

PETROLEUM DEVELOPMENT CORP
Form 8-K
January 14, 2008

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

FORM 8-K

CURRENT REPORT

Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): January 14, 2008

PETROLEUM DEVELOPMENT CORPORATION

(Exact name of registrant as specified in its charter)

Nevada (State or other jurisdiction of incorporation or organization)	0-7246 (Commission File Number)	95-2636730 (I.R.S. Employer Identification No.)
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120 Genesis Boulevard
Bridgeport, West Virginia
(Address of principal executive offices)
26330
(Zip Code)
Registrant's telephone number, including area code: 304-842-3597

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

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- .. Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

 - .. Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

 - .. Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.14d-2(b))

 - .. Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))
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Item 8.01. Other Events.

Petroleum Development Corporation is filing this Current Report on Form 8-K to provide updates of certain financial and other information, as set forth below in this Item 8.01, which reflects recent changes and developments. Unless otherwise indicated or the context requires otherwise, references in this report to PDC, we, us, our or ours refer, collectively, to Petroleum Development Corporation, its subsidiaries and its drilling partnerships, to the extent that such drilling partnerships are proportionately consolidated. Estimates of our proved natural gas and oil reserves at December 31, 2006 included in this report are based on reports prepared by Ryder Scott Company, LP and Wright & Company, our independent natural gas and petroleum consultants. Reserve estimates after December 31, 2006 are based on our internal estimates, and not on estimates of any independent petroleum engineering firm. Please see the Glossary of Terms beginning on page 31 for the definitions of certain natural gas and oil industry terms used in this report.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, which we refer to as the Securities Act, regarding our business, financial condition, results of operations and prospects. 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 oil and gas production and reserves, drilling plans, future cash flows, 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 petroleum natural resources;

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 of capital to us;

risks incident to the drilling and operation of natural gas and oil wells;

future production and development costs;

the effect of existing and future laws, governmental regulations and the political and economic climate of the United States;

the effect of natural gas and oil derivatives activities; and

conditions in the capital markets.

Further information about the risks and uncertainties that may affect us are described in the sections entitled "Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2006, which we refer to as our 2006 Form 10-K, and our subsequent Quarterly Reports on Form 10-Q. You should not place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update publicly 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.

NON-GAAP FINANCIAL MEASURES

The SEC has adopted rules to regulate the use of non-GAAP financial measures such as EBITDA, that are derived on the basis of methodologies other than in accordance with generally accepted accounting principles, or GAAP. EBITDA is a non-GAAP financial measure that complies with the Securities Act regulations when it is defined as net income (the most directly comparable GAAP financial measure) before interest, taxes, depreciation and amortization. We define EBITDA in this report accordingly.

EBITDA has limitations as an analytical tool, and you should not consider it in isolation, or as a substitute for analysis of our results as reported under GAAP. For example, EBITDA:

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(1) does not reflect our cash expenditures, or future requirements for capital expenditures or contractual commitments;

(2) does not reflect changes in, or cash requirements for, our working capital needs; and

(3) does not reflect the significant interest expense, or the cash requirements necessary to service interest or principal payments, on our debts.

In addition, although depreciation and amortization are non-cash charges, the assets being depreciated and amortized will often have to be replaced in the future, and EBITDA does not reflect any cash requirements for such replacements. Other companies in our industry and in other industries may calculate EBITDA differently from the way that we do, limiting its usefulness as a comparative measure. Because of these limitations, EBITDA should not be considered as a measure of discretionary cash available to us to invest in the growth of our business. We compensate for these limitations by relying primarily on our GAAP results and using EBITDA only supplementally.

