million for 2008. The \$4.8 million increase in 2009 was primarily due to the increase in realized gains from derivatives of \$106.2 million, decrease in natural gas and oil production and well operations costs of \$14.6 million offset by decrease in natural gas and oil sales of \$142.8 million and an increase in general and administrative costs from operating activities of \$16.3 million. The remaining change in our operating cash flow was primarily due to changes in our assets and liabilities related to the timing of cash payments and receipts. The key components for the changes in our cash flows from operations are described in more detail in our Results of Operations above.

Table of Contents

Adjusted cash flows from operations were \$170.2 million for 2009 compared to \$199.9 million for 2008. Adjusted EBITBA was \$159.7 million for 2009 compared to \$189.4 million for 2008. These decreases were primarily due to the same factors mentioned above for changes in cash provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of these non-GAAP financial measures.

Cash flows used in investing activities, primarily drilling capital expenditures, decreased \$180.7 million, or 55.9%, from \$323 million for 2008 to \$142.3 million for 2009. We reduced our planned 2009 capital expenditure program to preserve our liquidity position throughout 2009. We focused our drilling on our oil-rich section of our Wattenberg Field, where we drilled approximately 82% of our 2009 wells. Additionally, our other significant capital spend was drilling eight Marcellus wells in the Appalachian Basin. See Part I, Operations - Drilling Activities, for additional details on our 2009 drilling activity.

Cash flows provided from financing activities decreased \$170.7 million from a \$150.1 million source of cash for 2008 to a \$20.6 million use of cash for 2009. The decrease was due to the shift from net borrowings of \$159.6 million in 2008 to a net payment on borrowings of \$114.5 million in 2009. This \$274.1 million shift was offset by the proceeds from our equity offering of \$48.5 million and our joint venture investor partner's investment contribution of \$55 million, of which, at closing, we withdrew \$45 million as a return of capital and used the proceeds to reduce debt. See Note 8, Long-Term Debt, and Note 13, Noncontrolling Interest in Subsidiaries, to our consolidated financial statements included in this report for further discussion on our equity offering and joint venture.

Our primary use of funds is for capital expenditures. Our planned 2010 capital expenditures of \$149.9 million, for non joint venture related projects, represent an approximate 37% increase from our 2009 capital expenditures. We estimate our 2010 production to be 35.7 Bcfe, which includes our proportionate share of the joint venture, a decrease of approximately 17.6% over 2009 due to our reduced 2009 drilling program from that of 2008 and the contribution of a portion of our producing Appalachian properties to the joint venture. We believe, based on the current commodity price environment, our cash flows from operations will fund the majority of our 2010 capital spending program. In order to grow our production, unlike in 2009, we would need to commit greater amounts of capital in 2011 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our credit facility as the sources of funding for our capital expenditures. Because natural gas and oil produced from our existing properties declines rapidly in the first two years of production, we cannot maintain our current level of natural gas and oil production and cash flows from operations if capital markets and commodity prices remain in their current depressed state for a prolonged period beyond 2009, which could have a material negative impact on our operations in 2010 and beyond.

We considered the possibility of reduced available liquidity in planning our 2010 drilling program and believe we will have adequate cash flows from operations during the year to execute our planned capital expenditures. Currently, we operate approximately 92.7% of our properties, allowing us to direct the pace of substantially all of our planned capital expenditures. Consequently, we may elect to defer a substantial portion of our planned capital expenditures for 2010 and beyond if market conditions worsen.

We have experienced no impediments in our ability to access borrowings under our current bank credit facility or the capital markets, as demonstrated by our August 2009 sale of equity. We continue to monitor market events and circumstances and their potential impacts on each of the 13 lenders that comprise our bank credit facility. Our \$305 million bank credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base.

While we have continued to add producing reserves through our drilling operations since our last redetermination, we believe a significant decrease in commodity prices and turmoil in the credit markets could have a negative impact on our May 2010 borrowing base redetermination.

In August 2009, we issued a \$18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider to secure the construction of certain additions and/or replacements to its facilities to provide firm transportation of the natural gas produced by us and others for whom we market their production in the West Virginia and Southwestern Pennsylvania area. The letter of credit, even if undrawn, reduces the amount of available funds under our credit facility by an equal amount. We pay a fronting fee of 0.25% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.5% as of December 31, 2009) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

Table of Contents

We are subject to quarterly financial debt covenants on our bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.25 times earnings before interest, taxes, DD&A expense and capital expenditures ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our natural gas and oil derivative instruments and adding our available borrowings on our bank credit facility to our current assets. In addition, the impact of any current portion of our debt is eliminated from the current liabilities. Therefore, any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at December 31, 2009.

The indenture governing our senior notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. Additionally, we are subject to two incurrence covenants: 1) EBITDAX of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants as of December 31, 2009.

We believe we have sufficient liquidity and capital resources to conduct our business and remain compliant with our debt covenants throughout the next year based upon our 2010 cash flow projections, anticipated capital requirements, the discretionary nature of our capital expenditures and available capacity under our bank credit facility. However, we cannot predict with any certainty the impact to our future business of any continued uncertainty or further deterioration in the financial or commodity markets. We will continue to closely monitor our liquidity and the credit markets and may choose to access them opportunistically should conditions and capital market liquidity improve.

We filed a shelf registration statement on Form S-3 with the SEC on November 26, 2008. The shelf provides for an aggregate of \$500 million, through the potential sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow us to be proactive in our ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. This shelf registration statement was declared effective by the SEC on January 30, 2009. Following our equity offering in August 2009, we now have available \$448.2 million of our shelf from which we may utilize to raise capital.

See Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for our discussion of credit risk.

Contractual Obligations and Contingent Commitments

The table below presents our contractual obligations and contingent commitments as of December 31, 2009.

Contractual Obligations and Contingent Commitments	Total	Payments due by period			
		Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-term liabilities reflected on the consolidated balance sheets (1)					
Long-term debt	\$280,657	\$-	\$80,000	\$-	\$200,657
Asset retirement obligations	29,564	250	500	1,000	27,814
Derivative contracts (2)	65,844	17,065	36,179	12,600	-

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Derivative contracts - partnerships (3)	6,660	665	4,355	1,640	-
Production tax liability	36,100	21,542	14,558	-	-
Other liabilities (4)	10,336	352	3,515	770	5,699
	429,161	39,874	139,107	16,010	234,170
Commitments, contingencies and other arrangements (5)					
Interest on long-term debt (6)	206,892	28,105	53,942	48,720	76,125
Operating leases	6,817	2,001	2,422	1,749	645
Drilling commitment (7)	1,800	-	-	-	1,800
Firm transportation and processing agreements (8)	179,884	18,483	38,025	41,989	81,387
Other	750	125	250	250	125
	396,143	48,714	94,639	92,708	160,082
Total	\$825,304	\$88,588	\$233,746	\$108,718	\$394,252

Table of Contents

- (1) Table does not include deferred income tax liability to taxing authorities of \$178 million as of December 31, 2009, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.
- (2) Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of \$21 million as of December 31, 2009.
- (3) Represents our affiliated partnerships' designated portion of the fair value of our gross derivative assets as of December 31, 2009.
- (4) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.
- (5) Table does not include maximum annual repurchase obligations to investing partners of \$9.4 million as of December 31, 2009, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.
- (6) Amounts presented for long term debt consist of amounts related to our 12% senior notes and our outstanding credit facility. The interest on long-term debt includes \$197.9 million payable to the holders of our 12% senior notes and \$8.5 million related to our outstanding balance of \$80 million on our credit facility as of December 31, 2009, including interest of \$0.5 million related to our letter of credit, based on an imputed interest rate of 4.7%.
- (7) See Note 11, Commitments and Contingencies – Drilling and Development Agreements, to our consolidated financial statements included in this report.
- (8) Represents our gross commitment, including amounts for volumes transported or sold on behalf of our affiliated partnerships and other working interest owners. We will recognize in our financial statements our proportionate share based on our working interest. See Note 11, Commitments and Contingencies – Firm Transportation Agreements, to our consolidated financial statements included in this report.

As managing general partner of 33 partnerships (see Item 1. Business – Drilling and Development Conducted for Company Sponsored Partnerships), we have liability for potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings, see Note 11, Commitments and Contingencies – Litigation, to our consolidated financial statements included in this report. From time to time we are a party to various other legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse affect on our business, financial condition, results of operations, or liquidity.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to business operations and the understanding of our results of operations. This is not a comprehensive list of all of the accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by accounting principles generally accepted in the U.S., with no need for our judgment in the application. There are also areas in which our judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and we may use significant judgment in the application; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, we use our judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see Note 2, Summary of Significant Accounting Policies, to our consolidated financial statements included in this report. Our critical accounting policies and estimates are as follows:

Revenue Recognition

Natural gas and oil sales. Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered to a purchaser, collection of revenue from the sale is reasonably assured and the sales price is determinable. We are currently able to sell all the oil that we can produce under existing sales contracts with petroleum refiners and marketers. We do not refine any of our oil production. Our crude oil production is sold to purchasers at or near our wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the industry.

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold by us under contracts with terms ranging from one month to three years. Virtually all of our contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, our revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry.

Table of Contents

We currently use the "net-back" method of accounting for transportation arrangements of natural gas sales. We sell gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by our customers and reflected in the wellhead price.

Natural gas marketing. Natural gas marketing is reported on the gross accounting method, based on the nature of the agreements between RNG, our suppliers and our customers. RNG, our marketing subsidiary, purchases gas from PDC and other small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. RNG has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the realized and unrealized gains and losses of the RNG commodity-based derivative transactions for natural gas marketing are included in sales from natural gas marketing or cost of natural gas marketing, as applicable.

Well operations and pipeline income. Well operations and pipeline income are recognized when persuasive evidence of an arrangement exists, services have been rendered, collection of revenues is reasonably assured and the sales price is fixed or determinable. We are paid a monthly operating fee for each well we operate for outside owners including the limited partnerships we sponsor. The fee covers monthly operating and accounting costs, insurance and other recurring costs. We may also receive additional compensation for special non-recurring activities, such as workovers and recompletions.

Fair Value of Financial Instruments

Determination of Fair Value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Included in Level 1 are our commodity derivative instruments for NYMEX-based natural gas swaps.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Included in Level 3 are our commodity derivative instruments for CIG and PEPL-based natural gas swaps, oil swaps, natural gas and oil collars, and physical sales and purchases and our natural gas basis protection derivative instruments.

Derivative Financial Instruments. We measure fair value of our derivatives based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the

source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to our nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use two investment grade financial institutions as our counterparties to our derivative contracts. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2009, no valuation allowance was recorded. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

Table of Contents

Non-Derivative Financial Assets and Liabilities. The carrying values of the financial instruments comprising cash and cash equivalents and restricted cash approximate fair value due to the short-term maturities of these instruments.

The portion of our long-term debt related to our credit facility, approximates fair value due to the variable nature of its related interest rate. We estimate the fair value of the portion of our long-term debt related to our senior notes to be approximately \$210.1 million or approximately 103.5% of par value as of December 31, 2009. We determined this valuation based upon measurements of trading activity.

Natural Gas and Oil Properties

We account for our natural gas and oil properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and development dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing natural gas and oil reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved natural gas and oil reserves.

Annually, we engage independent petroleum engineers to prepare reserve and economic evaluations of all our properties on a well-by-well basis as of December 31. Additionally, we adjust our natural gas and oil reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating natural gas and oil reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates over time. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have an effect on our net income.

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify our completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful prior to the issuance of the financial statements, the costs incurred, including costs for plugging, prior to the end of the reporting period are expensed to exploration expense and impairment of natural gas and oil properties. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the well is classified as "suspended well costs" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well's productive status, the well is removed from the suspended well status and the proper accounting treatment is applied.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved natural gas and oil properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to exploration expense and impairment of natural gas and oil properties. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of

such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms. The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

We assess our natural gas and oil properties for possible impairment by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of natural gas and oil. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future net cash flows and an impairment of our natural gas and oil properties. Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results.

Table of Contents

Deferred Income Tax Asset Valuation Allowance

Deferred income tax assets are recognized for deductible temporary differences, net operating loss carry-forwards and credit carry-forwards if it is more likely than not that the tax benefits will be realized. To the extent a deferred tax asset is not expected to be realized under the preceding criteria, a valuation allowance is established. The factors which we consider in assessing whether we will realize the value of deferred income tax assets involve judgments and estimates of both amount and timing, which could differ from actual results, achieved in future periods.

The judgments used in applying the above policies are based on our evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results may differ from those estimates.

Accounting for Acquisitions Using Purchase Accounting

We utilize the purchase method to account for acquisitions. Pursuant to purchase method accounting, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on appraisals, discounted cash flows, quoted market prices and estimates by management. In addition, when appropriate, we review comparable purchases and sales of natural gas and oil properties within the same regions, and use that data as a basis for fair market value; for example, the amount a willing buyer and seller would enter into an exchange for such properties.

In estimating the fair values of assets acquired and liabilities assumed we made various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped, unproved natural gas and oil properties and other non natural gas and oil properties. To estimate the fair values of these properties, we prepared estimates of natural gas and oil reserves. We estimated future prices to apply to the estimated reserve quantities acquired, and estimated future operating and development costs, to arrive at estimates of future net revenues. For estimated proved reserves, the future net revenues were discounted using a market-based weighted average cost of capital rate determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rate was subjected to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable and possible reserves were reduced by additional risk-weighting factors.

Deferred taxes must be recorded for any differences between the assigned values and tax basis of assets and liabilities. Estimated deferred taxes are based on available information concerning the tax basis of assets acquired and liabilities assumed and loss carryforwards at the acquisition date, although such estimates may change in the future as additional information becomes known.

Recent Accounting Standards

See Note 2, Summary of Significant Accounting Policies - Recent Accounting Standards, to our consolidated financial statements included in this report.

Reconciliation of Non-GAAP Financial Measures

Adjusted cash flow from operations. We define adjusted cash flow from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flow from operations as well as cash flow from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the earned or

incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices. See the Consolidated Statements of Cash Flows in this report.

Adjusted net income (loss) attributable to shareholders. We define adjusted net income (loss) attributable to shareholders as net income (loss) attributable to shareholders plus unrealized derivative losses, provisions for underpayment of gas sales, minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss) attributable to shareholders as well as net income (loss) attributable to shareholders. We believe it often provides more transparency into our operating trends, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) attributable to shareholders from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives. Additionally, other items, such as the provision for underpayment of gas sales, which are not indicative of future results, may be excluded to clearly identify operational trends.

Table of Contents

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus unrealized derivative loss, interest expense, net of interest income, income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gain. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a widely used industry metric which allows comparability of our results with our peers.

The following table presents a reconciliation of each of our non-GAAP financial measures to its nearest GAAP measure.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands, except share and per share data)		
Adjusted cash flow from operations:			
Net cash provided by operating activities	\$ 143,895	\$ 139,101	\$ 60,304
Total changes in current assets and liabilities	26,319	60,818	35,322
Adjusted cash flow from operations	\$ 170,214	\$ 199,919	\$ 95,626
Adjusted net income (loss) attributable to shareholders:			
Net income (loss) attributable to shareholders	\$(79,277)	\$ 113,309	\$ 33,209
Unrealized loss (gain) on derivatives, net	116,623	(117,536)	4,642
Provision for underpayment of gas sales	2,706	4,025	-
Tax effect of above adjustments	(42,981)	39,887	(1,801)
Adjusted net income (loss) attributable to shareholders	\$(2,929)	\$ 39,685	\$ 36,050
Adjusted EBITDA:			
Net income (loss) attributable to shareholders	\$(79,277)	\$ 113,309	\$ 33,209
Unrealized loss (gain) on derivatives, net	116,623	(117,536)	4,642
Interest expense, net	36,954	27,541	6,617
Income tax expense (benefit)	(45,636)	61,459	20,981
Depreciation, depletion and amortization	131,004	104,640	70,885
Adjusted EBITDA	\$ 159,668	\$ 189,413	\$ 136,334

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

We are exposed to market risks associated with interest rates, commodity prices and credit exposure. Management has established risk management processes to monitor and manage these market risks.

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and restricted cash and the interest we pay on borrowings under our bank credit facility. Our 12% senior notes are fixed rate and, therefore, do not expose us to the cash flow loss due to changes in market interest rate. However, changes in interest rates do affect the fair value of our senior notes.

We are exposed to risk resulting from changes in interest rates primarily as it relates to interest we earn on our deposit accounts, including cash, cash equivalents and designated cash, current and noncurrent, and interest we pay on

borrowings under our revolving credit facility. Our interest-bearing deposit accounts include money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of December 31, 2009, is \$31.8 million with an average interest rate of 0.9%.

Based on a sensitivity analysis of the credit facility borrowings as of December 31, 2009, it was estimated that if market interest rates were to average 1% higher (lower) in 2010 than in 2009, our interest expense, net of tax, would increase (decrease) by approximately \$2.8 million.

Table of Contents

Commodity Price Risk

We are exposed to the effect of market fluctuations in the prices of natural gas and oil. Price risk represents the potential risk of loss from adverse changes in the market price of natural gas and oil commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using derivative instruments. Our policy prohibits the use of natural gas and oil derivative instruments for speculative purposes.

See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report for a discussion of how we determine and account for our derivative contracts at fair value.

The following table presents monthly average NYMEX and CIG closing prices for natural gas and oil for the years ended December 31, 2009, and 2008, as well as average sales prices we realized for the respective commodities.

	Year Ended December 31,	
	2009	2008
Average Index Closing Price Natural Gas (per MMBtu)		
CIG	\$ 3.07	\$ 6.22
NYMEX	3.99	9.04
Oil (per Barrel)		
NYMEX	58.36	104.42
Average Sales Price		
Natural Gas	3.12	6.98
Oil	55.03	89.77

Based on a sensitivity analysis as of December 31, 2009, it was estimated that a 10% increase or decrease in natural gas and oil prices, inclusive of basis, over the entire period for which we have derivatives then in place would result in a decrease or increase, respectively, in fair value of \$55.5 million.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Results of Operations, Commodity Price Risk Management, Net and Natural Gas Marketing, for a detailed discussion of open derivative positions related to our natural gas and oil sales activities and our natural gas marketing. See Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report for a summary of our open derivative positions as of December 31, 2009.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When exposed to credit risk, we analyze the counterparties' financial condition prior

to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

With regard to our natural gas and oil sales segment, inherent to our industry is the concentration of natural gas and oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. As for our natural gas marketing segment, our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries. We monitor their creditworthiness through credit reports and rating agency reports. To date, we have had no counterparty default losses in either of our natural gas and oil sales segment or natural gas marketing segment. See Note 5, Concentration of Risk, to our consolidated financial statements included in this report.

Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. We primarily use financial institutions, which are also major lenders in our credit facility, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2009, no adjustment for credit risk was recorded.