INDUSTRY AND MARKET DATA

We have obtained some industry and market share data from third-party sources that we believe are reliable. In many cases, however, we have made statements in this report regarding our industry and our position in the industry based on estimates made from our experience in the industry and our own investigation of market conditions. We believe these estimates to be accurate as of the date of this report. However, this information may prove to be inaccurate because of the method by which we obtained some of the data for our estimates or because this information cannot always be verified with complete certainty due to the limits on the availability and reliability of raw data, the voluntary nature of the data gathering process and other limitations and uncertainties. As a result, you should be aware that the industry and market data included in this report, and estimates and beliefs based on that data, may not be reliable. We cannot guarantee the accuracy or completeness of any such information.

SUMMARY CONSOLIDATED HISTORICAL FINANCIAL INFORMATION

The following table shows summary consolidated historical financial information as of and for the years ended December 31, 2004, 2005, and 2006, as of and for the nine months ended September 30, 2006 and 2007 and for the twelve months ended September 30, 2007. The financial information for each of the three years ended December 31, 2006 was derived from our audited financial statements. The financial information as of September 30, 2007 and for the nine months ended September 30, 2007 and 2006 and the twelve months ended September 30, 2007 was derived from our unaudited consolidated financial statements. The unaudited consolidated financial information for the twelve months ended September 30, 2007 was derived by: (1) adding our consolidated historical financial information for the year ended December 31, 2006 to (2) our consolidated historical financial information for the nine months ended September 30, 2007 and subtracting (3) our consolidated historical financial information for the nine months ended September 30, 2006. In the opinion of management, the unaudited consolidated financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the financial condition and results of operations for these periods. Operating results for the nine months ended September 30, 2007 and 2006 and the twelve months ended September 30, 2007 are not necessarily indicative of the results that may be expected for any full fiscal year. Our historical results are not necessarily indicative of results to be expected in future periods. The summary consolidated historical financial information below should be read together with, and is qualified in its entirety by reference to, our consolidated historical financial statements and the accompanying notes and Management's Discussion and Analysis of Financial Condition and Results of Operations, included in our 2006 Form 10-K and our subsequent Quarterly Reports on Form 10-Q.

	Year Ended December 31,			Nine Months Ended September 30,		Twelve Months Ended September 30,
	2004	2005	2006	2006 (unaudited)	2007 (unaudited)	2007 (unaudited)
	(in thousands, except ratios)					
Income Statement Information:						
Revenues	\$ 264,483	\$ 325,198	\$ 286,503	\$ 218,330	\$ 210,132	\$ 278,305
Costs and expenses	210,952	267,420	232,701	175,886	192,444	249,259
Gain on sale of leaseholds		7,669	328,000	328,000	25,600	25,600
Income from operations	53,531	65,447	381,802	370,444	43,288	54,646
Interest income	185	898	8,050	4,216	2,059	5,893
Interest expense	(238)	(217)	(2,443)	(1,154)	(4,825)	(6,114)
Income before income taxes	53,478	66,128	387,409	373,506	40,522	54,425
Income taxes	20,250	24,676	149,637	143,697	15,511	21,451
Net income	\$ 33,228	\$ 41,452	\$ 237,772	\$ 229,809	\$ 25,011	\$ 32,974
Other Financial Information:						
EBITDA ⁽¹⁾	\$ 71,687	\$ 86,563	\$ 415,537	\$ 392,936	\$ 94,145	\$ 116,746
Net cash provided by (used in) operating activities	\$ 73,301	\$ 112,372	\$ 67,390	\$ (11,311)	\$ (32,800)	\$ 45,901
Net cash provided by (used in) investing activities	\$ (43,346)	\$ (94,042)	\$ (9,626)	\$ (78,811)	\$ (168,459)	\$ (99,274)
Net cash provided by (used in) financing activities	\$ (31,398)	\$ (5,290)	\$ 46,452	\$ 8,232	\$ 35,545	\$ 73,765
Ratio of earnings to fixed charges ⁽²⁾	159.2x	209.6x	93.2x	158.9x	6.2x	6.6x