Table of Contents

The recent disruption in the credit market has had a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance in these uncertain times.

Disclosure of Limitations

Because the information above included only those exposures that exist at December 31, 2009, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our hedging strategies at the time, and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The response to this Item is set forth herein in a separate section of this report, beginning on Page F-1.

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2009, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e), and based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2009.

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2009, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information called for by this Item is incorporated by reference from information under the captions entitled Corporate Governance, Section 16(a) Beneficial Ownership Reporting Compliance, Election of Directors and Executive Compensation and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by this Item is incorporated by reference from information under the caption entitled Executive Compensation and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

49

Table of Contents

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

The information called for by this Item is incorporated by reference from information under the caption entitled Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information called for by this Item is incorporated by reference from information under the captions entitled Certain Relationships and Related Transactions and Director Independence in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information called for by this Item is incorporated by reference from information under the caption entitled Principal Accountant Fees and Services and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

- (a) (1) Financial Statements:
See Index to Financial Statements and Schedules on page F-1.
- (2) Financial Statement Schedules:
See Index to Financial Statements and Schedules on page F-1.
Schedules and Financial Statements Omitted
All other financial statement schedules are omitted because they are not required, inapplicable, or the information is included in the Financial Statements or Notes thereto.
- (3) Exhibits:
See Exhibits Index on page 54.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PETROLEUM DEVELOPMENT
CORPORATION

By /s/ Richard W. McCullough
Richard W. McCullough,
Chairman, Chief Executive Officer, and
President

March 4, 2010

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

Signature	Title	Date
/s/ Richard W. McCullough Richard W. McCullough	Chairman, Chief Executive Officer, and President (principal executive officer)	March 4, 2010
/s/ Gysle R. Shellum Gysle R. Shellum	Chief Financial Officer (principal financial officer)	March 4, 2010
/s/ R. Scott Meyers R. Scott Meyers	Chief Accounting Officer (principal accounting officer)	March 4, 2010
/s/ Daniel W. Amidon Daniel W. Amidon	General Counsel, Corporate Secretary	March 4, 2010
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	March 4, 2010
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	March 4, 2010
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	March 4, 2010
/s/ David C. Parke David C. Parke	Director	March 4, 2010
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	March 4, 2010
/s/ Joseph E. Casabona	Director	March 4, 2010

Joseph E. Casabona

/s/ Larry F. Mazza
Larry F. Mazza

Director

March 4, 2010

/s/ James M. Trimble
James M. Trimble

Director

March 4, 2010

Table of Contents

GLOSSARY OF NATURAL GAS AND OIL TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report.

CIG - Colorado Interstate Gas.

Completion - The installation of permanent equipment for the production of oil or gas.

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

Dry hole - A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion as an oil or gas well.

Exit rate - Natural gas equivalent produced as of the date specified.

Exploratory well - A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

Extensions and discoveries - As to any period, the increases to proved reserves from all sources other than the acquisition of proved properties or revisions of previous estimates.

Farm-out - Transfer of all or part of the operating rights from a working interest owner to an assignee, who assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty but may retain any type of interest.

Gross acres or wells - Refers to the total acres or wells in which we have a working interest.

Horizontal drilling - A drilling technique that permits the operator to contact and intersect a larger portion of the producing horizon than conventional vertical drilling techniques and may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

Joint Interest Billing or JIB - Process of distributing the costs related to well completions and operations among working interest partners.

Natural Gas Liquids or NGLs - Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane, and natural gasolines.

Net acres or wells - Refers to gross acres or wells multiplied, in each case, by the percentage working interest we own.

Net production - Natural gas and oil production that we own, less royalties and production due others.

NYMEX - New York Mercantile Exchange.

Operator - The individual or company responsible for the exploration, development and/or production of an oil or gas well or lease.

PEPL - Panhandle Eastern Pipeline.

Present value of proved reserves - The present value of estimated future revenues, discounted at 10% annually, to be generated from the production of proved reserves determined in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, without giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, (ii) non-property related expenses such as general and administrative expenses, debt service and future income tax expense, or (iii) DD&A expense.

Proved developed non-producing reserves - Reserves that consist of (i) proved reserves from wells which have been completed and tested but are not producing due to lack of market or minor completion problems which are expected to be corrected and (ii) proved reserves currently behind the pipe in existing wells and which are expected to be productive due to both the well log characteristics and analogous production in the immediate vicinity of the wells.

Proved developed producing reserves - Proved reserves that can be expected to be recovered from currently producing zones under the continuation of present operating methods.

Table of Contents

Proved developed reserves - The combination of proved developed producing and proved developed non-producing reserves.

Proved reserves - Those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing conditions, operating methods, and government regulations - prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonable certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

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

Recompletion - A recompletion occurs when we reenter a well to complete (i.e., perforate) a new formation different from that in which a well has previously been completed.

Refrac or refracture - A refrac is when we stimulate the present producing zone of a well to increase production, using hydraulic, acid, gravel, etc. fracture techniques.

Reserve replacement - Calculated by dividing the sum of reserve additions from all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values used for reserve additions are derived directly from the proved reserves table located in Supplemental Information - Natural Gas and Oil Operations to our consolidated financial statements included in this report. We use the reserve replacement ratio as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio is limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

Reserves - Estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and gas or related substance to market, and all permits and financing required to implement the project.

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

Standardized measure of discounted future net cash flows - Present value of proved reserves, as adjusted to give effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment, and (ii) estimated future income taxes.

Trunk Line - A pipeline for the transportation of oil or natural gas from producing areas to refineries or terminals.

Undeveloped acreage - Leased acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas and oil, regardless of whether such acreage contains proved reserves.

Wellbore - A physical hole that makes up the well, and can be cased, open or a combination of both.

Working interest - An interest in an natural gas and oil lease that gives the owner of the interest the right to drill for and produce natural gas and oil on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest is entitled will be smaller than the share of costs that the working interest owner is required to bear to the extent of any royalty burden.

Workover - Operations on a producing well to restore or increase production.

Table of Contents

Exhibits Index

Exhibit Number	Exhibit Description	Form	Incorporated by Reference		Filing Date	Filed Herewith
			SEC File Number	Exhibit		
3.1	Second Amended and Restated Certificate of Incorporation of Petroleum Development Corporation.	8-K	000-07246	3.1	7/23/2008	
3.2	Bylaws of Petroleum Development Corporation, amended and restated, effective October 11, 2007.	8-K	000-07246	3.2	10/17/2007	
4.1	Rights Agreement by and between Petroleum Development Corporation and Transfer Online, Inc., as Rights Agent, dated as of September 11, 2007, including the forms of Rights Certificates and Summary of Stockholder Rights Plan attached thereto as Exhibits A and B.	8-K	000-07246	4.1	9/14/2007	
4.2	Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and The Bank of New York.	8-K	000-07246	4.1	2/12/2008	
4.3	First Supplemental Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and the Bank of New York.	8-K	000-07246	4.2	2/12/2008	
4.4	Form of 12% Senior Note due 2018.	8-K	000-07246	4.3	2/12/2008	
10.1	Purchase Agreement dated as of February 1, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	2/7/2008	
10.2	Registration Rights Agreement dated as of February 8, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	2/12/2008	
10.3	Amended and Restated Credit Agreement dated as of November 4,	8-K	000-07246	10.1	11/4/2005	

2005, Petroleum Development Corporation, as borrower and JPMorgan Chase Bank, N.A and BNP Paribas, as lenders.

10.4	First Amendment to Amended and Restated Credit Agreement, dated as of August 9, 2007, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., BNP Paribas and Wachovia Bank, N.A.	8-K	000-07246	10.1	8/15/2007
10.5	Second Amendment to Amended and Restated Credit Agreement, dated as of October 16, 2007, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., and various other banks.	8-K	000-07246	10.1	10/22/2007

Table of Contents

Exhibit Number	Exhibit Description	Form	Incorporated by Reference		Filing Date	Filed Herewith
			SEC File Number	Exhibit		
10.6	Third Amendment to Amended and Restated Credit Agreement dated as of July 15, 2008, by and among Petroleum Development Corporation, certain of its subsidiaries, JP Morgan Chase Bank, N.A., and various other banks.	8-K	000-07246	10.1	7/21/2008	
10.7	Fourth Amendment to Amended and Restated Credit Agreement dated as of July 18, 2008, by and among the Company, certain of its subsidiaries, JP Morgan Chase Bank, N.A., and various other banks.	8-K	000-07246	10.2	7/21/2008	
10.8	Fifth Amendment to Amended and Restated Credit Agreement dated as of November 12, 2008, by and among the Company, certain of its subsidiaries, JP Morgan Chase Bank, N.A., and various other banks.	8-K	000-07246	10.1	11/19/2008	
10.9	Sixth Amendment to Amended and Restated Credit Agreement dated as of May 22, 2009, by and among the Company, certain of its subsidiaries, JPMorgan Chase Bank, N.A., and various other banks.	8-K	000-07246	10.1	5/29/2009	
10.10	Seventh Amendment to Amended and Restated Credit Agreement entered into as of October 29, 2009, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A. and various other banks.	8-K	000-07246	10.2	11/4/2009	
<u>10.11</u>	Eighth Amendment to Amended and Restated Credit Agreement entered into as of December 18, 2009, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A. and various other banks.					X
10.12		8-K	000-07246	1.1	8/11/2009	

	Underwriting Agreement dated August 11, 2009 among the Company and J.P. Morgan Securities Inc., as representative of the several Underwriters named therein.				
10.13*	2009 Short-Term Incentive Compensation Terms for Executive Officers.	8-K	000-07246		4/6/2009
10.14*	2009 Long-Term Incentive Program (as amended for 2009) for Executive Officers.	8-K	000-07246	10.1	3/5/2009
10.15*	Non-Employee Director Compensation for the 2009-2010 Term.	8-K	000-07246		3/5/2009
10.16*	2009 Base Salary Program for Executive Officers.	8-K	000-07246		1/7/2009
10.17*	2006 Long-Term Equity Compensation Grants to Executive Officers.	8-K	000-07246	10.20	4/10/2007
10.18*	Employment agreement with R. Scott Meyers, Chief Accounting Officer.	8-K	000-07246		4/8/2009
10.19*	Indemnification Agreement with Directors.	10-Q	000-07246	10.1	8/9/2007

Table of Contents

Exhibit Number	Exhibit Description	Form	Incorporated by Reference SEC File Number	Exhibit	Filing Date	Filed Herewith
10.20*	The Petroleum Development Corporation 401(k) & Profit Sharing Plan.	S-8	333-137836	4.1	10/5/2006	
10.21*	2005 Non-Employee Director Restricted Stock Plan, amended and restated as of March 8, 2008.	S-8	000-07246	10.1	2/26/2009	
10.22*	Separation Agreement of Steven R. Williams, former Director.	8-K	000-07246		4/29/2009	
10.23*	Resignation of Eric R. Stearns, Executive Vice President.	8-K	000-07246		5/22/2009	
10.24	Contribution Agreement by and among PDC Mountaineer, LLC, as the Company, Petroleum Development Corporation, as the Contributor, and LR-Mountaineer Holdings, L.P., as the Investor, dated October 29, 2009.	8-K	000-07246	2.1	11/4/2009	
10.25	Limited Liability Company Agreement of PDC Mountaineer, LLC, dated October 29, 2009.	8-K	000-07246	10.1	11/4/2009	
<u>12.1</u>	Computation of Ratio of Earnings to Fixed Charges.					X
14.1	Code of Business Conduct and Ethics.	10-Q	000-07246	14.1	8/10/2009	
<u>21.1</u>	Subsidiaries.					X
<u>23.1</u>	Consent of PricewaterhouseCoopers LLP.					X
<u>23.2</u>	Consent of Wright & Company, Inc., Petroleum Consultants.					X
<u>23.3</u>	Consent of Ryder Scott Company, L.P., Petroleum Consultants.					X
<u>31.1</u>	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X

<u>31.2</u>	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	X
<u>32.1</u>	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.	X
<u>99.1</u>	Report of Independent Petroleum Consultants - Wright & Company, Inc.	X
<u>99.2</u>	Report of Independent Petroleum Consultants - Ryder Scott Company, L.P.	X

*Management contract or compensatory plan or arrangement.

Table of Contents

Index to Consolidated Financial Statements and Financial Statement Schedule

<u>Management's Report on Internal Control Over Financial Reporting</u>	F-2
Financial Statements:	
<u>Report of Independent Registered Public Accounting Firm</u>	F-3
<u>Consolidated Balance Sheets - December 31, 2009 and 2008</u>	F-4
<u>Consolidated Statements of Operations - Years Ended December 31, 2009, 2008 and 2007</u>	F-5
<u>Consolidated Statements of Cash Flows - Years Ended December 31, 2009, 2008 and 2007</u>	F-6
<u>Consolidated Statements of Equity - Years Ended December 31, 2009, 2008 and 2007</u>	F-7
Notes to Consolidated Financial Statements	
<u>Note 1 – Nature of Operations and Basis of Presentation</u>	F-8
<u>Note 2 – Summary of Significant Accounting Policies</u>	F-8
<u>Note 3 – Fair Value of Financial Instruments</u>	F-17
<u>Note 4 – Derivative Financial Instruments</u>	F-19
<u>Note 5 – Concentration of Credit Risk</u>	F-21
<u>Note 6 – Properties and Equipment</u>	F-23
<u>Note 7 – Income Taxes</u>	F-24
<u>Note 8 – Long-Term Debt</u>	F-26
<u>Note 9 – Asset Retirement Obligations</u>	F-29
<u>Note 10 – Employee Benefit Plans</u>	F-29
<u>Note 11 – Commitments and Contingencies</u>	F-29
<u>Note 12 – Common Stock</u>	F-33
<u>Note 13 – Noncontrolling Interest in Subsidiaries</u>	F-37
<u>Note 14 – Business Segments</u>	F-38
<u>Note 15 – Transactions with Affiliates</u>	F-39
<u>Note 16 – Discontinued Operations</u>	F-40
<u>Note 17 – Sale of Natural Gas and Oil Properties</u>	F-41
<u>Note 18 – Acquisitions</u>	F-41
Supplemental Information – Unaudited	
<u>Natural Gas and Oil Operations</u>	F-43
<u>Quarterly Financial Data</u>	F-48
Financial Statement Schedule:	
<u>Schedule II – Valuation and Qualifying Accounts and Reserves</u>	F-50

Table of Contents

Management's Report on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act. Internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies or procedures may deteriorate.

Management has assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2009, based upon the criteria established in "Internal Control – Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on this evaluation, management concluded that the Company maintained effective internal control over financial reporting as of December 31, 2009.

The effectiveness of Petroleum Development Corporation's internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

PETROLEUM DEVELOPMENT CORPORATION

/s/ Richard W. McCullough
Richard W. McCullough
Chairman and Chief Executive Officer

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Petroleum Development Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, equity, and cash flows present fairly, in all material respects, the financial position of Petroleum Development Corporation and its subsidiaries at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 7 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions in 2007.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies

or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP
Pittsburgh, Pennsylvania

March 4, 2010

F-3

Table of Contents

Petroleum Development Corporation
Consolidated Balance Sheets
(in thousands, except share and per share data)

December 31,	2009	2008
Assets		
Current assets:		
Cash and cash equivalents	\$31,944	\$50,950
Restricted cash	2,490	19,030
Accounts receivable, net	56,491	69,688
Accounts receivable affiliates	7,956	16,742
Fair value of derivatives	42,223	116,881
Income tax receivable	27,728	-
Prepaid expenses and other current assets	8,538	19,146
Total current assets	177,370	292,437
Properties and equipment, net	1,008,193	1,033,078
Fair value of derivatives	20,228	47,155
Accounts receivable affiliates	15,473	1,605
Other assets	29,063	28,429
Total Assets	\$1,250,327	\$1,402,704
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	\$36,845	\$90,532
Accounts payable affiliates	13,015	40,540
Production tax liability	24,849	18,226
Fair value of derivatives	20,208	4,766
Funds held for distribution	28,256	50,361
Deferred income taxes	-	28,355
Other accrued expenses	21,261	28,391
Total current liabilities	144,434	261,171
Long-term debt	280,657	394,867
Deferred income taxes	178,012	162,593
Asset retirement obligation	29,314	23,036
Fair value of derivatives	48,779	5,720
Accounts payable affiliates	5,996	10,136
Other liabilities	24,542	32,906
Total liabilities	711,734	890,429
COMMITMENTS AND CONTINGENT LIABILITIES		
Equity		
Shareholders' equity:		
Preferred shares, par value \$.01 per share; authorized 50,000,000 shares; issued: none	-	-
Common shares, par value \$.01 per share; authorized 100,000,000 shares; issued: 19,242,219 in 2009 and 14,871,870 in 2008	192	149
Additional paid-in capital	64,406	5,818
Retained earnings	426,629	505,906

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Treasury shares, at cost: 8,273 shares in 2009 and 7,066 in 2008	(312)	(292)
Total shareholders' equity	490,915	511,581
Noncontrolling interest in subsidiaries	47,678	694
Total equity	538,593	512,275
Total Liabilities and Equity	\$1,250,327	\$1,402,704

See accompanying Notes to Consolidated Financial Statements.

F-4

Table of Contents

Petroleum Development Corporation
Consolidated Statements of Operations
(in thousands, except per share data)

Year Ended December 31,	2009	2008	2007
Revenues:			
Natural gas and oil sales	\$ 179,093	\$ 321,877	\$ 175,187
Sales from natural gas marketing	64,635	140,263	103,624
Commodity price risk management gain (loss), net	(10,053)	127,838	2,756
Well operations, pipeline income and other	11,043	11,767	10,170
Total revenues	244,718	601,745	291,737
Costs and expenses:			
Natural gas and oil production and well operations costs	64,746	79,354	49,833
Cost of natural gas marketing	62,534	139,234	100,584
Exploration expense and impairment of natural gas and oil properties	22,887	45,105	23,551
General and administrative expense	53,985	37,715	30,968
Depreciation, depletion, and amortization	131,004	104,640	70,885
Total costs and expenses	335,156	406,048	275,821
Gain on sale of leaseholds	470	-	33,291
Income (loss) from operations	(89,968)	195,697	49,207
Interest income	254	591	2,662
Interest expense	(37,208)	(28,132)	(9,279)
Income (loss) from continuing operations before income taxes	(126,922)	168,156	42,590
Provision (benefit) for income taxes	(45,716)	59,089	16,505
Income (loss) from continuing operations	(81,206)	109,067	26,085
Income from discontinued operations, net of tax	113	4,177	7,083
Net income (loss)	(81,093)	113,244	33,168
Less: net loss attributable to noncontrolling interests	(1,816)	(65)	(41)
Net income (loss) attributable to shareholders	\$(79,277)	\$ 113,309	\$ 33,209
Amounts attributable to Petroleum Development Corporation shareholders:			
Income (loss) from continuing operations	\$(79,390)	\$ 109,132	\$ 26,126
Income from discontinued operations, net of tax	113	4,177	7,083
Net income (loss) attributable to shareholders	\$(79,277)	\$ 113,309	\$ 33,209
Earnings (loss) per share attributable to shareholders:			
Basic			
Income (loss) from continuing operations	\$(4.83)	\$ 7.41	\$ 1.77
Income from discontinued operations	0.01	0.28	0.48
Net income (loss) attributable to shareholders	\$(4.82)	\$ 7.69	\$ 2.25
Diluted			
Income (loss) from continuing operations	\$(4.83)	\$ 7.35	\$ 1.76
Income from discontinued operations	0.01	0.28	0.48

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Net income (loss) attributable to shareholders	\$ (4.82) \$ 7.63	\$ 2.24
Weighted average common shares outstanding			
Basic	16,448	14,736	14,744
Diluted	16,448	14,848	14,841

See accompanying Notes to Consolidated Financial Statements.