	Nine Months				
	Ended				
	Year Ended December 31,			September 30,	
	2004	2005	2006	2006	2007
	(in thousands)				
Balance Sheet Information (end of period):					
Cash and cash equivalents	\$ 77,070	\$ 90,110	\$ 194,326	\$ 8,220	\$ 28,612
Total assets	\$ 329,453	\$ 444,361	\$ 884,287	\$ 773,422	\$ 933,751
Total current liabilities	\$ 119,531	\$ 180,740	\$ 241,834	\$ 140,202	\$ 199,086
Total debt	\$ 21,000	\$ 24,000	\$ 117,000	\$ 85,000	\$ 172,000
Total liabilities	\$ 175,432	\$ 256,096	\$ 524,143	\$ 406,403	\$ 546,136
Stockholders' equity	\$ 154,021	\$ 188,265	\$ 360,144	\$ 367,019	\$ 386,839

- (1) EBITDA is a non-GAAP financial measure that we define as net income before interest, taxes, depletion, depreciation and amortization. EBITDA, as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. EBITDA should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by or used in operating, investing and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. However, our management believes EBITDA is useful to an investor in evaluating our operating performance because this measure:

is widely used by investors in the energy industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;

helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure and asset base from our operating structure; and

is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting, and as a component for setting incentive compensation. There are significant limitations to using EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, and the lack of comparability of results of operations of different companies. The following table reconciles our net income, the most directly comparable GAAP financial measure, to EBITDA:

	Nine Months					Twelve Months Ended September 30, 2007 (unaudited)
	Ended					
	Year Ended December 31,			September 30,		
	2004	2005	2006	2006	2007	
	(in thousands)					
Net income	\$ 33,228	\$ 41,452	\$ 237,772	\$ 229,809	\$ 25,011	\$ 32,974
Interest expense, net	53	(681)	(5,607)	(3,062)	2,766	221
Income taxes	20,250	24,676	149,637	143,697	15,511	21,451
Depreciation, depletion and amortization	18,156	21,116	33,735	22,492	50,857	62,100
EBITDA ^(a)	\$ 71,687	\$ 86,563	\$ 415,537	\$ 392,936	\$ 94,145	\$ 116,746

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- (a) In July 2006, we recorded a one-time partial gain of \$328.0 million related to the sale of undeveloped acreage to Marathon Oil Company, with the remaining gain of \$25.6 million recorded in the second quarter of 2007. Absent this sale, EBITDA

for the nine months ended September 30, 2007 would have been \$68,545, and EBITDA for the twelve months ended September 30, 2007 would have been \$91,146.

- (2) For purposes of determining the ratio of earnings to fixed charges, earnings are defined as net income before income taxes, extraordinary items, amortization of capitalized interest and fixed charges, less capitalized interest. Fixed charges consist of interest (whether expensed or capitalized), amortization of debt expenses and discount or premium relating to any indebtedness and dividends on preferred stock.

BUSINESS

Our Company

We are an independent energy company engaged primarily in the development, production and marketing of natural gas and oil. Since we began our 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 activities. Our internal estimate of our total proved reserves, as of June 30, 2007, is 607 billion cubic feet of natural gas equivalent, or Bcfe. Since that time, we acquired approximately 47.0 Bcfe of additional internally estimated proved reserves located in the Appalachian Basin, which brings our internal estimate of proved reserves to 654 Bcfe at June 30, 2007 on a pro forma basis. As of December 31, 2006, we had interests in approximately 3,100 wells located in the Rocky Mountain region, the Appalachian Basin and the Michigan Basin, with proved reserves totaling 323 Bcfe. The substantial increase in our proved reserves since December 31, 2006 has been driven by our acquisition of an internally estimated total 195.1 Bcfe of proved reserves since January 1, 2007 and our successful drilling program this year. Our net production for the third quarter of 2007 averaged 83,919 thousand cubic feet of natural gas equivalent, per day, or Mcfe/d, which represents a 78.9% increase over our net production of 46,900 Mcfe/d in the third quarter of 2006.

Summary Pro Forma Reserve Data Internally Estimated as of June 30, 2007(1)

Area	Proved Developed Reserves (Bcfe)	Proved Undeveloped Reserves (Bcfe)	Total Proved Reserves (Bcfe)	% Developed	% Natural Gas
Appalachian Basin	81	31	112	72.4%	99.8%
Michigan Basin	25	25	25	100.0%	98.9%
Rocky Mountain Region	240	277	517	46.5%	84.9%
Total	346	308	654	52.9%	88.0%

(1) Includes an internally estimated 47.0 Bcfe of proved reserves acquired from Castle Gas Company, Inc. on October 30, 2007.

Business Segments

We divide our operating activities into four segments:

Oil and gas sales;

Drilling and development;

Natural gas marketing; and

Well operations and pipeline income.

Oil and Gas Sales

Our oil and gas sales segment reflects revenues and expenses from the production and sale of natural gas and oil. Revenues from natural gas and oil sales for the year ended December 31, 2006 were \$115.2 million. For the nine months ended September 30, 2007, these revenues were \$117.7 million compared to \$86.9 million for the first nine months of 2006, reflecting an increase due primarily to increased volumes of natural gas and oil partially offset by lower average sales prices. Total production for 2006 was 16.9 Bcfe, and total production for the first nine months of 2007 was 19.5 Bcfe. This segment represented approximately 70.9% of our income before income taxes for the nine months ended September 30, 2007.

Drilling and Development

Our drilling and development segment reflects our revenues and expenses associated with our well development and drilling activities. Historically, we have engaged in these activities primarily through sponsoring drilling partnerships, which allowed us to share the risks and costs inherent in drilling and development operations with our investor partners. In the future, we plan to evaluate the conduct of our drilling and development operations based on a comparison of the capital costs and risks associated with available financing alternatives. Beginning with our third drilling partnership in 2005, we have drilled partnership wells on a cost-plus basis, which means that we bill our investor partners for the actual drilling costs plus an agreed upon margin. In addition, we have typically purchased a 20% to 37% working interest in the wells developed through these partnerships. In 2006, we raised approximately \$90 million through investor subscriptions in one drilling partnership, and in August 2007 we raised approximately \$90 million through an additional drilling partnership. Our drilling and development segment represented approximately 14.2% of our income before income taxes for the nine months ended September 30, 2007. On January 7, 2008, we announced that we do not plan to sponsor new drilling partnerships in 2008 in order to focus our efforts on maximizing the value of the existing partnerships and continuing growth of our company through drilling and exploration.

Natural Gas Marketing

Our natural gas marketing segment is composed of our wholly owned subsidiary, Riley Natural Gas Company, or RNG, through which we purchase, aggregate and resell natural gas produced by us and others. Through RNG, we have established relationships with many of the leading natural gas producers in the Appalachian Basin and we have gained significant expertise in the natural gas end-user market. RNG also manages the marketing of natural gas and oil for our wells outside the Appalachian Basin, but does not market natural gas or oil for non-affiliated producers in those areas. We do not take speculative positions on commodity prices, and we employ hedging strategies to manage the financial effects of commodity price volatility. Our natural gas marketing segment represented approximately 5.8% of our income before income taxes for the nine months ended September 30, 2007.

Well Operations and Pipeline Income

We operate approximately 95% of the wells in which we own an interest. With respect to wells in which we own a working interest of less than 100%, we charge the other working interest owners a market-based fee for operating the well. Our well operations segment reflects these revenues and the associated costs. Our well operations and pipeline income segment represented approximately 4.7% of our income before income taxes for the nine months ended September 30, 2007.

Areas of Operations

We divide our operations into four geographic regions:

Rocky Mountain region, where we began operations in 1999, which includes our Colorado and North Dakota operations;

Appalachian Basin, where we have conducted operations since our inception in 1969;

Michigan Basin, where we began operations in 1997; and

Fort Worth Basin in North Texas, where we drilled our first exploratory well in the Barnett Shale formation in the fourth quarter of 2007.