F-5

Table of Contents

Petroleum Development Corporation
Consolidated Statements of Cash Flows
(in thousands)

Year Ended December 31,	2009	2008	2007
Cash flows from operating activities:			
Net income (loss)	\$(81,093)	\$ 113,244	\$33,168
Adjustments to net income (loss) to reconcile to net cash provided by operating activities:			
Unrealized (gain) loss on derivatives, net	116,623	(117,536)	4,642
Depreciation, depletion and amortization	131,004	104,640	70,885
Impairment of natural gas and oil properties	926	22,091	1,485
Expired and abandoned leases	7,279	3,633	1,786
Exploratory dry hole costs	1,059	6,504	1,775
Accretion of asset retirement obligation	1,368	1,230	999
Stock-based compensation	5,935	6,702	2,286
Excess tax benefits from stock-based compensation	-	(1,031)	(673)
Loss (gain) from sale of leaseholds/assets	(105)	19	(33,322)
Amortization of debt issuance costs	5,302	1,344	394
Deferred income taxes	(18,084)	59,079	12,201
Changes in current assets and liabilities:			
Decrease (increase) in restricted cash	15,564	(4,257)	(14,254)
Decrease (increase) in accounts receivable	13,197	(9,664)	(16,456)
Decrease (increase) in accounts receivable - affiliates	14,282	(7,631)	(2,302)
Increase (decrease) in income taxes receivable	(27,728)	-	-
Decrease (increase) in other current assets	16,478	(7,855)	6,124
Increase (decrease) in production tax liability	(4,541)	9,857	10,802
Increase (decrease) in accounts payable and accrued expenses	(22,482)	2,790	(10,869)
Increase (decrease) in accounts payable - affiliates	(7,566)	10,282	(3,099)
Increase (decrease) in advances for future drilling contracts	(1,675)	(66,742)	13,645
Increase (decrease) in funds held for future distribution	(22,105)	10,538	7,488
Other	257	1,864	(26,401)
Total changes in current assets and liabilities	(26,319)	(60,818)	(35,322)
Net cash provided by operating activities	143,895	139,101	60,304
Cash flows from investing activities:			
Capital expenditures	(143,033)	(323,153)	(238,988)
Acquisition of oil and gas properties, net of cash acquired	-	-	(255,661)
Decrease (increase) in restricted cash	-	(874)	191,156
Proceeds from sale of leases to partnerships	-	448	1,371
Proceeds from sale of leaseholds/assets	755	538	34,701
Net cash used in investing activities	(142,278)	(323,041)	(267,421)
Cash flows from financing activities:			
Proceeds from credit facility	285,086	419,000	352,000
Proceeds from senior notes	-	200,101	-
Payment of credit facility	(399,586)	(459,500)	(254,000)
Payment of debt issuance costs	(9,249)	(5,571)	(1,468)
Proceeds from sale of equity, net of issuance costs	48,490	-	-
Proceeds from exercise of stock options	-	627	183
Excess tax benefits from stock-based compensation	-	1,031	673

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Contribution from noncontrolling interest	55,000	-	800
Purchase of treasury stock	(364)	(5,549)	(646)
Net cash provided by (used in) financing activities	(20,623)	150,139	97,542
Net decrease in cash and cash equivalents	(19,006)	(33,801)	(109,575)
Cash and cash equivalents, beginning of year	50,950	84,751	194,326
Cash and cash equivalents, end of year	\$31,944	\$50,950	\$84,751

Supplemental cash flow information:

Cash payments for:

Interest, net of capitalized interest	\$32,014	\$19,200	\$9,535
Income taxes, net of refunds	(3,355)	(530)	43,785

Non-cash investing activities:

Change in accounts payable related to purchases of properties and equipment	(36,765)	8,197	32,820
Change in accounts payable - affiliates related to acquisition of partnerships	-	-	668
Change in accounts payable - affiliates related to investment in drilling partnership	-	-	18,712
Change in deferred tax liability resulting from reallocation of acquisition purchase price	-	-	4,188
Change in asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	5,110	1,153	7,850

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

Petroleum Development Corporation
Consolidated Statements of Equity
(in thousands, except share and per share data)

Year Ended December 31,	2009	2008	2007
Common shares, par value \$.01 per share - shares issued:			
Shares at beginning of year	14,871,870	14,907,679	14,834,871
Adjust prior conversion of predecessor shares	-	100	-
Shares issued pursuant to sale of equity	4,312,500	-	-
Exercise of stock options	-	25,699	38,000
Issuance of stock awards, net of forfeitures	79,246	21,863	46,828
Retirement of treasury shares	(21,397)	(83,471)	(12,020)
Shares at end of year	19,242,219	14,871,870	14,907,679
Treasury shares:			
Shares at beginning of year	(7,066)	(5,894)	(4,706)
Purchase of treasury shares	(21,397)	(83,471)	(12,020)
Retirement of treasury shares	21,397	83,471	12,020
Non-employee directors' deferred compensation plan	(1,207)	(1,172)	(1,188)
Shares at end of year	(8,273)	(7,066)	(5,894)
Common shares outstanding	19,233,946	14,864,804	14,901,785
Equity:			
Shareholders' equity			
Preferred shares, \$.01 par:			
Balance at beginning and end of year	\$-	\$-	\$-
Common shares			
Balance at beginning of year	149	149	148
Shares issued pursuant to sale of equity	43	-	-
Issuance of stock awards, net of forfeitures	-	-	1
Balance at end of year	192	149	149
Additional paid-in capital:			
Balance at beginning of year	5,818	2,559	64
Proceeds from sale of equity	48,447	-	-
Issuance of stock awards, net of forfeitures	-	-	(1)
Exercise of stock options	-	627	183
Stock-based compensation expense	5,935	6,702	2,286
Retirement of treasury shares	(364)	(5,101)	(646)
Tax benefit (detriment) of stock-based compensation	(1,630)	1,031	673
Contribution from noncontrolling interest	55,000	-	-
Reclass of noncontrolling interest in PDC Mountaineer, LLC	(48,800)	-	-
Balance at end of year	64,406	5,818	2,559
Retained earnings:			
Balance at beginning of year	505,906	393,044	360,102
Retirement of treasury shares	-	(447)	-
Adoption of new uncertain tax position rule	-	-	(267)
Net income (loss) attributable to shareholders	(79,277)	113,309	33,209
Balance at end of year	426,629	505,906	393,044
Treasury shares, at cost:			
Balance at beginning of year	(292)	(226)	(170)

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Purchase of treasury shares	(364)	(5,549)	(646)
Retirement of treasury shares	364	5,549	646
Non-employee directors' deferred compensation plan	(20)	(66)	(56)
Balance at end of year	(312)	(292)	(226)
Total shareholders' equity	490,915	511,581	395,526
Noncontrolling interests in subsidiary			
Balance at beginning of year	694	759	-
Noncontrolling interest in PDC Mountaineer, LLC	48,800	-	800
Net loss attributed to noncontrolling interest in subsidiary	(1,816)	(65)	(41)
Balance at end of year	47,678	694	759
Total noncontrolling interests in subsidiary	47,678	694	759
Total Equity	\$538,593	\$512,275	\$396,285

See accompanying Notes to Consolidated Financial Statements

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 1 – NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Petroleum Development Corporation ("PDC," "we," "us" or "the Company") is a domestic independent natural gas and oil company engaged in the exploration for and the acquisition, development, production and marketing of natural gas and oil. As of December 31, 2009, we owned an interest in and operated approximately 5,000 gross wells located primarily in the Rocky Mountain Region and Appalachian Basin. We are engaged in two primary business segments: (1) natural gas and oil sales and (2) natural gas marketing.

The consolidated financial statements include the accounts of all wholly-owned subsidiaries and all entities in which we have a controlling financial interest, including a variable interest entity, and our proportionate share of our affiliated partnerships. All material intercompany accounts and transactions have been eliminated in consolidation, including our proportionate share of all significant transactions between us and the limited partnerships.

We determine whether we have a controlling financial interest in an entity by first evaluating whether the entity is a variable interest entity ("VIE") or a voting interest entity. VIEs are entities in which (i) the total equity investment at risk is insufficient to enable the entity to finance itself independently, (ii) the equity holders lack the obligation to absorb expected losses or the right to receive residual returns or (iii) the equity holders have voting rights that are not proportionate to their economic interests. The entity that absorbs the majority of the VIE's losses or receives the majority of the residual returns is considered the primary beneficiary and consolidates the VIE. See Note 13, Noncontrolling Interest in Subsidiaries.

We account for our interests in natural gas and oil limited partnerships under the proportionate consolidation method. Under this method, our consolidated financial statements include our investments in the partnerships recorded by our working interest in each well, thereby accumulating our pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which we participate.

The preparation of our consolidated financial statements in accordance with generally accepted accounting principles in the United States of America ("U.S.") requires us to make estimates and assumptions that affect the amounts reported in our consolidated financial statements and accompanying notes. Actual results could differ from those estimates. Estimates which are particularly significant to our consolidated financial statements include estimates of natural gas and oil sales revenue, natural gas and oil reserves, future cash flows from natural gas and oil properties, valuation of derivative instruments and valuation of deferred income tax assets.

Certain reclassifications have been made to prior period financial statements to conform to the current year presentation, specifically:

- the noncontrolling interest portion of pre-tax expense incurred by and belonging to the minority interest holders of WWWV, LLC was reclassified from depreciation, depletion and amortization ("DD&A") expense to loss attributable to noncontrolling interest (see Note 13, Noncontrolling Interest in Subsidiaries), and
- oil and gas well drilling revenues and costs were reclassified to discontinued operations (see Note 16, Discontinued Operations).

NOTE 2 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash Equivalents

We consider all highly liquid investments with original maturities of three months or less to be cash equivalents.

Restricted Cash

Litigation Settlement. Pursuant to a preliminary court approved litigation settlement agreement reached in October 2008, we funded an escrow account in November 2008 in the amount of \$8.2 million, of which \$5.8 million represented the Company's share of the settlement and the remainder represented the share of our affiliated partnerships for which we serve as the managing general partner. Settlement distribution checks were mailed in July 2009 and as of December 31, 2009, the remaining escrow balance was immaterial. As of December 31, 2008, the current portion of restricted cash included \$8.2 million and accounts receivable from our affiliated partnerships included \$2.4 million related to this settlement.

F-8

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Production Tax Liability Over Withheld. Originating in 2001 and continuing through September 2006, we over withheld estimated production taxes from oil and gas production proceeds. In June 2007, we funded an escrow account in the amount of \$14.1 million for amounts due to the limited partners of our sponsored drilling partnerships for this over withholding. In October 2008, as part of a pre-filing agreement, we paid the Internal Revenue Service ("IRS") on behalf of the limited partners an estimated tax payment of \$4.2 million. In September 2009, we refunded to the limited partners of our sponsored partnerships their share of this over withholding. As of December 31, 2009 and 2008, the current portion of restricted cash included \$2.2 million and \$10.5 million, respectively, including interest, related to this settlement. The remaining balance is for final payment to state taxing authorities and other working interest owners outside of our affiliated partnerships.

Other. We are required by certain government agencies or agreements to maintain bonds or cash accounts for various operating activities. As of December 31, 2009 and 2008, we had collateral in the form of certificates of deposit and cash totaling \$3.1 million and \$2.2 million, respectively, which are reflected in other assets.

Inventory

Inventory consists of oil, stated at the lower of cost to produce or market, and other production supplies intended to be used in our natural gas and oil operations. As of December 31, 2009 and 2008, inventory of \$0.8 million and \$4.3 million, respectively, is included in prepaid expense and other current assets on the balance sheets.

Derivative Financial Instruments

We are exposed to the effect of market fluctuations in the prices of natural gas and oil. Price risk represents the potential risk of loss from adverse changes in the market price of natural gas and oil commodities. We employ established policies and procedures to manage the risks associated with these market fluctuations using commodity derivative instruments. Our policy prohibits the use of natural gas and oil derivative instruments for speculative purposes.

All derivative assets and liabilities are recorded on the balance sheets at fair value. We have elected not to designate any of our derivative instruments as hedges. Classification of realized and unrealized gains and losses resulting from maturities and changes in fair value of open derivatives depends on the purpose for issuing or holding the derivative. Accordingly, changes in the fair value of our derivative instruments are recorded in the statements of operations, with the exception of changes in fair value related to those derivatives we designated to our affiliated partnerships. Changes in the fair value of derivative instruments related to our natural gas and oil sales are recorded in commodity price risk management, net. Changes in the fair value of derivative instruments related to our natural gas marketing segment are recorded in sales from and cost of natural gas marketing. Changes in the fair value of the derivative instruments designated to our affiliated partnerships are recorded on the balance sheets in accounts payable affiliates and accounts receivable affiliates. As positions designated to our affiliated partnerships settle, the realized gains and losses are netted for distribution. Net realized gains are paid to the partnerships and net realized losses are deducted from the partnerships' cash distributions from production. The affiliated partnerships bear their designated share of counterparty risk.

Validation of a contract's fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial

Instruments, for a discussion of our derivative fair value measurements and a summary fair value table of our open positions as of December 31, 2009 and 2008, respectively.

Properties and Equipment

Natural Gas and Oil Properties

We account for our natural gas and oil properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and development dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing natural gas and oil reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved natural gas and oil reserves.

F-9

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Our estimates of proved reserves are based on those quantities of natural gas and oil, which, by analysis of geoscience and engineering data, are estimated with reasonable certainty to be economically producible in the future from known reservoirs, under existing conditions, operating methods, and government regulations. Annually, we engage independent petroleum engineers to prepare reserve and economic evaluations of all our properties on a well-by-well basis as of December 31. Additionally, we adjust our natural gas and oil reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating natural gas and oil reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. Because estimates of reserves significantly affect our DD&A expense, a change in our estimated reserves could have an effect on our net income.

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify our completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful prior to the issuance of the financial statements, the costs incurred, including costs for plugging, prior to the end of the reporting period are expensed to exploration expense and impairment of natural gas and oil properties. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are classified as "suspended well costs" until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time we are able to make a final determination of a well's productive status, the same well is removed from the suspended well status and the proper accounting treatment is recorded. See Note 6, Properties and Equipment, for disclosure related to changes in our capitalized exploratory well costs from January 1, 2007, to December 31, 2009.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved natural gas and oil properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to exploratory expense. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms. Impairment charges are recorded in the statements of operations as a component of exploration expense and impairment of natural gas and oil properties.

The following table presents expiration, impairment and amortization charges recorded for unproved properties.

	2009	2008	2007
	(in thousands)		
Individually significant unproved properties (1)	\$ 3,831	\$ 9,165	\$ 1,484

Insignificant unproved properties	3,448	3,633	1,786
Total	\$ 7,279	\$ 12,798	\$ 3,270

(1) 2008 includes an impairment of \$7.5 million related to our properties in the Fort Worth Basin.

The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

F-10

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

We assess our producing natural gas and oil properties for possible impairment, upon a triggering event, by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of natural gas and oil. Certain events, including but not limited to, downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs, could result in a triggering event and, therefore, a possible impairment of our natural gas and oil properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a future discounted cash flows analysis and is measured by the amount by which the net capitalized costs exceed their fair value.

Upon sale or retirement of significant portions of or complete fields of depreciable or depletable property, the net book value thereof, less proceeds or salvage value, is credited or charged to income. Upon sale of individual wells, the proceeds are credited to accumulated DD&A.

Other Property and Equipment

The following table presents the estimated useful lives of our other property and equipment.

Pipelines and related facilities	10 - 17 years
Transportation and other equipment	3 - 20 years
Buildings	30 - 40 years

Pipelines, Transportation Equipment and Other Equipment. Pipelines, transportation equipment and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over the assets estimated useful lives. We review these long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds our estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset. During 2009, we recognized an impairment of \$0.3 million. No impairments were recorded in 2008 or 2007.

Buildings. Buildings are carried at cost and depreciated on the straight-line method over their estimated useful lives.

Maintenance and repairs on other property and equipment are charged to expense as incurred. Major renewals and improvements are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated DD&A are removed from the accounts, the proceeds are applied thereto and any resulting gain or loss is reflected in income. Total depreciation expense related to other property and equipment was \$8.1 million, \$7.6 million and \$4.3 million in 2009, 2008 and 2007, respectively.

Capitalized Interest

Interest costs are capitalized as part of the historical cost of acquiring assets. Natural gas and oil investments in unproved properties and major development projects, on which DD&A is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready for service. Capitalized interest is calculated by multiplying our weighted-average interest rate on our debt outstanding by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is moved to the DD&A pool, the related capitalized interest is also transferred and is amortized over the useful life of the asset. Interest costs of \$0.8 million, \$2.6 million and \$3 million were capitalized in 2009, 2008 and 2007, respectively.

Production Tax Liability

Production tax liability represents estimated taxes, primarily severance, ad valorem and property, to be paid to the states and counties in which we produce natural gas and oil, including the production of our affiliated partnerships. Our share of these taxes is expensed to natural gas and oil production and well operations costs; the partnerships' share is recognized as a receivable in accounts receivable affiliates on the balance sheets.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Income Taxes

We account for income taxes under the asset and liability method. We recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred tax assets will not be realized, we record a valuation allowance thereby reducing the deferred tax assets to what we consider realizable. As of December 31, 2009, we had recorded a valuation allowance of \$0.7 million. No valuation allowance was recorded at December 31, 2008.

Asset Retirement Obligations

We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the well is completely drilled. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to natural gas and oil production and well operations costs. The initial capitalized costs are depleted over the useful lives of the related assets, through charges to DD&A expense. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations. See Note 9, Asset Retirement Obligations for a reconciliation of the changes in our asset retirement obligation from January 1, 2008, to December 31, 2009.

Retirement of Treasury Shares

We have historically retired all treasury share purchases, with the exception of shares purchased in accordance with our non-employee deferred compensation plan for non-employee directors; see Note 12, Common Stock. As treasury shares are retired, we charge any excess of cost over the par value entirely to additional paid-in-capital, to the extent we have amounts in additional paid-in-capital, with any remaining excess cost being charged to retained earnings.

Revenue Recognition

Natural gas and oil sales. Natural gas and oil sales include the sale of our natural gas and oil produced.

Sales of natural gas are recognized when natural gas has been delivered to a custody transfer point, persuasive evidence of a sales arrangement exists, the rights and responsibility of ownership pass to the purchaser upon delivery, collection of revenue from the sale is reasonably assured and the sales price is fixed or determinable. Natural gas is sold by us under contracts with terms ranging from one month to three years. Virtually all of our contract pricing provisions are tied to a market index, with certain adjustments based on, among other factors, whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, our revenues from the sale of natural gas will suffer if market prices decline and benefit if they increase. We believe that the pricing provisions of our natural gas contracts are customary in the industry.

We currently use the "net-back" method of accounting for transportation arrangements of our natural gas sales. We sell gas at the wellhead and collect a price and recognize revenues based on the wellhead sales price since transportation costs downstream of the wellhead are incurred by the customers and reflected in the wellhead price.

Sales of oil are recognized when persuasive evidence of a sales arrangement exists, the oil is verified as produced and is delivered to a purchaser, collection of revenue from the sale is reasonably assured and the sales price is determinable. We are currently able to sell all the oil that we can produce under existing sales contracts with petroleum refiners and marketers. We do not refine any of our oil production. Our crude oil production is sold to purchasers at or near our wells under short-term purchase contracts at prices and in accordance with arrangements that are customary in the industry.

F-12

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Natural gas marketing. Natural gas marketing is reported on the gross method of accounting, based on the nature of the agreements between Riley Natural Gas ("RNG"), our suppliers and our customers. RNG, our marketing subsidiary, purchases gas from many small producers and bundles the gas together to sell in larger amounts to purchasers of natural gas for a price advantage. RNG has latitude in establishing price and discretion in supplier and purchaser selection. Natural gas marketing revenues and expenses reflect the full cost and revenue of those transactions because RNG takes title to the gas it purchases from the various producers and bears the risks and rewards of that ownership. Both the realized and unrealized gains and losses of the RNG commodity-based derivative transactions for natural gas marketing are included in sales from natural gas marketing or cost of natural gas marketing, as applicable.

Well operations and pipeline income. Well operations and pipeline income are recognized when persuasive evidence of an arrangement exists, services have been rendered, collection of revenues is reasonably assured and the sales price is fixed or determinable. We are paid a monthly operating fee for each well we operate and natural gas transported for outside owners including the limited partnerships we sponsored. The fee covers monthly operating and accounting costs, insurance and other recurring costs. We may also receive additional compensation for special non-recurring activities, such as workovers and recompletions.

Stock-Based Compensation

Stock-based compensation is recognized in our financial statements based on the fair value, on the date of grant or modification, of the equity instrument awarded. Stock-based compensation expense is recognized in the financial statements on a straight-line basis over the vesting period for the entire award. To the extent compensation cost relates to employees directly involved in natural gas and oil acquisitions, exploration and development activities, such amounts may be capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the related cost and expense line item in the statement of operations. No amounts for stock-based compensation were capitalized in 2009, 2008 or 2007.

Earnings Per Share

Basic earnings (loss) per common share ("EPS") is computed by dividing net income (loss), the numerator, by the weighted-average number of common shares outstanding for the period, the denominator. Diluted EPS is similarly computed except that the denominator includes the effect, using the treasury stock method, of our outstanding stock options, unamortized portion of restricted stock and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents a reconciliation of the weighted average diluted shares outstanding.

	2009	2008 (in thousands)	2007
Weighted average common shares outstanding - basic	16,448	14,736	14,744
Dilutive effect of share-based compensation:			
Unamortized portion of restricted stock	-	71	44
Stock options	-	35	48
Non employee director deferred compensation	-	6	5

Weighted average common and common share equivalents outstanding - diluted	16,448	14,848	14,841
---	--------	--------	--------

F-13

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

For 2009, the weighted average common shares outstanding for both basic and diluted were the same, as the effect of dilutive securities were anti-dilutive due to our net loss. The following table presents the weighted average common share equivalents excluded from the calculation of diluted earnings (loss) per share due to their anti-dilutive effect.

	2009	2008 (in thousands)	2007
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive affect:			
Unamortized portion of restricted stock	284	73	18
Stock options	10	-	-
Non employee director deferred compensation	8	-	-
Total anti-dilutive common share equivalents	302	73	18

Recent Accounting Standards

Recently Adopted Accounting Standards

Accounting Standards Codification

In June 2009, the Financial Accounting Standards Board ("FASB") issued the FASB Accounting Standards Codification™ (the "Codification") thereby establishing the Codification as the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with accounting principles generally accepted in the United States of America ("GAAP"). Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative GAAP for Securities and Exchange Commission ("SEC") registrants. The FASB will no longer issue new standards in the form of Statements, FASB Staff Positions, or Emerging Issues Task Force Abstracts; instead, the FASB will issue Accounting Standards Updates. Accounting Standards Updates will not be authoritative in their own right as they will only serve to update the Codification. Effective July 1, 2009, we adopted the Codification. Other than the manner in which new accounting guidance is referenced, the adoption of the Codification did not have a material impact on our financial statements.

Subsequent Events

In May 2009, the FASB issued changes regarding subsequent events, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued. Specifically, the guidance sets forth the period after the balance sheet date during which our management should evaluate events or transactions that may occur for potential recognition or disclosure in our financial statements, the circumstances under which we should recognize events or transactions occurring after the balance sheet date in our financial statements, and the disclosures that we should make about events or transactions that occurred after our balance sheet date. We adopted the guidance as of June 30, 2009. See Subsequent Events below.

Business Combinations

In December 2007, the FASB issued changes regarding the accounting for business combinations. The changes require:

- an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values;
- disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination; and
 - acquisition-related costs to be expensed as incurred.

The changes also amend the accounting for income taxes to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. Further, the changes amend the accounting for income taxes to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

In April 2009, the FASB issued additional changes to the accounting for business combinations. These changes apply to all assets acquired and liabilities assumed in a business combination that arises from contingencies and require:

- an acquirer to recognize at fair value, at the acquisition date, an asset acquired or liability assumed in a business combination that arises from a contingency if the acquisition-date fair value of that asset or liability can be determined during the measurement period; otherwise, the asset or liability should be recognized at the acquisition date if certain defined criteria are met;
- contingent consideration arrangements of an acquiree assumed by the acquirer in a business combination be recognized initially at fair value;
- subsequent measurements of assets and liabilities arising from contingencies be based on a systematic and rational method depending on their nature and contingent consideration arrangements be measured subsequently; and
- disclosures of the amounts and measurements basis of such assets and liabilities and the nature of the contingencies.

The changes above became effective for acquisitions completed on or after January 1, 2009; however, the income tax changes became effective as of that date for all acquisitions, regardless of the acquisition date. We adopted these changes effective January 1, 2009, for which they will be applied prospectively in our accounting for future acquisitions, if any. Upon adoption, we recorded a charge of \$1.5 million to general and administrative expense related to acquisition costs deferred at December 31, 2008.

Consolidation – Noncontrolling Interest in a Subsidiary

In December 2007, the FASB issued changes regarding the nature and classification of the noncontrolling interest in a subsidiary in the consolidated financial statements. The changes require the accounting and reporting for minority interests be recharacterized as noncontrolling interests and classified as a component of equity. Additionally, the changes establish reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners. We adopted these changes effective January 1, 2009. Upon adoption, we reclassified our noncontrolling interest in WWWV, LLC from the mezzanine section, between liabilities and equity, of the balance sheets, to a component of equity, separate from our shareholders' equity.

Fair Value Measurements and Disclosures

In August 2009, the FASB issued changes regarding fair value measurements and disclosures to reduce potential ambiguity in financial reporting when measuring the fair value of liabilities. These changes clarify existing guidance that in circumstances in which a quoted price in an active market for the identical liability is not available, an entity is required to measure fair value using either a valuation technique that uses a quoted price of either a similar liability or a quoted price of an identical or similar liability when traded as an asset, or another valuation technique that is consistent with the principles of fair value measurements, such as an income approach (e.g., present value technique). This guidance also states that both a quoted price in an active market for the identical liability and a quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required are Level 1 fair value measurements. We adopted these changes on October 1, 2009. The adoption did not have a material impact on our financial statements.

In February 2008, the FASB delayed by one year (to January 1, 2009) the fair value measurements and disclosure requirements for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the

financial statements on a recurring basis (at least annually). The January 1, 2009, adoption of the fair value measurements and disclosure requirements for our nonfinancial assets and liabilities did not have a material impact on our financial statements. See Note 3, Fair Value of Financial Instruments.

Derivatives and Hedging Disclosures

In March 2008, the FASB issued changes regarding the disclosure requirements for derivative instruments and hedging activities. Pursuant to the changes, enhanced disclosures are required to provide information about (a) how and why we use derivative instruments, (b) how we account for our derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect our financial position, financial performance and cash flows. We adopted these changes effective January 1, 2009. The adoption did not have a material impact on our financial statements. See Note 4, Derivative Financial Instruments.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Oil and Gas Reserve Estimation and Reporting

In January 2009, the SEC published its final rule regarding the modernization of oil and gas reporting, which modifies the SEC's reporting and disclosure rules for oil and gas reserves. The most notable changes of the final rule include the replacement of the single day period-end pricing to value natural gas and oil reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements were effective for us as of December 31, 2009. Early adoption was not permitted.

In January 2010, the FASB issued changes in its oil and gas reserve estimation and disclosure requirements to align them with the SEC's final rule discussed above. These changes were also effective for us as of December 31, 2009.

We applied the above changes to our financial statements as of and for the year ended December 31, 2009. As a result, our fourth quarter DD&A calculation was based on proved reserves that were calculated using the new SEC reserve reporting guidelines; whereas, DD&A calculations for the first three quarters of 2009 were based on the prior methodology. The impact of using the 12-month average pricing methodology specified under the new SEC reporting rules resulted in an increase of our fourth quarter DD&A expense of approximately \$2.9 million.

Recently Issued Accounting Standards

Consolidation – Variable Interest Entities

In June 2009, the FASB issued changes regarding an entity's analysis to determine whether any of its variable interests constitute controlling financial interests in a variable interest entity. This analysis identifies the primary beneficiary of a variable interest entity as the enterprise that has both of the following characteristics:

- the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance; and
- the obligation to absorb losses of the entity that could potentially be significant to the variable interest entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity.

Additionally, the entity is required to assess whether it has an implicit financial responsibility to ensure that a variable interest entity operates as designed when determining whether it has the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance. The guidance also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. These changes are effective for our financial statements issued for fiscal years beginning after November 15, 2009, with earlier adoption prohibited. We have evaluated the impact that the adoption of these changes will have on our joint venture, consolidated financial statements, related disclosure and management's discussion and analysis. We anticipate that the adoption of these changes will result in deconsolidation of the joint venture on January 1, 2010. Based on the current interpretation of the new guidance, as power over the activities that significantly impact the joint venture is equally shared with our investment partner, we will no longer be considered the primary beneficiary and, hence, will deconsolidate. See Note 13, Noncontrolling Interest in Subsidiaries.

Fair Value Measurements and Disclosures

In January 2010, the FASB issued changes clarifying existing disclosure requirements and requiring gross presentation of activities within the Level 3 roll forward, whereby entities must present separately information about purchases, sales, issuances and settlements. The update also added a new requirement to disclose fair value transfers in and out of Levels 1 and 2 and describe the reasons for the transfers. These changes will be effective for our financial statements issued for the first interim or annual reporting period beginning after December 15, 2009, except for gross presentation of the Level 3 roll forward, which will become effective for annual reporting periods beginning after December 15, 2010.

Subsequent Events

We have evaluated our activities subsequent to December 31, 2009, and have concluded that no material subsequent events have occurred that would require recognition in the financial statements or disclosure in the notes to the financial statements.

F-16

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 3 – FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Financial Instruments

Determination of fair value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 – Quoted prices (unadjusted) in active markets for identical assets or liabilities. Included in Level 1 are our commodity derivative instruments for NYMEX-based natural gas swaps.

Level 2 – Inputs other than quoted prices included within Level 1 that are either directly or indirectly observable for the asset or liability, including (i) quoted prices for similar assets or liabilities in active markets, (ii) quoted prices for identical or similar assets or liabilities in inactive markets, (iii) inputs other than quoted prices that are observable for the asset or liability and (iv) inputs that are derived from observable market data by correlation or other means.

Level 3 – Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Included in Level 3 are our commodity derivative instruments for CIG and PEPL-based natural gas swaps, oil swaps, natural gas and oil collars, physical sales and purchases and our natural gas basis protection derivative instruments.

Derivative Financial Instruments. We measure the fair value of our derivative instruments based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant; therefore, as of December 31, 2009, no adjustment for credit risk was recorded. Validation of our contracts' fair value is performed internally and while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. While we believe these valuation methods are appropriate and consistent with those used by other market participants, the use of different methodologies, or assumptions, to determine the fair value

of certain financial instruments could result in a different estimate of fair value.

F-17

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents, for each hierarchy level, our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of December 31, 2009 and 2008.

	Level 1	Level 3 (in thousands)	Total
As of December 31, 2009			
Assets:			
Commodity based derivatives	\$ 25,598	\$ 36,796	\$ 62,394
Basis protection derivative contracts	-	57	57
Total assets	25,598	36,853	62,451
Liabilities:			
Commodity based derivatives	(3,140)	(9,932)	(13,072)
Basis protection derivative contracts	-	(55,915)	(55,915)
Total liabilities	(3,140)	(65,847)	(68,987)
Net asset (liability)	\$ 22,458	\$ (28,994)	\$ (6,536)
As of December 31, 2008			
Assets:			
Commodity based derivatives	\$ 19,359	\$ 144,644	\$ 164,003
Basis protection derivative contracts	-	33	33
Total assets	19,359	144,677	164,036
Liabilities:			
Commodity based derivatives	(658)	(5,490)	(6,148)
Basis protection derivative contracts	-	(4,338)	(4,338)
Total liabilities	(658)	(9,828)	(10,486)
Net asset	\$ 18,701	\$ 134,849	\$ 153,550

The following table presents a reconciliation of our Level 3 fair value measurements.

	2009	December 31, 2008
	(in thousands)	
Fair value, net asset (liability) beginning of year	\$ 134,849	\$ (2,368)
Changes in fair value included in statement of operations line item:		
Commodity price risk management gain (loss), net	(23,243)	117,243
Sales from natural gas marketing	(380)	257
Cost of natural gas marketing	3,718	(5,017)
Changes in fair value included in balance sheet line item:		
Accounts receivable affiliates	(18,960)	821
Accounts payable affiliates	(29,292)	35,338
Settlements		
Natural gas and oil sales	(95,678)	(11,479)
Natural gas marketing	(8)	54
Fair value, net asset (liability) end of year	\$ (28,994)	\$ 134,849

Changes in unrealized gains (losses) relating to assets (liabilities)
still held as of December 31, 2009, included in statement of
operations line item:

Commodity price risk management gain (loss), net	\$ (38,634)	\$ -
Sales from natural gas marketing	29	2
Cost of natural gas marketing	(1,083)	(1,081)
	\$ (39,688)	\$ (1,079)

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

See Note 4, Derivative Financial Instruments, for additional disclosure related to our derivative financial instruments.

Non-Derivative Financial Assets and Liabilities

The carrying values of the financial instruments comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

The portion of our long-term debt related to our credit facility approximates fair value due to the variable nature of its related interest rate. We have not elected to account for the portion of our long-term debt related to our senior notes under the fair value option; however, we estimate the fair value of this portion of our long-term debt to be \$210.1 million or 103.5% of par value as of December 31, 2009. We determined this valuation based upon measurements of trading activity.

See Note 2 – Summary of Significant Accounting Policies - Property and Equipment, Natural Gas and Oil Properties and - Asset Retirement Obligations for a discussion of how we determined fair value on these obligations.

NOTE 4 – DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for natural gas and oil. To mitigate a portion of our exposure to adverse market changes, we utilize the following economic hedging strategies for each of our business segments.

- For natural gas and oil sales, we enter into derivative contracts to protect against price declines in future periods. While we structure these derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price increases in the physical market.
- For natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical derivatives in our natural gas marketing, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative.

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of December 31, 2009, we had derivative instruments in place for a portion of our anticipated production through 2013 for a total of 56,379,362 MMBtu of natural gas and 1,929,485 Bbls of oil.

As of December 31, 2009, our derivative instruments were comprised of commodity collars and swaps, basis protection swaps and physical sales and purchases.

- Collars contain a fixed floor price (put) and ceiling price (call). If the index price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and index price from the counterparty. If the index price exceeds the fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and index price to the counterparty. If the index price is between the put and call strike price, no payments are due to or from the counterparty.

- Swaps are arrangements that guarantee a fixed price. If the index price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the index price and the fixed contract price from the counterparty. If the index price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the index price and the fixed contract price to the counterparty. If the index price and contract price are the same, no payment is due to or from the counterparty.
- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG-basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract. If the market price and contract price are the same, no payment is due to or from the counterparty.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

- Physical sales and purchases are derivatives for fixed-priced physical transactions where we sell or purchase third party supply at fixed rates. These physical derivatives are offset by financial swaps: for a physical sale the offset is a swap purchase and for a physical purchase the offset is a swap sale.

The following table presents the location and fair value amounts of our derivative instruments on the balance sheets as of December 31, 2009 and 2008.

Derivatives instruments not designated as hedges (1):	Balance sheet line item	Fair Value	
		December 31, 2009	December 31, 2008
(in thousands)			
Derivative Assets: (2)	Current		
	Commodity contracts		
	Related to natural gas and oil sales	Fair value of derivatives \$ 39,107	\$ 112,036
	Related to natural gas marketing	Fair value of derivatives 3,077	4,820
	Basis protection contracts		
	Related to natural gas marketing	Fair value of derivatives 39	25
		42,223	116,881
	Non Current		
	Commodity contracts		
	Related to natural gas and oil sales	Fair value of derivatives 19,680	45,971
	Related to natural gas marketing	Fair value of derivatives 530	1,176
	Basis protection contracts		
	Related to natural gas marketing	Fair value of derivatives 18	8
		20,228	47,155
Total Derivative Assets		\$ 62,451	\$ 164,036
Derivative Liabilities:			
(3)	Current		
	Commodity contracts		
	Related to natural gas and oil sales	Fair value of derivatives \$ (2,451)	\$ -
	Related to natural gas marketing	Fair value of derivatives (2,626)	(4,720)
	Basis protection contracts		
	Related to natural gas and oil sales	Fair value of derivatives (15,127)	-
	Related to natural gas marketing	Fair value of derivatives (4)	(46)

		(20,208)	(4,766)
Non Current			
Commodity contracts			
Related to natural gas and oil sales	Fair value of derivatives	(7,572)	-
Related to natural gas marketing	Fair value of derivatives	(423)	(1,428)
Basis protection contracts			
Related to natural gas and oil sales	Fair value of derivatives	(40,784)	(4,292)
		(48,779)	(5,720)
Total Derivative Liabilities		\$ (68,987)	\$ (10,486)

(1)As of December 31, 2009 and 2008, none of our derivative instruments were designated as hedges.

(2)Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our balance sheets include a corresponding payable to our affiliated partnerships of \$13.4 million and \$37.5 million as of December 31, 2009 and 2008, respectively. Further, December 31, 2009, includes derivative positions owned by our joint venture of \$0.2 million.

(3)Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our balance sheets include a corresponding receivable from our affiliated partnerships of \$21 million and \$1.6 million as of December 31, 2009 and 2008, respectively. Further, December 31, 2009, includes derivative positions owned by our joint venture of \$(1.6) million.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the impact of our derivative instruments on our statements of operations.

Statement of operations line item	2009			2008		
	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
	(in thousands)					
2009:						
Commodity price risk management gain (loss), net						
Realized gains (losses)	\$84,655	\$22,690	\$107,345	\$(549)	\$10,036	\$9,487
Unrealized gains (losses)	(84,655)	(32,743)	(117,398)	549	117,802	118,353
Total commodity price risk management gain (loss), net (1)	\$-	\$(10,053)	\$(10,053)	\$-	\$127,838	\$127,838
Sales from natural gas marketing						
Realized gains (losses)	\$4,798	\$2,724	\$7,522	\$1,447	\$(3,329)	\$(1,882)
Unrealized gains (losses)	(4,798)	1,295	(3,503)	(1,447)	6,061	4,614
Total sales from natural gas marketing(2)	\$-	\$4,019	\$4,019	\$-	\$2,732	\$2,732
Cost of natural gas marketing						
Realized gains (losses)	\$(4,719)	\$3,699	\$(1,020)	\$(898)	\$930	\$32
Unrealized gains (losses)	4,719	(441)	4,278	898	(6,327)	(5,429)
Total cost of natural gas marketing(2)	\$-	\$3,258	\$3,258	\$-	\$(5,397)	\$(5,397)

(1) Represents realized and unrealized gains and losses on derivative instruments related to our natural gas and oil sales.

(2) Represents realized and unrealized gains and losses on derivative instruments related to our natural gas marketing.

NOTE 5 – CONCENTRATION OF RISK

Accounts Receivable. The following table presents the components of accounts receivable, net.

	December 31,	
	2009	2008
	(in thousands)	
Natural gas and oil sales	\$ 19,527	\$ 23,302
Derivative counterparties	12,887	15,083
	10,260	14,352

Joint interest billings		
Natural gas marketing	9,297	16,125
Other	5,068	1,363
Allowance for doubtful accounts	(548)	(537)
Total accounts receivable, net	\$ 56,491	\$ 69,688

Our accounts receivable are primarily from purchasers of our natural gas and oil production, derivative counterparties and other third parties which own working interests in the properties that we operate. Inherent to our industry is the concentration of natural gas and oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. We record an allowance for doubtful accounts for receivables that we estimate to be uncollectible. In making our estimate, we consider, among other things, our historical write-offs and overall creditworthiness of our customers. Further, consideration is given to well production data for receivables related to well operations. It is reasonably possible that our estimate of uncollectible amounts will change periodically. As of December 31, 2009, we had no customers representing 10% or more of our existing accounts receivable balance.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Major Customers. The following table presents the individual customers constituting 10% or more of total revenues.

Customer	Total Revenues Year Ended December 31,					
	2009		2008		2007	
Suncor Energy Marketing, Inc.	18.6	%	0.2	%	0.0	%
Williams Production RMT Company	16.1	%	12.4	%	12.9	%
DCP Midstream, LP	11.9	%	6.6	%	7.1	%
Tepco Crude Oil, LLC	2.1	%	10.8	%	13.5	%

Derivative Counterparties. A significant portion of our liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing natural gas and oil. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. To date, we have had no counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. As of December 31, 2009 and 2008, no valuation allowance was recorded.

The following table presents the counterparties that expose us to credit risk as of December 31, 2009, with regard to our derivative assets.

Counterparty Name	Fair Value of Derivatives (in thousands)
JPMorgan Chase Bank, N.A. (1)	\$ 28,462
BNP Paribas (1)	23,360
Various (2)	10,629
Total	\$ 62,451

(1) Major lender in our credit facility, see Note 8, Long-Term Debt.

(2) Represents a total of 51 counterparties, includes 5 lenders in our credit facility.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 6 – PROPERTIES AND EQUIPMENT

	December 31, 2009	2008
	(in thousands)	
Properties and equipment, net:		
Natural gas and oil properties (successful efforts method of accounting)		
Proved	\$ 1,329,666	\$ 1,169,969
Unproved	38,626	32,768
Total natural gas and oil properties	1,368,292	1,202,737
Pipelines and related facilities	38,202	33,165
Transportation and other equipment	33,624	31,565
Land and buildings	14,699	14,359
Construction in progress	9,131	76,863
	1,463,948	1,358,689
Accumulated DD&A	(455,755)	(325,611)
	\$ 1,008,193	\$ 1,033,078

Suspended Well Costs

The following table presents the capitalized exploratory well costs pending determination of proved reserves and included in properties and equipment on the balance sheets.

	2009	2008	2007
	(in thousands, except for number of wells)		
Beginning balance at January 1	\$ 1,180	\$ 2,300	\$ 765
Additions to capitalized exploratory well costs pending the determination of proved reserves	10,226	15,644	3,953
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(9,914)	(10,259)	(878)
Capitalized exploratory well costs charged to expense	(318)	(6,505)	(1,540)
Ending balance at December 31	\$ 1,174	\$ 1,180	\$ 2,300
Number of wells pending determination at December 31	2	6	3

As of December 31, 2009, neither of the two suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year after the completion of drilling.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 7 - INCOME TAXES

The table below presents the components of our tax expense from continuing operations for the years presented.

	2009	2008	2007
	(in thousands)		
Current:			
Federal	\$ (27,985)	\$ 3,907	\$ 3,533
State	353	(3,897)	771
Total current income taxes	(27,632)	10	4,304
Deferred:			
Federal	(13,252)	55,500	11,074
State	(4,832)	3,579	1,127
Total deferred income taxes	(18,084)	59,079	12,201
Total income tax provision (benefit)	\$ (45,716)	\$ 59,089	\$ 16,505

For the years ended December 31, 2009, 2008 and 2007, we utilized income tax elections to currently expense approximately \$80 million, \$30 million and \$44 million, respectively, of intangible drilling costs ("IDC"). This election substantially reduced our current tax expense, resulting in a correspondingly higher deferred tax expense. The 2009 IDC deduction resulted in a taxable net operating loss ("NOL"). The Worker, Homeownership, and Business Assistance Act of 2009 increased the statutory NOL carry-back period for losses incurred in 2008 and 2009 tax years for up to five years. This enabled us to utilize our current year NOL to generate an estimated \$26 million refund of federal tax from our 2005 and 2006 tax years.

The following table presents a reconciliation of the statutory rate to our effective tax rate.

	2009		2008		2007	
Statutory tax rate	35.0	%	35.0	%	35.0	%
State income tax, net	3.3	%	3.1	%	3.5	%
Percentage depletion	0.5	%	-0.7	%	-1.5	%
Domestic production activities deduction	-		-0.1	%	-0.8	%
Other, including discrete items (1)	-2.8	%	-2.2	%	2.6	%
	36.0	%	35.1	%	38.8	%

(1) 2009 consists primarily of non-deductible expenditures related to the joint venture; 2008 consists primarily of a discrete tax benefit realized upon the implementation of state tax strategies during the first half of 2008; and 2007 consists primarily of non-deductible penalties.

The Domestic Production Activities Deduction under Section 199 of the Internal Revenue Code, which provides for a phased-in deduction related to qualifying production activities, was provided for the first time under the American Jobs Creation Act of 2004. We recorded an income tax benefit for certain qualifying production activities of approximately \$0.2 million in 2008 and \$0.4 million in 2007. Due to our taxable loss position in 2009 and the resulting NOL carry-back, no Section 199 benefit was recorded in 2009 and our 2005 benefit of \$0.4 million was

reversed. The reversal of the prior year's Section 199 deduction was a detriment to the 2009 effective tax rate and was recorded as a discrete item and is included in "Other" in the above table.

F-24

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2009 and 2008, are presented below.

	2009	2008
	(in thousands)	
Deferred tax assets:		
Allowance for lease impairment	\$ 5,751	\$ 4,910
Provision for underpayment of natural gas sales	1,130	-
Deferred revenue related to cash withheld for future plugging cost	715	1,043
Deferred compensation	3,277	2,846
Asset retirement obligations	5,189	8,519
Employee benefits	537	547
State NOL, tax credits and deduction carryforward, net	4,664	309
Percentage depletion - carryforward	811	-
Other	405	289
Total gross deferred tax assets	22,479	18,463
Less valuation allowance	(747)	-
Deferred tax assets	21,732	18,463
Deferred tax liabilities:		
Properties and equipment	(170,161)	(165,212)
Investment in PDC Mountaineer, LLC	(23,935)	-
Unrealized gains - derivatives	(230)	(44,199)
Future state liabilities	(270)	-
Total gross deferred tax liabilities	(194,596)	(209,411)
Net deferred tax liability	\$ (172,864)	\$ (190,948)
Classification in the Consolidated Balance Sheets:		
Prepaid expenses and other current assets	\$ 5,148	\$ (28,355)
Deferred income taxes	(178,012)	(162,593)
Net deferred tax liability	\$ (172,864)	\$ (190,948)

Deferred tax liabilities for properties and equipment increased in 2009 and 2008, primarily as a result of our election to expense \$80 million and \$30 million, respectively, of IDC for income tax purposes. The 2009 increase was partially offset by the contribution of natural gas and oil properties to our joint venture. In total, deferred tax liabilities decreased in 2009 due to the substantial reduction in unrealized gains on derivatives.

Included in deferred tax assets at December 31, 2009, were unutilized net tax benefits totaling \$4.7 million related to state NOL, state tax credit and state deduction carry-forwards. Approximately half of this deferred tax asset will expire through December 2021, and the remaining amount will expire through 2029.

In assessing whether a valuation allowance for the deferred tax assets should be recorded, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of

deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible or tax credits become utilizable. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible or utilizable, we have recorded a \$0.7 million valuation allowance related to certain state tax benefit carry-forwards. The amount of the remaining deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carry-forward period are reduced.

F-25

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

In 2007, upon the adoption of accounting guidance related to uncertain tax positions, we reduced retained earnings by \$0.3 million, deferred income taxes payable by \$0.9 million, increased current income taxes payable by \$0.2 million and the liability for unrecognized tax benefit by \$1 million.

The following table presents a reconciliation of the total amounts of unrecognized tax benefits.

	2009	December 31, 2008 (in thousands)	2007
Balance beginning of year	\$ 1,271	\$ 888	\$ 952
Additions for tax positions of prior years	43	216	819
Additions for tax positions of current year	7	167	-
Reductions for tax positions of prior years	-	-	(883)
Reductions due to settlements	(406)	-	-
Reductions due to lapse of statute of limitations	(349)	-	-
Balance end of year	\$ 566	\$ 1,271	\$ 888

Interest and penalties related to uncertain tax positions are recognized in income tax expense. Accrued interest and penalties related to uncertain tax positions were immaterial for each of the years in the three-year period ended December 31, 2009. The total amount of unrecognized tax benefits that would affect the effective tax rate, if recognized, is \$0.6 million as of December 31, 2009 and \$0.9 million as of December 31, 2008. As of December 31, 2009, it is reasonably possible that the total amount of unrecognized tax benefit could decrease up to \$0.6 million in the next twelve months due to the conclusion of the current IRS examination and the lapse of an applicable statute of limitation.

For federal tax purposes, the statute of limitations is open for tax years 2005 and forward. The statute of limitation for most of our state tax jurisdictions is open from 2004 forward.

NOTE 8 - LONG-TERM DEBT

Long-term debt consists of the following:

	2009	December 31, 2008 (in thousands)
Credit facility	\$ 80,000	\$ 194,500
12% Senior notes due 2018, net of discount of \$2.3 million	200,657	200,367
Total long-term debt	\$ 280,657	\$ 394,867

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Credit facility

We have a credit facility co-arranged by JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, dated as of November 4, 2005, as amended last on December 18, 2009 ("the Eighth Amendment"), with an aggregate revolving commitment of \$305 million. The credit facility, through the series of amendments, includes commitments from: Bank of America, N.A.; Calyon New York Branch; Bank of Montreal; The Royal Bank of Scotland plc; The Bank of Nova Scotia; Wachovia Bank, N.A.; Guaranty Bank, FSB; Texas Capital Bank; Bank of Oklahoma; U.S. Bank National Association; and Compass Bank. The maximum allowable commitment under the current credit facility is \$500 million. The credit facility is subject to and collateralized by our natural gas and oil reserves, exclusive of the joint ventures natural gas and oil reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. Our credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of our reserves at December 31st and June 30th, respectively; additionally, we or our lenders may request a redetermination upon the occurrence of certain events. A commodity price deck reflective of the current and future commodity pricing environment, as determined by our lenders, is utilized to quantify our reserves used in the borrowing base calculation and thus determines the underlying borrowing base. As of December 31, 2009, our aggregate revolving commitment was secured by substantially all of our natural gas and oil properties.

We are required to pay a commitment fee of 0.5% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JP Morgan's prime rate, a secondary market rate of a three-month certificate of deposit plus 1%, one month LIBOR plus 1% or the federal funds effective rate plus 0.5%. ABR and adjusted LIBOR borrowings are assessed an additional margin spread based upon the outstanding balance as a percentage of the available balance. ABR borrowings are assessed an additional margin of 1.375% to 2.375%. Adjusted LIBOR borrowings are assessed an additional margin spread of 2.25% to 3.25%. Any debt issuance costs are capitalized and amortized using the effective interest rate method over the remaining term of the credit facility. As a result of our 2009 redeterminations, we expensed \$2 million of debt issuance cost as a result of reductions in our borrowing base and changes in lenders. As of December 31, 2009, we had \$6.2 million in debt issuance costs being amortized at a rate of \$0.7 million per quarter. No principal payments are required until the credit agreement expires on May 22, 2012, or in the event that the borrowing base would fall below the outstanding balance.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, and (g) engage in hedging activities unless certain requirements are satisfied. The credit facility also requires us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. Further, we are required to comply with certain financial tests and maintain certain financial ratios on a quarterly basis. The financial tests and ratios include requirements to: (a) maintain a minimum current ratio, as defined per credit facility, of 1.00 to 1.00 and (b) not to exceed a maximum leverage ratio of 4.25 to 1.00 through December 31, 2010, 4.00 to 1.00 through June 30, 2011, and 3.75 to 1.00 thereafter.

In August 2009, we issued a \$18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider to secure the construction of certain additions and/or replacements to its facilities to provide firm transportation of the natural gas produced by us and others for whom we market their production in the West Virginia

and Southwestern Pennsylvania areas. The letter of credit reduces the amount of available funds under our credit facility by an equal amount. We pay a fronting fee of 0.25% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.5% as of December 31, 2009) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

In October 2009, our credit facility was amended to, among other things, permit the contribution of certain natural gas and oil properties in the Appalachian Basin, to the joint venture, facilitate other aspects of the joint venture and permit us to make additional investments in the joint venture so long as certain conditions are satisfied. Until our investor partner earns a 50% interest in the joint venture, such additional investments are limited to \$40 million. Concurrently with our contribution of certain natural gas and oil properties to the joint venture, our borrowing base under the credit facility was reduced from \$350 million to \$305 million upon the execution of the joint venture agreement and the contribution of our natural gas and oil properties in the Appalachian Basin to the joint venture. Our November 2009 redetermination, which reaffirmed our borrowing base at \$305 million, was completed in December 2009. See Note 13, Noncontrolling Interest in Subsidiaries.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

As of December 31, 2009, we had drawn \$80 million from our credit facility compared to \$194.5 million as of December 31, 2008. The borrowing rate on the outstanding balance was 4.7% as of December 31, 2009, compared to 4.6% as of December 31, 2008. As of December 31, 2009, the available funds under our credit facility were \$206.3 million. We were in compliance with all covenants at December 31, 2009, and expect to remain in compliance throughout the next year.

12% Senior Notes Due 2018

In February 2008, we issued 12% senior notes with a total principal amount of \$203 million payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15. The senior notes were issued at a discount, 98.572% of the principal amount. We incurred \$5.4 million in costs associated with the issuance of the debt which was capitalized as a deferred loan cost. The original discount and the deferred note costs are being amortized to interest expense over the term of the debt using the effective interest method.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. Additionally, we are subject to two incurrence covenants: 1) earnings before interest, taxes, DD&A expense and capital expenditures ("EBITDAX") of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants as of December 31, 2009, and expect to remain in compliance throughout the next year.

The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if:

- a subsidiary is a guarantor under our senior credit facility; and
- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture. As of December 31, 2009, none of our subsidiaries were obligated as guarantors of our senior notes.

The indenture provides that at any time, which may be more than once, before February 15, 2011, we may redeem up to 35% of the outstanding notes with proceeds from one or more equity offerings at a redemption price of 112% of the principal amount of the notes redeemed, plus accrued and unpaid interest, as long as:

-

at least 65% of the aggregate principal amount of the notes issued on February 8, 2008, remains outstanding after each such redemption; and

- the redemption occurs within 180 days after the closing of the equity offering.

The notes also provide that we may, at our option, redeem all or part of the notes at any time prior to February 15, 2013, at the make-whole price set forth in the indenture, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption. Further, the indenture provides that upon a change of control, we must give holders of the notes the opportunity to put their notes to us for repurchase at a repurchase price of 101% of the principal amount, plus accrued and unpaid interest.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 9 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interest in natural gas and oil properties.

	2009	2008
	(in thousands)	
Balance at beginning of year	\$ 23,086	\$ 20,781
Obligations assumed with development activities and acquisitions	883	1,189
Obligations discharged with disposal of properties and asset retirements	(52)	(114)
Accretion expense	1,368	1,230
Revisions in estimated cash flows	4,279	-
Balance at end of year	29,564	23,086
Less current portion	(250)	(50)
Long-term portion	\$ 29,314	\$ 23,036

If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost.

NOTE 10 - EMPLOYEE BENEFIT PLANS

We sponsor a qualified retirement plan covering substantially all of our employees. The plan consists of a 401(k) component and a profit sharing component. The 401(k) component enables eligible employees to contribute a portion of their compensation through pre-tax payroll deductions in accordance with specific guidelines. We provide a discretionary matching contribution based on a percentage of the employees' contributions up to certain limits. Our contribution to the profit sharing component is discretionary. Our total combined expense for both 401(k) and profit sharing in 2009, 2008 and 2007, was \$1.7 million, \$1.9 million and \$1.4 million, respectively.

We provide a supplemental retirement benefit of deferred compensation under terms of the various employment agreements with certain executive officers. During 2009, 2008 and 2007, we charged \$0.3 million, \$0.2 million and \$0.4 million, respectively, related to this plan to general and administrative expenses. As of December 31, 2009 and 2008, the liability related to this benefit was \$2.4 million, which was included in other liabilities on the balance sheets, with the exception of \$0.3 million included in other accrued expenses as of December 31, 2009.

We offer a supplemental healthcare benefit covering certain former executive officers and their spouses in accordance with each officer's employment agreement. Expenses incurred during 2009, 2008 and 2007 related to this plan were immaterial. As of December 31, 2009 and 2008, included in other liabilities on the balance sheets was a related liability of \$0.5 million and \$0.6 million, respectively.

We maintain a non-qualified deferred compensation plan for our non-employee directors. The amount of compensation deferred by each participant is based on participant elections. The amounts deferred pursuant to the plan are invested in our common stock, maintained in a rabbi trust and are classified in the balance sheets as treasury shares as a component of shareholders' equity. The plan may be settled in either cash or shares as requested by the

participant. As of December 31, 2009 and 2008, the liability related to this plan was \$0.2 million, which was included in other liabilities on the balance sheets.

NOTE 11 - COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements

In connection with the acquisition of natural gas and oil properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells on the acquired acreage in Pennsylvania by January 2016. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of \$25,000 per undrilled well for a total contingent obligation of \$2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of December 31, 2009, we have drilled 28 wells pursuant to this agreement.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

In September 2008, we entered into a pipeline and processing plants expansion agreement with an unrelated party, who is currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we agreed to make a capital investment of \$60 million, for our own benefit, over a three-year period commencing on January 1, 2009, to develop or facilitate production in our Wattenberg Field dedicated to this purchaser and, if the purchaser failed to diligently proceed with the pipeline and processing plants, we would be relieved of our obligations under the agreement. In March 2009, we received from the unrelated party a notice waiving our commitment and stating that the pipeline and processing plant expansions were either on hold or had been delayed. The waiver relieves us of the \$60 million capital investment obligation.

Firm Transportation Agreements

We have entered into contracts that provide firm transportation, sales and processing charges on pipeline systems through which we transport or sell our natural gas and the natural gas of other companies, working interest owners and our affiliated partnerships. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volumes requirements include volumes produced by us, volumes purchased from third parties, volumes produced by our joint venture and affiliated partnerships. As of December 31, 2009, based on a review of our drilling plans and volume projections, we do not expect to meet all future volume requirements for a firm transportation agreement in our Piceance Basin. Accordingly, during the fourth quarter of 2009, we recorded a charge to natural gas and oil production and well operation costs of \$2.7 million and a corresponding liability, which is included in other liabilities on the balance sheet. We are currently working with the third party to renegotiate the terms and timing of our volume requirements under this agreement. If we are not able to renegotiate this agreement or meet all future volume requirements, the result may be additional significant charges to natural gas and oil production and well operations costs.

The following table presents gross volume information related to our long-term firm sales, processing and transportation agreements for pipeline capacity. These agreements require a demand charge whether volumes are delivered or not. We record in our financial statements only our share of costs based upon our working and net revenue interest in the wells. If the volumes below are not met, we will bear all costs related to the volume shortfall.

Area	Year Ending					2014 Through Expiration	Expiration Date
	2010	2011	2012	2013	2014		
Volume (MMBtu)							
Appalachian Basin (1)	803,900	591,300	4,106,120	10,993,800	94,965,560	August 2022	
Grand Valley	31,780,021	32,288,245	32,785,874	30,458,110	96,725,834	May 2021	
NECO	1,825,000	-	-	-	-	December 2010	
NECO	1,825,000	1,825,000	1,825,000	1,825,000	5,475,000	December 2016	
Dollar commitment (in	\$ 18,483	\$ 17,979	\$ 20,046	\$ 22,397	\$ 100,979		

thousands)

(1) Includes a precedent agreement that becomes effective when the planned pipeline is placed in service, currently estimated to be 2012. This agreement will be null and void if the pipeline is not completed. In August 2009, we issued a letter of credit related to this agreement, see Note 8, Long-Term Debt.

F-30

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Litigation

We are involved in various legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that we have properly accrued reserves.

Royalty Owner Class Actions

Glen Droegemueller v. Petroleum Development Corporation, Case No. 1:07-C-436 in the U.S. District Court, Weld County, Colorado, filed May 29, 2007

Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company alleging that we underpaid royalties on natural gas produced from wells operated by us in parts of the State of Colorado. The plaintiff sought declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007. On October 10, 2008, the court preliminarily approved a settlement agreement between the plaintiffs and the Company, on behalf of itself and the partnerships for which the Company is the managing general partner. Based on the settlement terms, the settlement amount payable by the Company is \$5.8 million. Such moneys, in addition to moneys related to the settlement on behalf of the partnerships, were deposited in an escrow account on November 3, 2008. The final settlement was approved by the court on April 7, 2009. Settlement distribution checks were mailed in July 2009.

Beymer v. Petroleum Development Corporation and Riley Natural Gas Company, Case No. 2:09-C-3 in U. S. District Court, Northern District of West Virginia, filed on January 21, 2009, and

Gobel et al v. Petroleum Development Corporation, Case No. 09-C-40 in U. S. District Court, Northern District of West Virginia, filed on January 27, 2009

Joe L. Beymer and Georgia F. Beymer, individually and as representative of the class of all similarly situated individuals and entities, filed a lawsuit against the Company alleging that we failed to properly pay royalties (the "Beymer lawsuit"). The allegations state that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages are requested in addition to breach of contract, tort, and fraud allegations. A second suit was filed in West Virginia state court in Harrison County by David W. Gobel alleging a class action with allegations similar to those alleged in the Beymer lawsuit. Both cases have been removed to federal court in the Northern District of West Virginia. The Beymer suit was subsequently voluntarily dismissed by plaintiff's counsel. Initial mediation was commenced in January 2010. Although such removal has been contested, the case is currently stayed as the parties exchange information and investigate settlement.

Other

In July 2008, the Company self-reported to the Colorado Department of Public Health and Environment (the "CDPHE") certain non-compliance with air laws at its Logan Master Meter Station. The CDPHE subsequently initiated a review and inspection of air compliance at its Logan Master Meter Station. On November 18, 2009, and December 19, 2009, the Company received related compliance advisories for alleged non-compliance. On February 19, 2010, the Company received a letter from the CDPHE with a proposed settlement for this matter of \$0.2 million. The Company has entered negotiations with the CDPHE regarding this assessment.

On December 8, 2008, we received a Notice of Violation/Cease and Desist Order (the "Notice") from the Colorado Department of Public Health and Environment, related to the stormwater permit for the Garden Gulch Road. The Company manages this private road for Garden Gulch LLC. The Company is one of eight users of this road, all of which are natural gas and oil companies operating in the Piceance region of Colorado. Operating expenses, including this fine, if any, are allocated among the eight users of the road based upon their respective usage. The Notice alleges a deficient and/or incomplete stormwater management plan, failure to implement best management practices and failure to conduct required permit inspections. The Notice requires corrective action and states that the recipient shall cease and desist such alleged violations. The Notice states that a violation could result in civil penalties up to \$10,000 per day. The Company's responses were submitted on February 6, 2009, and April 8, 2009. Given the inherent uncertainty in administrative actions of this nature, the Company is unable to predict the ultimate outcome of this administrative action at this time.

We are involved in various other legal proceedings that we consider normal to our business. Although the results cannot be known with certainty, we believe that the ultimate results of such proceedings will not have a material adverse effect on our financial position, results of operations or liquidity.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Partnership Repurchase Provision

Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions from production), if repurchase is requested by investors, subject to our financial ability to do so. As of December 31, 2009, the maximum annual repurchase obligation, based upon the minimum price described above, was approximately \$9.4 million. We believe we have adequate liquidity to meet this obligation. During 2009, 2008 and 2007, we paid \$1.7 million, \$1.8 million and \$1.6 million, respectively, under this provision for the repurchase of partnership units.

Performance Supplements

Our drilling programs formed from 1999 through the second quarter of 2005 contain a performance supplement that provides for changes in the distribution of partnership profits if certain levels of performance are not met. The terms of this provision in the partnership agreements are not a guarantee of a rate of return on an investment in the partnership. Under those specific conditions, such changes can result in our share of an affected partnership's profits being reduced by up to one half of the amount to which we otherwise would be entitled in the affected period. In no event would we be obligated to assume a disproportionate share of losses in such partnerships; should the partnerships that contain this provision in the partnership agreements incur a loss, our share of such losses would be unaffected by the terms of this provision. In accordance with these provisions, our share of partnership profits was reduced by an aggregate of \$0.8 million, \$1 million and \$0.6 million during 2009, 2008 and 2007, respectively. As of December 31, 2009 and 2008, based on production through December 31 of the corresponding year, amounts accrued were immaterial.

Lease Agreements

We entered into operating leases principally for the leasing of natural gas compressors, office space in Denver and Bridgeport, and general office equipment. The following table presents the minimum future lease payments under the non-cancelable operating leases as of December 31, 2009.

Year	(in thousands)
2010	\$ 2,001
2011	1,431
2012	991
2013	886
2014	863
Thereafter	645
	\$ 6,817

Operating lease expense for the years ended December 31, 2009, 2008 and 2007, was \$2.3 million, \$2.5 million and \$1.5 million, respectively.

Employment Agreements with Executive Officers

We have employment agreements with our Chief Executive Officer, Chief Financial Officer, Chief Accounting Officer and other executive officers. The employment agreements provide for annual base salaries, eligibility for performance bonus compensation and other various benefits, including retirement and termination benefits.

F-32

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

In the event of termination following a change of control of the Company, or where the Company terminates the executive officer without cause or where an executive officer terminates employment for good reason, the severance benefits range from two times to three times the sum of his highest annual base salary during the previous two years of employment immediately preceding the termination date and his highest annual bonus received during the same two year period. For this purpose a "change of control" corresponds to the definition of "change of control" under Section 409A of the Internal Revenue Code of 1986 (IRC) and the supporting treasury regulations. The executive officer is also entitled to (i) vesting of any unvested equity compensation (excluding all long-term incentive performance shares), (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of any earned and unpaid bonus amounts. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated.

In the event that an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and to provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

In the event that an executive officer voluntarily terminates his employment for other than good reason, he is entitled to receive (i) his base salary, bonus and incremental retirement payment prorated for the portion of the year that the executive officer is employed by the Company, provided, however, that with respect to the bonus, for certain executive officers, there shall be no proration of the bonus if such executive leaves prior to the last day of the year and, with respect to the remaining executive officers, there shall be no proration of the bonus in the event such executive officer leaves prior to March 31 in the year of his termination, (ii) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted, (iii) any unpaid expense reimbursement upon presentation by the executive officer of an accounting of such expenses in accordance with our normal practices, and (iv) any other payments for benefits earned under the employment agreement or our plans.

In the event of death or disability, the executive is entitled to receive certain benefits. For this purpose, the definition of "disability" corresponds to the definition under IRC 409A and the supporting treasury regulations. The benefits shall be payable in a lump sum and shall be equal to the compensation and other benefits that would otherwise have been paid for a six-month period following the termination date plus a pro-rated portion of the performance bonus.

Derivative Contracts

We would be exposed to natural gas and oil price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. We have had no counterparty default losses.

Partnership Casualty Losses

As Managing General Partner of 33 partnerships, we have liability for potential casualty losses in excess of the partnership assets and insurance. We believe the casualty insurance coverage that we and our subcontractors carry is adequate to meet this potential liability.

NOTE 12 - COMMON STOCK

Sale of Equity Securities

In August 2009, we sold 4,312,500 shares of our common stock in an underwritten public offering at a price of \$12.00 per share. We used the net proceeds of \$48.5 million to pay down our credit facility and for general corporate purposes. The offering was made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on November 26, 2008, and declared effective on January 30, 2009.

F-33

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Stock-Based Compensation Plans

As approved by the shareholders in June 2004, we maintain a long-term equity compensation plan for our officers and certain key employees (the "2004 Plan"). In accordance with the plan, awards may be issued in the form of stock options, stock appreciation rights, restricted stock or performance shares. Awards pursuant to the plan vest over periods set at the discretion of the Compensation Committee of our Board of Directors ("Board") and, with regard to options, have a maximum exercisable period of ten years. We also maintain a restricted stock plan for our non-employee directors ("Non-Employee Director Plan"), approved by the shareholders in June 2005.

The following table presents summary data related to our outstanding stock-based compensation plans.

	2004 Plan				Non-Employee Director Plan			
	Statement of Operations Impact				Statement of Operations Impact			
	Shares	Income		Net Impact	Shares	Income		Net Impact
Stock-Based Compensation		Tax Benefit	Stock-Based Compensation			Tax Benefit		
	(in thousands)				(in thousands)			
Shares reserved for award	750,000				100,000			
Awards granted, net of forfeitures								
2009 (1)	158,422	\$5,194	\$(1,993)	\$3,201	32,700	\$741	\$(284)	\$457
2008 (2)	149,049	5,725	(2,184)	3,541	14,000	977	(373)	604
2007	96,718	2,003	(773)	1,230	12,710	283	(109)	174
2006 and prior	184,298				13,446			
Total awards granted	588,487				72,856			
Remaining shares available for award	161,513				27,144			

(1) Includes a total of \$1.7 million related to agreements with our former executive vice president and chief executive officer.

(2) Includes a total of \$2.6 million related to agreements with our former president and chief executive officer.

Stock Option Awards

We have granted stock options pursuant to various stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. We have not issued any new stock options awards since 2006. For the year ended December 31, 2009, pursuant to an agreement with a former executive vice president, we accelerated the vesting schedule for 1,094 options, all of which vested pursuant to the original terms of the awards. For the year ended December 31, 2008, pursuant to agreements with our former president and our former chief executive officer, we modified options to purchase 9,905 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

The following table presents the changes in our stock option awards for the year ended December 31, 2009.

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (years)
Outstanding at December 31, 2008	18,351	\$ 41.68	6.8
Forfeited	(8,045)	41.39	
Outstanding at December 31, 2009	10,306	41.90	6.0
Vested and expected to vest at December 31, 2009	10,306	41.90	6.0
Exercisable at December 31, 2009	8,591	41.42	5.9

F-34

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

	As of/For the Year Ended December 31,		
	2009	2008	2007
(in thousands, except market price)			
Total intrinsic value of options exercised	\$ -	\$ 659	\$ 1,691
Total intrinsic value of options outstanding	-	-	1,319
Total intrinsic value of options exercisable	-	-	971
Market price per common share as of December 31	18.21	24.07	59.13

The options outstanding and exercisable at December 31, 2009 and 2008, had no intrinsic value as the exercise price of the options exceeded the closing market price of our common stock at the respective dates. Total compensation cost related to stock options granted and not yet recognized in our statement of operations as of December 31, 2009, was immaterial.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, generally over four years, and five years in connection with a one-time grant to executive officers in March 2008. Time-based awards for non-employee directors generally vest on July 1 of the year following the date of the grant.

The following table presents the changes in non-vested time-based awards for the year ended December 31, 2009.

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2008	218,060	\$ 52.59
Granted	210,548	14.02
Vested	(105,032)	50.88
Forfeited	(18,248)	36.36
Non-vested at December 31, 2009	305,328	\$ 27.55

	As of/For the Year Ended December 31,		
	2009	2008	2007
(in thousands, except per share data)			
Total intrinsic value of time-based awards vested	\$ 1,731	\$ 6,710	\$ 2,208
Total intrinsic value of time-based awards non-vested	5,560	5,249	10,161
Market price per common share as of December 31	18.21	24.07	59.13

Weighted average grant date fair value per share	14.02	57.64	48.09
---	-------	-------	-------

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our statements of operations as of December 31, 2009, was \$6.4 million. This cost is expected to be recognized over a weighted average period of 2.3 years. For the year ended December 31, 2009, pursuant to an agreement with a former executive vice president, we accelerated time-based awards to vest 30,875 shares, all of which would have vested pursuant to the original terms of the award. For the year ended December 31, 2008, pursuant to agreements with our former president and our former chief executive officer, we modified time-based awards to vest 24,024 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award, resulting in an increase in the original fair value of \$0.4 million.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily three years. Generally, the market-based shares vest if the participant is continuously employed throughout the performance period and certain per share price thresholds are attained as of the last day of each performance period, with a maximum vesting period of five years. All compensation cost related to the market-based awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved. For the year ended December 31, 2009, pursuant to an agreement with a former executive vice president, 21,263 shares were forfeited. For the year ended December 31, 2008, pursuant to agreements with our former president and our former chief executive officer, we modified market-based awards to vest 38,979 shares by accelerating the vesting schedule, none of which would have vested pursuant to the original terms of the award. The incremental change in fair value per share of the modified awards was immaterial.

The weighted average grant date fair value per market-based share, including shares modified in 2008 pursuant to agreements with our former president and our former chief executive officer, was computed using the Monte Carlo pricing model using the weighted average assumptions presented in the table below.

	Year Ended December 31,					
	2009		2008		2007	
Expected term of award	3 years		3 years		3 years	
Risk-free interest rate	2.0	%	2.7	%	4.7	%
Volatility	59.0	%	45.6	%	44.0	%
Weighted average grant date fair value per share	\$ 6.47		\$ 43.61		\$ 36.07	

For 2009, expected volatility was based on a blend of our historical and implied volatility and, for 2008, was based on our historical volatility. The expected lives of the awards were based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant or modification and extrapolated to approximate the life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

The following table presents the changes in non-vested market-based awards for 2009.

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2008	72,683	\$ 41.62
Granted	28,130	6.47
Forfeited	(21,263)	29.15
Non-vested at December 31, 2009	79,550	\$ 32.52

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our statement of operations as of December 31, 2009, was \$0.4 million. This cost is expected to be recognized over a weighted average period of 1.2 years.

Treasury Share Purchases

Treasury shares purchased pursuant to our non-employee director deferred compensation plan are purchased in the open market at fair value and held in a rabbi trust.

Pursuant to our stock-based compensation plans, we purchase shares from employees for their payment of tax liabilities related to the vesting of securities. Shares are purchased at fair market value based on the closing price on the date of purchase and subsequently retired.

F-36

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

In 2006, our Board approved a purchase program authorizing us to purchase up to 10% (1,477,109 shares) of our then outstanding common stock through April 2008. Stock purchases under this program were made in 2007 and 2008 in the open market or in private transactions, at times and in amounts that we deem appropriate. Total shares purchased pursuant to the purchase program were 76,283 common shares at a cost of \$5 million (\$65.73 average price paid per share), including 68,943 shares from our executive officers at a cost of \$4.6 million (\$67.22 price paid per share). The authorization to purchase the remaining 1,400,826 shares effectively expired on April 30, 2008. All shares purchased in accordance with the program were subsequently retired.

Pursuant to our senior notes indenture entered in February 2008, any future treasury purchases are limited, see Note 8 – Long-Term Debt.

Shareholders' Rights Agreement

In 2007, we entered into a rights agreement. The rights agreement is designed to improve the ability of our Board to protect the interest of our shareholders in the event of an unsolicited takeover attempt. Our Board declared a dividend of one right for each outstanding share of our common stock. The right dividend was paid to shareholders of record on September 14, 2007. A "distribution date," as defined in the rights agreement, can occur after any individual shareholder exceeds 15% ownership of our outstanding common stock. After the occurrence of a "distribution date," the right entitles each registered holder (other than the acquiring shareholder who triggered the "distribution date"), to purchase shares of our common stock (or, in certain circumstances, cash, property or other securities) having a then-current value equal to two times the exercise price of the right (i.e., for the \$240 exercise price, the rights holder receives \$480 worth of common stock). The exercise price is subject to adjustment for various corporate actions which affect all shareholders, such as a stock split. The rights agreement and all rights will expire on September 11, 2017.

Common and Preferred stock

In July 2008, pursuant to shareholder approval, we amended and restated our Articles of Incorporation to: (1) increase the number of the Company's authorized shares of common stock, par value \$0.01, from 50,000,000 shares to 100,000,000 shares, and (2) authorize 50,000,000 shares of Company preferred stock, par value \$0.01, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by our Board from time to time. As of December 31, 2009, no preferred stock had been issued.

NOTE 13 – NONCONTROLLING INTEREST IN SUBSIDIARIES

WWWV, LLC

In May 2007, we contributed \$0.8 million for a 50% interest in WWWV, LLC (the "LLC"), a limited liability company for which we serve as the managing member. The LLC's only asset is an aircraft and the LLC was formed for the purpose of owning and operating the aircraft. We consolidate the entity based on a controlling financial interest.

PDC Mountaineer, LLC

On October 29, 2009, we entered into a joint venture arrangement with Lime Rock Partners to form PDC Mountaineer, LLC, a VIE. The joint venture was formed to develop our Marcellus Shale acreage and shallow Devonian assets in the Appalachian Basin. Under the terms of the agreement, we contributed acreage, producing properties and related reserves, gathering assets and equipment with an estimated fair value of \$158.5 million for which we received a return of capital cash payment of \$45 million and a 67.4% interest at closing, with an option to receive an additional cash withdrawal of \$11.5 million by the end of 2010. Lime Rock contributed \$55 million at closing and will fund up to an additional \$58.5 million as needed for drilling and operations until it earns a 50% interest in the joint venture. We anticipate the partner's funding obligation to be reached in 2011. After the 50% interest is earned, all future costs and capital investments will be shared equally.

The assets we contributed consist of (i) approximately 115,000 net acres in the Appalachian Basin, of which approximately 55,000 acres are in the Marcellus fairway, (ii) 12 MMcf per day of existing production from primarily the shallow Devonian sands, and (iii) total proved reserves of 113 Bcfe, also from the shallow Devonian sands. None of our affiliated partnerships' wells were included in the joint venture.

F-37

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The joint venture was determined to be a variable interest entity due to the disproportionate voting rights compared to the ownership rights. We consolidated the joint venture as a result of being the primary beneficiary. See Note 2, Summary of Significant Accounting Policies - Recent Accounting Standards, Recently Issued Accounting Standards, Consolidation – Variable Interest Entities.

With the exception of our capital contribution, we have not entered into any arrangement that would require us to provide financial support to the joint venture. Further, we are not liable for any debts, obligations and liabilities of the joint venture and its creditors have no recourse against our general credit in the event of default.

The following table presents the carrying amount and classification of the joint venture's assets and liabilities on our balance sheet.

	December 31, 2009 (in thousands)
Cash and cash equivalents	\$ 9,428
Property, plant and equipment, net	158,788
Other assets	6,003
Total assets	\$ 174,219
Other current liabilities	\$ 12,224
Asset retirement obligation	14,769
Other liabilities	2,068
Total liabilities	\$ 29,061

During the fourth quarter of 2009, we paid and recognized in the statement of operations as a component of general and administrative expenses \$7.9 million in fees and expenses related to this transaction.

NOTE 14 - BUSINESS SEGMENTS

In the third quarter of 2009, our chief operating decision maker, a team of executive officers, ("CODM") began utilizing financial data reorganized to better reflect the core businesses in which we operate and how they manage the Company's resources. As the business of our oil and gas well drilling operations was completed in June 2009 and reported as discontinued operation, discrete financial information for this segment no longer exists beginning in July 2009. Further, well operations and pipeline income, formerly a separate segment, was included as a component of the oil and gas sales segment as of October 2009. The combination of these two activities better reflects how information is reported to and reviewed by our CODM.

We separate our operating activities into two segments: natural gas and oil sales and natural gas marketing. All material inter-company accounts and transactions between segments have been eliminated.

Natural Gas and Oil Sales. Our natural gas and oil sales segment includes all of our natural gas and oil properties. The segment represents revenues and expenses from the production and sale of natural gas and oil. Segment revenue includes natural gas and oil sales, commodity price risk management, net and well operation and pipeline income. Segment income (loss) consists of segment revenue less natural gas and oil production and well operations cost, exploration expense and impairment of natural gas and oil properties, direct general and administrative expense and DD&A expense. Segment DD&A expense was \$127.4 million for 2009, \$102.1 million for 2008 and \$69.3 million for 2007.

Natural Gas Marketing. Our natural gas marketing segment purchases, aggregates and resells natural gas produced by us and others. Segment income (loss) primarily represents sales from natural gas marketing and direct interest income less costs of natural gas marketing and direct general and administrative expense.

Unallocated amounts. Unallocated income includes unallocated other revenue less corporate general administrative expense, corporate DD&A expense, interest income and interest expense.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following tables present our segment information, reclassified for discontinued operations.

Year Ended December 31,	2009	2008	2007
	(in thousands)		
Revenues:			
Natural gas and oil sales	\$ 180,064	\$ 461,189	\$ 187,285
Natural gas marketing	64,635	140,263	103,624
Unallocated	19	293	828
Total	\$ 244,718	\$ 601,745	\$ 291,737
Segment income (loss) before income taxes:			
Natural gas and oil sales	\$(36,256)	\$ 234,673	\$ 44,635
Natural gas marketing	2,091	1,329	3,822
Unallocated	(92,757)	(67,846)	(5,867)
Total	\$(126,922)	\$ 168,156	\$ 42,590
Expenditures for segment long-lived assets:			
Natural gas and oil sales	\$ 140,431	\$ 316,959	\$ 233,516
Unallocated	2,602	6,194	5,472
Total	\$ 143,033	\$ 323,153	\$ 238,988
As of December 31,			
Segment assets:			
Natural gas and oil sales (1)	\$ 1,152,160	\$ 1,297,739	\$ 893,296
Natural gas marketing	22,614	50,117	40,269
Unallocated (2)	75,553	54,848	116,914
Total	\$ 1,250,327	\$ 1,402,704	\$ 1,050,479

(1) December 31, 2007, includes \$4.9 million previously included in our oil and natural gas well drilling segment. See Note 16, Discontinued Operations.

(2) December 31, 2008 and 2007, includes \$0.4 million and \$0.1 million, respectively, previously included in our oil and natural gas well drilling segment. See Note 16, Discontinued Operations.

NOTE 15 - TRANSACTIONS WITH AFFILIATES

Amounts due from/to the affiliated partnership are primarily related to derivative positions, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services.

We enter into derivative instruments for our own production as well as for our 33 affiliated partnerships' production. We enter into these derivative instruments for us and, as the managing general partner, for the affiliated partnerships jointly by area of operation. Prior to September 30, 2008, as volumes produced changed, the allocation between us and the affiliated partnerships changed. As of September 30, 2008, we fixed the allocation of the

derivative positions between us and each affiliated partnership. Fixed quantities of each of the then existing positions were allocated to us and the affiliated partnerships based upon current estimated future production. For positions entered into subsequent to September 30, 2008, specific designations of the quantities between us and the affiliated partnerships are made at the time the positions are entered into based on estimated future production. As of December 31, 2009, we have recorded a payable to affiliates of \$13.4 million representing their designated portion of the fair value of our gross derivative assets and a due from affiliates of \$21 million representing their designated portion of the fair value of our gross derivative liabilities.

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Our natural gas marketing segment manages the marketing of natural gas for our affiliated partnerships in the Appalachian Basin. Our sales from natural gas marketing include \$5.5 million, \$12.4 million and \$9.3 million in 2009, 2008 and 2007, respectively, related to the marketing of natural gas on behalf of our affiliated partnerships. Included in our cost of natural gas marketing is \$5.4 million, \$12.1 million and \$9.1 million for 2009, 2008 and 2007, respectively, related to these sales.

Through June 2009, we provided natural gas and oil well drilling services to our affiliated partnerships. As part of these services, we sold to them at cost the natural gas and oil leases upon which the wells are drilled. For the years ended December 31, 2008 and 2007, we sold to our affiliated partnerships leases in the amounts of \$0.5 million and \$1.4 million, respectively. Further, we provide well operations and pipeline services to our affiliated partnerships. The majority of all of our revenue and expenses related to well operations and pipeline income are associated with services provided to our affiliated partnerships. See Note 16, Discontinued Operations, for the natural gas and oil well drilling revenue recognized in 2009, 2008 and 2007.

NOTE 16 – DISCONTINUED OPERATIONS

We offered our last sponsored drilling partnership in October 2007. In January 2008, we first announced that we had no plans to sponsor a new drilling partnership in 2008 and this decision was upheld again in 2009. As of June 30, 2009, all remaining contractual drilling and completion obligations were completed for all partnerships. The unused advance for future drilling contracts of \$1.7 million as of December 31, 2008, was fully utilized as of June 30, 2009, with \$0.2 million recognized in revenue and \$0.3 million refunded to the partnerships.

As all partnership well drilling and completion activities have been completed and we currently do not have any plans in the foreseeable future to sponsor a drilling partnership, we believe it was appropriate to treat our natural gas and oil well drilling activities as discontinued operation for all periods presented. Prior period financial statements have been restated to present the activities of our natural gas and oil well drilling operations as discontinued operations.

The following table presents statements of operations data related to discontinued operations.

Statements of Operations Data:	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Revenues:			
Natural gas and oil well drilling	\$ 193	\$ 7,615	\$ 13,498
Cost and expenses:			
Cost of natural gas and oil well drilling (1)	-	1,068	1,939
Income from discontinued operations before income taxes	193	6,547	11,559
Provision for income taxes	80	2,370	4,476
Income from discontinued operations, net of tax	\$ 113	\$ 4,177	\$ 7,083

(1) Costs reclassified from cost of natural gas and oil well drilling to natural gas and oil production and well operations costs for the years ended December 31, 2009, 2008 and 2007 were \$0.6 million, \$1.1 million and \$0.6 million, respectively.

F-40

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

NOTE 17 - SALE OF NATURAL GAS AND OIL PROPERTIES

In July 2006, we sold to an unaffiliated company a portion of our undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. The sale encompassed 100% of the working interest in approximately 8,700 acres, including approximately 6,400 acres of the Chevron leasehold and 2,300 acres of the Puckett Land Company leasehold. We retained approximately 475 undeveloped locations on 10 acre spacing on the Grand Valley Field leasehold in addition to all of our producing properties in the field. The proceeds from the sale were \$353.6 million, which was recognized as a gain on sale of leaseholds in our statements of operations, \$328 million recorded in 2006 and \$25.6 million recorded in 2007.

In conjunction with the purchase and sale agreement described above, we entered into a Like-Kind Exchange ("LKE") agreement, in accordance with Section 1031 of the Internal Revenue Code, with a "qualified intermediary." Proceeds in the amount of \$300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. We had until mid-January 2007 to close any acquisition of suitable like-kind property, allowing us to take advantage of the income tax deferral benefits of a LKE transaction. Any unused amounts at that time would become taxable at our 2006 effective tax rate. See Note 18, Acquisitions, for a discussion of the qualifying acquisitions.

In December 2007, we sold to the same unaffiliated party above a portion of our North Dakota properties for approximately \$34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and approximately 72,000 net undeveloped acres. The reduction in our production and proved reserves as a result of this transaction was immaterial. We recorded a gain on sale of leaseholds of \$7.7 million in the fourth quarter of 2007. Following the sale, we retain ownership in three producing wells in Dunn County, ten producing wells in Burke County and approximately 60,000 acres of undeveloped leasehold in Burke County.

NOTE 18 – ACQUISITIONS

Acquisition of Internal Revenue Code Section 1031 – LKE Properties. In January 2007, we completed the acquisition of suitable like-kind properties in accordance with the LKE agreement we entered into in connection with our sale of undeveloped leaseholds located in Grand Valley Field, Garfield County, Colorado in July 2006. We acquired, with cash, qualifying natural gas and oil properties totaling \$188.9 million, including costs of acquisition, as described below.

EXCO Properties. We purchased producing properties and undeveloped drilling locations and acreage in the Wattenberg Field of the DJ Basin, Colorado from EXCO Resources Inc., an unaffiliated party. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 natural gas and oil wells (approximating 25.5 Bcfe proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold interests. The wells and leases acquired are located in Weld, Adams, Larimer and Broomfield Counties, Colorado. We operate the assets and hold a majority working interest in the properties.

Company Sponsored Partnerships. We purchased the remaining working interests in 44 of our sponsored partnerships. The transaction resulted in an increase in our ownership in 718 gross (423 net) wells that we currently operate. The wells are located primarily in the Appalachian Basin and Michigan.

Other. We acquired from unaffiliated parties undeveloped leaseholds in Erath County, Texas for \$2.1 million, including costs of acquisition. Acreage in this area is prospective for development of natural gas and oil reserves in the Barnett Shale.

Other Acquisitions. In February 2007, we acquired, from an unaffiliated party, 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of \$12 million, which was allocated to natural gas and oil properties.

In October 2007, with an effective date of October 1, 2007, we purchased from unrelated parties, Castle Gas Company, et.al., a majority working interest in 762 natural gas wells located in southwestern Pennsylvania for approximately \$54 million. We estimated that the acquisition included approximately 47 Bcfe of reserves, or 31 Bcfe of proved reserves and 16 Bcfe of unproved reserves. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage.

F-41

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Allocation of Final Purchase Price. The following table presents, as of the respective date of acquisition, the final allocation of the purchase price based on estimates of fair value.

	EXCO	Partnerships (in thousands)	Castle
Current assets acquired	\$ 91	\$ -	\$ 185
Proved natural gas and oil properties	117,099	59,081	55,778
Unproved natural gas and oil properties	14,960	-	217
Other properties and equipment	-	-	2,115
Other noncurrent assets	-	-	783
Asset retirement obligation	(422)	(2,433)	(4,043)
Other liabilities assumed	(1,513)	-	(968)
Total acquisition cost	\$ 130,215	\$ 56,648	\$ 54,067

The assessment of fair value of proved natural gas and oil properties acquired was based primarily on projections of expected discounted future cash flows of acquired natural gas and oil reserves. To compensate for the inherent risk of estimating and valuing unproved properties, the discounted future net revenues of probable reserves were reduced by additional risk-weighting factors in that valuation.

Pro Forma Financial Information. The results of operations for the above acquisitions have been included in our consolidated financial statements from the dates of acquisition. The pro forma effect of the inclusion in our consolidated statement of operations for the year ended December 31, 2007, of the results of operations for the January and February 2007 acquisitions described above, individually and in the aggregate, was not material.

The following unaudited pro forma financial information presents a summary of our consolidated results of operations for the year ended December 31, 2007, assuming the Castle properties had been completed as of January 1, 2007, including adjustments to reflect the allocation of the purchase price to the acquired net assets.

	Year Ended December 31, 2007 (in thousands, except per share data)
Total revenues	\$ 310,351
Net income	\$ 34,571
Earnings per common share:	
Basic	\$ 2.34
Diluted	\$ 2.33

The pro forma results of operations are not necessarily indicative of what our results of operations would have been had the Castle properties been acquired at the beginning of the period indicated, nor does it purport to represent our results of operations for any future periods.

F-42

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

SUPPLEMENTAL INFORMATION – UNAUDITED

NATURAL GAS AND OIL OPERATIONS

Costs Incurred in Natural Gas and Oil Property Acquisition, Exploration and Development Activities

Costs incurred in natural gas and oil property acquisition, exploration and development are presented below.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Acquisition of properties:			
Proved properties	\$ 2,251	\$ 6,147	\$ 257,330
Unproved properties	5,867	6,890	13,701
Development costs	72,416	257,656	194,031
Exploration costs:			
Exploratory drilling	18,317	26,499	12,972
Geological and geophysical	1,788	2,121	6,299
Total costs incurred	\$ 100,639	\$ 299,313	\$ 484,333

- Property acquisition costs - represent costs incurred to purchase, lease or otherwise acquire a property.
- Development costs - represents costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, recompletions and to provide facilities to extract, treat, gather and store natural gas and oil. Of these costs incurred for the years ended December 31, 2009, 2008 and 2007, \$49.1 million, \$66.2 million and \$37.1 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end.
- Exploration costs - represents costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing natural gas and oil reserves.

Capitalized Natural Gas and Oil Costs

Aggregate capitalized costs related to natural gas and oil exploration and production activities with applicable accumulated DD&A are presented below:

	December 31,	
	2009	2008
	(in thousands)	
Proved natural gas and oil properties (1)	\$ 1,329,666	\$ 1,169,969
Unproved natural gas and oil properties	38,626	32,768
	1,368,292	1,202,737
Less accumulated DD&A	428,754	306,142
	\$ 939,538	\$ 896,595

-
- As of December 31, 2009, we had no capitalized proved undeveloped natural gas and oil properties disclosed as such for longer than 5 years.

F-43

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

Results of Operations for Natural Gas and Oil Producing Activities

The results of operations for natural gas and oil producing activities, excluding natural gas marketing, are presented below.

	Year Ended December 31,		
	2009	2008	2007
	(in thousands)		
Revenue:			
Natural gas and oil sales	\$ 179,093	\$ 321,877	\$ 175,187
Commodity price risk management gain, net	(10,053)	127,838	2,756
	169,040	449,715	177,943
Expenses:			
Production costs	57,825	72,518	44,238
DD&A	125,415	100,207	68,086
Exploration costs	22,887	45,105	23,551
	206,127	217,830	135,875
Results of operations for natural gas and oil producing activities before provision for income taxes			
	(37,087)	231,885	42,068
Provision (benefit) for income taxes	(13,833)	86,493	16,280
Results of operations for natural gas and oil producing activities, excluding corporate overhead and interest costs			
	\$ (23,254)	\$ 145,392	\$ 25,788

Production costs include those costs incurred to operate and maintain productive wells and related equipment, including costs such as labor, repairs, maintenance, materials, supplies, fuel consumed, insurance and production and severance taxes. In addition, production costs include administrative expenses and depreciation applicable to support equipment associated with these activities. DD&A expense includes those costs associated with capitalized acquisition, exploration and development costs, but does not include the depreciation applicable to support equipment. The provision for income taxes is computed using effective tax rates.

Net Proved Natural Gas and Oil Reserves

We utilized the services of independent petroleum engineers to estimate our natural gas and oil reserves. For each of the three years in the three-year period ended December 31, 2009, our reserve estimates for the Appalachian and Michigan Basins are based on reserve reports prepared by Wright & Company and for the Rocky Mountain Region and Fort Worth Basin, reserve estimates are based on reserve reports prepared by Ryder Scott Company, L.P. These reserve estimates have been prepared in compliance with professional standards and the reserves definitions prescribed by the SEC.

Proved reserves estimates may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. Our net proved reserve estimates have been adjusted as necessary to reflect all contractual agreements, royalty obligations and interests owned by others at the time of the

estimate. Proved developed reserves are the quantities of natural gas and oil expected to be recovered through existing wells with existing equipment and operating methods. In some cases, proved undeveloped reserves may require substantial new investments in additional wells and related facilities.

F-44

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

The prices used to estimate our reserves, by commodity, are presented below.

	Price	
	Oil	Gas
2009	\$ 54.64	\$ 3.17
2008	37.85	4.98
2007	80.67	6.77

Our estimated 2009 reserve values below were based on 12-month average prices. Using the prior SEC reporting guidelines for quantifying reserves as of December 31, 2009, the Company would have used a year-end spot price of \$5.51 per Mcf and \$72.91 per Bbl, for natural gas and oil, respectively. Under the prior methodology, total reserves would have been approximately 94 Bcfe higher, or 811 Bcfe, as of December 31, 2009.

The following tables present the changes in our estimated quantities of natural gas and oil reserves.

	Natural Gas (MMcf)	Oil (MBbl)	Total (MMcfe)
Proved Reserves:			
Proved reserves, January 1, 2007	279,078	7,272	322,710
Revisions of previous estimates	14,177	1,375	22,427
Extensions, discoveries and other additions			
Rocky Mountain Region	210,402	3,700	232,602
Appalachian Basin	5,493	-	5,493
Michigan Basin	488	-	488
Purchases of reserves			
Rocky Mountain Region	39,239	4,490	66,179
Appalachian Basin	63,014	2	63,026
Michigan Basin	6,059	-	6,059
Dispositions to partnerships	(1,874)	(591)	(5,420)
Production	(22,513)	(910)	(27,973)
Proved reserves, December 31, 2007	593,563	15,338	685,591
Revisions of previous estimates	(25,216)	(1,538)	(34,444)
Extensions, discoveries and other additions			
Rocky Mountain Region	100,323	2,354	114,447
Appalachian Basin	24,875	-	24,875
Purchases of reserves			
Rocky Mountain Region	1,712	106	2,348
Appalachian Basin	83	-	83
Michigan Basin	46	-	46
Dispositions to partnerships	(769)	(63)	(1,147)
Production	(31,760)	(1,160)	(38,720)
Proved reserves, December 31, 2008	662,857	15,037	753,079
Revisions of previous estimates	(101,923)	2,957	(84,181)

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Extensions, discoveries and other additions			
Rocky Mountain Region	79,574	1,322	87,506
Appalachian Basin	3,190	-	3,190
Purchases of reserves			
Rocky Mountain Region	648	47	930
Appalachian Basin	59	-	59
Other	63	-	63
Dispositions to partnerships	(7)	(1)	(13)
Production	(35,536)	(1,292)	(43,288)
Proved reserves, December 31, 2009	608,925	18,070	717,345

F-45

Table of Contents

	Natural		
	Gas	Oil	Total
	(MMcf)	(MBbl)	(MMcfe)
Proved Developed Reserves, as of:			
January 1, 2007	144,672	3,503	165,690
December 31, 2007	286,570	5,219	317,884
December 31, 2008	297,041	5,438	329,669
December 31, 2009	258,375	6,244	295,839
Proved Undeveloped Reserves, as of:			
January 1, 2007	134,406	3,769	157,020
December 31, 2007	306,993	10,119	367,707
December 31, 2008	365,816	9,599	423,410
December 31, 2009	350,550	11,826	421,506

PETROLEUM DEVELOPMENT CORPORATION

2009 Activity. In 2009, we revised our previous estimate of proved reserves downward by 84.2 Bcfe. The revision was primarily due to a decrease of 99.5 Bcfe due to lower commodity pricing and 45.1 Bcfe due to adjustments to reserves removed or reclassified due to new rules limiting proved undeveloped reserves location to those scheduled to be drilled within the next five years. The downward adjustments were partially offset by an increase of 41.4 Bcfe due to decreased operating costs, 1 Bcfe due to interest adjustments and 17.9 Bcfe due to asset performance. New discoveries and extensions of 90.7 Bcfe in 2009 are due to drilling of 100 gross wells and the addition of new proved undeveloped reserves: 3.2 Bcfe in the Appalachian Basin and 87.5 Bcfe in the Rocky Mountain Region (13.7 Bcfe in Wattenberg Field, 73.3 Bcfe in Grand Valley Field, and 0.5 Bcfe in North Dakota). We acquired 1.1 Bcfe of proved reserves through the purchase of interest in some of our existing properties. We acquired reserves primarily in the Wattenberg Field with the remaining reserves split between the Appalachian Basin, Michigan Basin, Piceance Basin and North Dakota. We sold a minimal amount of reserves to unaffiliated third parties in the Wattenberg Field.

2008 Activity. In 2008, we revised our previous estimate of proved reserves downward by 34.4 Bcfe. The revision was primarily due to a decrease of 50 Bcfe due to lower commodity prices, 25.8 Bcfe due to increased operating costs, and 14.4 Bcfe due to adjustments to proved undeveloped reserve values, partially offset by an increase of 55.8 Bcfe due to asset performance. New discoveries and extensions of 139.3 Bcfe in 2008 are due to drilling of 229 net wells and the addition of new proved undeveloped reserves: 24.9 Bcfe in the Appalachian Basin and 114.4 Bcfe in the Rocky Mountain Region (26.6 Bcfe in the Wattenberg Field, 80 Bcfe in Grand Valley Field, and 7.8 Bcfe in NECO and other areas). We acquired 2.5 Bcfe of proved reserves through the purchases of interest in some of our existing properties. We acquired reserves primarily in the Wattenberg Field with the remaining reserves being split between the Appalachian Basin, Michigan, Piceance, the NECO area and North Dakota. We sold proved reserves of 1.1 Bcfe to unaffiliated third parties and to our sponsored partnerships for drilling activity.

2007 Activity. In 2007, we revised our previous estimate of proved reserves upward by 22.4 Bcfe. The revision was primarily due to an increase of 25 Bcfe and 12 Bcfe, due to asset performance and higher commodity prices, respectively, partially offset by a decrease of 14.6 Bcfe due primarily to increased operating costs, adjustments to proved undeveloped reserve values and change in well ownership interests. New discoveries and extensions of 238.6 Bcfe in 2007 are due to the drilling of 218 net wells and the addition of 232.6 Bcfe of new proved undeveloped reserves in the Rocky Mountain Region (43.5 Bcfe in the Wattenberg Field, 170.4 Bcfe in Grand Valley Field and 18.7 Bcfe in the NECO area). We acquired 135.3 Bcfe of proved reserves through purchases of natural gas and oil properties: 65.5 Bcfe in the Wattenberg Field of the Rocky Mountain Region, 63 Bcfe in the Appalachian Basin and

6.1 Bcfe in the Michigan Basin. We sold proved reserves of 5.4 Bcfe to unaffiliated third parties and to our sponsored partnerships for drilling activity.

F-46

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Natural Gas and Oil Reserves

Presented in the following table is information with respect to the standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves.

	2009	2008	2007
	(in thousands)		
Future estimated cash flows	\$ 2,915,377	\$ 3,867,461	\$ 5,257,962
Future estimated production costs	(1,088,337)	(1,325,362)	(1,374,027)
Future estimated development costs	(825,139)	(1,100,533)	(876,961)
Future estimated income tax expense	(237,790)	(384,676)	(1,159,489)
Future net cash flows	764,111	1,056,890	1,847,485
10% annual discount for estimated timing of cash flows	(416,475)	(700,085)	(1,094,414)
Standardized measure of discounted future estimated net cash flows	\$ 347,636	\$ 356,805	\$ 753,071

Future cash inflows are computed by applying prices used in estimating the entity's proved natural gas and oil reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

The following table presents the principal sources of change in the standardized measure of discounted future estimated net cash flows.

	2009	2008	2007
	(in thousands)		
Sales of natural gas and oil production net of production costs	\$ (136,568)	\$ (261,692)	\$ (137,725)
Net changes in prices and production costs	(107,766)	(479,894)	157,797
Extensions, discoveries, and improved recovery, less related costs	30,851	80,859	317,031
Sales of reserves	(21)	(2,012)	(7,846)
Purchase of reserves	1,266	4,280	342,792
Development costs incurred during the period	40,603	88,008	42,510
Revisions of previous quantity estimates	(46,226)	(79,536)	92,462
Changes in estimated income taxes	38,371	239,054	(335,327)
Net changes in future development costs	101,765	(87,625)	-
Accretion of discount	49,434	122,409	38,660
Timing and other	19,122	(20,117)	27,055

Total	\$ (9,169)	\$ (396,266)	\$ 537,409
-------	-------------	---------------	------------

It is necessary to emphasize that the data presented should not be viewed as representing the expected cash flow from, or current value of, existing proved reserves since the computations are based on a large number of estimates and arbitrary assumptions. Reserve quantities cannot be measured with precision and their estimation requires many judgmental determinations and frequent revisions. The required projection of production and related expenditures over time requires further estimates with respect to pipeline availability, rates of demand and governmental control. Actual future prices and costs are likely to be substantially different from the current prices and costs utilized in the computation of reported amounts. Any analysis or evaluation of the reported amounts should give specific recognition to the computational methods utilized and the limitations inherent therein.

F-47

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

QUARTERLY FINANCIAL DATA

Quarterly financial data for the years ended December 31, 2009 and 2008, is presented below. The sum of the quarters may not equal the total of the year's net income per share due to changes in the weighted average shares outstanding throughout the year.

	2009				
	March 31,	June 30,	September 30,	December 31,	Year Ended
	(in thousands, except per share data)				
Revenues:					
Natural gas and oil sales	\$39,742	\$41,558	\$ 44,006	\$ 53,787	\$179,093
Sales from natural gas marketing	22,389	12,367	12,444	17,435	64,635
Commodity price risk management gain (loss), net	23,683	(23,284)	(13,813)	3,361	(10,053)
Well operations, pipeline income and other	2,838	2,948	2,563	2,694	11,043
Total revenues	88,652	33,589	45,200	77,277	244,718
Costs and expenses:					
Natural gas and oil production and well operations costs	16,361	14,044	15,218	19,123	64,746
Cost of natural gas marketing	21,878	11,992	11,556	17,108	62,534
Exploration expense and impairment of natural gas and oil properties	5,643	3,133	6,586	7,525	22,887
General and administrative expense	12,094	14,784	9,627	17,480	53,985
Depreciation, depletion and amortization	34,360	33,860	32,576	30,208	131,004
Total costs and expenses	90,336	77,813	75,563	91,444	335,156
Gain on sale of leaseholds	120	-	-	350	470
Loss from operations	(1,564)	(44,224)	(30,363)	(13,817)	(89,968)
Interest income	20	12	208	14	254
Interest expense	(8,383)	(9,420)	(9,221)	(10,184)	(37,208)
Loss from continuing operations before income taxes	(9,927)	(53,632)	(39,376)	(23,987)	(126,922)
Benefit for income taxes	(4,095)	(20,537)	(14,601)	(6,483)	(45,716)
Loss from continuing operations	(5,832)	(33,095)	(24,775)	(17,504)	(81,206)
Income from discontinued operations, net of tax	113	-	-	-	113
Net loss	(5,719)	(33,095)	(24,775)	(17,504)	(81,093)
Less: net loss attributable to noncontrolling interests	(16)	(16)	(299)	(1,485)	(1,816)
Net loss attributable to shareholders	\$(5,703)	\$(33,079)	\$(24,476)	\$(16,019)	\$(79,277)

Edgar Filing: PETROLEUM DEVELOPMENT CORP - Form 10-K

Amounts attributable to Petroleum

Development Corporation shareholders:

Loss from continuing operations	\$ (5,816)	\$ (33,079)	\$ (24,476)	\$ (16,019)	\$ (79,390)
Income from discontinued operations, net of tax	113	-	-	-	113
Net loss attributable to shareholders	\$ (5,703)	\$ (33,079)	\$ (24,476)	\$ (16,019)	\$ (79,277)

Earnings (loss) per share attributable shareholders:

Basic

Loss from continuing operations	\$ (0.39)	\$ (2.23)	\$ (1.44)	\$ (0.84)	\$ (4.83)
Income from discontinued operations	0.01	-	-	-	0.01
Net loss attributable to shareholders	\$ (0.38)	\$ (2.23)	\$ (1.44)	\$ (0.84)	\$ (4.82)

Diluted

Loss from continuing operations	\$ (0.39)	\$ (2.23)	\$ (1.44)	\$ (0.84)	\$ (4.83)
Income from discontinued operations	0.01	-	-	-	0.01
Net loss attributable to shareholders	\$ (0.38)	\$ (2.23)	\$ (1.44)	\$ (0.84)	\$ (4.82)

Weighted average common shares outstanding

Basic	14,793	14,811	16,962	19,172	16,448
Diluted	14,793	14,811	16,962	19,172	16,448

F-48

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

	2008				
	March 31,	June 30,	September 30,	December 31,	Year Ended
	Quarter Ended				
	(in thousands, except per share data)				
Revenues:					
Natural gas and oil sales	\$71,646	\$94,549	\$ 99,422	\$ 56,260	\$321,877
Sales from natural gas marketing	23,325	30,941	53,372	32,625	140,263
Commodity price risk management gain (loss), net	(42,310)	(101,798)	169,402	102,544	127,838
Well operations, pipeline income and other	2,355	2,472	3,376	3,564	11,767
Total revenues	55,016	26,164	325,572	194,993	601,745
Costs and expenses:					
Natural gas and oil production and well operations costs	18,203	21,330	22,582	17,239	79,354
Cost of natural gas marketing	22,121	30,117	54,372	32,624	139,234
Exploration expense and impairment of natural gas and oil properties	4,283	3,467	10,212	27,143	45,105
General and administrative expense	9,823	9,231	8,106	10,555	37,715
Depreciation, depletion and amortization	21,147	22,121	28,661	32,711	104,640
Total costs and expenses	75,577	86,266	123,933	120,272	406,048
Income (loss) from operations	(20,561)	(60,102)	201,639	74,721	195,697
Interest income	271	75	151	94	591
Interest expense	(4,932)	(6,394)	(7,817)	(8,989)	(28,132)
Income (loss) from continuing operations before income taxes	(25,222)	(66,421)	193,973	65,826	168,156
Provision (benefit) for income taxes	(9,343)	(23,844)	67,834	24,442	59,089
Income (loss) from continuing operations	(15,879)	(42,577)	126,139	41,384	109,067
Income (loss) from discontinued operations, net of tax	1,935	1,849	741	(348)	4,177
Net income (loss)	(13,944)	(40,728)	126,880	41,036	113,244
Less: net loss attributable to noncontrolling interests	(16)	(16)	(16)	(17)	(65)
Net income (loss) attributable to shareholders	\$(13,928)	\$(40,712)	\$ 126,896	\$ 41,053	\$113,309
Amounts attributable to Petroleum Development Corporation shareholders:					
Income (loss) from continuing operations	\$(15,863)	\$(42,561)	\$ 126,155	\$ 41,401	\$109,132
Income (loss) from discontinued operations, net of tax	1,935	1,849	741	(348)	4,177
Net income (loss) attributable to shareholders	\$(13,928)	\$(40,712)	\$ 126,896	\$ 41,053	\$113,309

Earnings (loss) per share attributable to shareholders:

Basic

Income (loss) from continuing operations	\$(1.08)	\$(2.89)	\$ 8.54	\$ 2.80	\$7.41
Income (loss) from discontinued operations	0.13	0.13	0.05	(0.02)	0.28
Net income (loss) attributable to shareholders	\$(0.95)	\$(2.76)	\$ 8.59	\$ 2.78	\$7.69

Diluted

Income (loss) from continuing operations	\$(1.08)	\$(2.89)	\$ 8.50	\$ 2.80	\$7.35
Income (loss) from discontinued operations	0.13	0.13	0.05	(0.02)	0.28
Net income (loss) attributable to shareholders	\$(0.95)	\$(2.76)	\$ 8.55	\$ 2.78	\$7.63

Weighted average common shares outstanding

Basic	14,738	14,742	14,767	14,778	14,736
Diluted	14,738	14,742	14,835	14,791	14,848

F-49

Table of Contents

PETROLEUM DEVELOPMENT CORPORATION

FINANCIAL STATEMENT SCHEDULE

Schedule II - VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1	Charged to Costs and Expenses	Deductions (a)	Ending Balance December 31
		(in thousands)		
2009:				
Allowance for doubtful accounts	\$ 537	\$ 120	\$ 109	\$ 548
Valuation allowance for state tax benefits	\$-	\$ 747	\$-	\$ 747
Valuation allowance for unproved natural gas and oil properties	\$ 12,870	\$ 7,279	\$ 5,148	\$ 15,001
2008:				
Allowance for doubtful accounts	\$ 357	\$ 180	\$-	\$ 537
Valuation allowance for unproved natural gas and oil properties	\$ 2,365	\$ 12,798	\$ 2,293	\$ 12,870
2007:				
Allowance for doubtful accounts	\$ 415	\$ 50	\$ 108	\$ 357
Valuation allowance for unproved natural gas and oil properties	\$ 596	\$ 2,183	\$ 414	\$ 2,365

(a)For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For calculation of allowance for unproved properties, deductions represent amortization of expired or abandoned unproved natural gas and oil properties.