During the nine months ended September 30, 2007, we generated approximately 83.6% of our production from Rocky Mountain region wells, 9.8% of our production from Appalachian Basin wells and 6.6% of our production from Michigan Basin wells. The majority of our undeveloped acreage is in the Rocky Mountain region and our current drilling plans continue to be focused in that area.

Historically, we have targeted developmental natural gas reserves at depths of less than 10,000 feet. Recently we began to drill to progressively deeper targets in the Rocky Mountain region. In particular, we have drilled several wells with depths of more than

12,000 feet and horizontal wells with total drilled footages approaching 20,000 feet. We believe these deeper and longer horizontal wells, although more expensive to drill, offer attractive economics and reserve potential. However, the probability of encountering problems when drilling wells at depths greater than 12,000 feet or horizontally is generally greater than when drilling a vertical well of lesser depth. Nevertheless, with increasing costs for, and declining availability of, proved developed drilling locations, we believe the additional risk associated with limited exploratory drilling is justified by the potential to generate additional proved locations at a significantly lower cost than would be required to purchase proved undeveloped locations.

Business Strategy

Our primary objective is to continue to grow our reserves, production, net income and cash flow. To achieve meaningful increases in these key categories, we maintain an active drilling program that focuses on low risk development of our natural gas and oil reserves, limited exploratory drilling and the acquisition of producing properties with significant development potential.

Drill and Develop

Our acreage holdings include positions in the Rocky Mountain region, which includes the Denver-Julesburg, Piceance and Williston Basins, as well as acreage in the Appalachian, Michigan and Fort Worth Basins. In the Rocky Mountain region, we focus on developmental drilling in Northeastern Colorado, or NECO, in the Wattenberg Field, and in the Piceance Basin. During the nine months ended September 30, 2007, we drilled 264 gross wells, compared to 231 wells during the twelve months ended December 31, 2006. In addition, we seek to maximize the value of our existing wells through a program of well recompletions. During the first nine months of 2007, we have recompleted 100 wells in the Colorado Wattenberg Field. We believe that we will be able to continue to drill a substantial number of new wells on our current undeveloped properties. At September 30, 2007, we had leases or other development rights to 210,675 undeveloped acres in the Rocky Mountain region, 16,575 undeveloped acres in the northern Appalachian Basin, 120 undeveloped acres in the Michigan Basin and 8,850 undeveloped acres in the Fort Worth Basin. Also, in order to support our future development activities, we plan to continue our exploratory drilling efforts for the remainder of 2008, with the goal of developing several significant new areas for our future development drilling activity.

Leverage Our Expertise Across Geographic Regions

With operations in the Rocky Mountain region and in the Appalachian and Michigan Basins, we have proven our ability to grow in geographically diverse areas. Within each area, we have concentrated positions that lend themselves to effective development and we operate over 95% of our wells. We plan to conduct the majority of our drilling activities in the Rocky Mountain region during 2008, and we will continue to seek additional opportunities for expansion in other geographic areas where we believe we can successfully apply our experience and expertise.

Strategically Acquire

Our acquisition efforts are primarily focused on producing properties that complement our existing operations. However, we will periodically evaluate potential acquisitions in areas where we are establishing new operations including the Barnett Shale in the Fort Worth Basin and in the Williston Basin. When weighing potential acquisitions, we prefer those properties that have most of their value in producing wells, behind pipe reserves or high quality proved undeveloped locations. Historically, acquisitions have offered efficiency improvements through economies of scale in management and administration costs. In the past twelve months we have completed three acquisitions of assets or companies in our core operating area of the Wattenberg Field in Colorado, and on October 30, 2007, we completed an acquisition of assets in southwestern Pennsylvania which are in close proximity to our existing assets in the Appalachian Basin.

Manage Risk

We seek opportunities to reduce the risks inherent to our business in the natural gas and oil industry by focusing our drilling efforts primarily on lower risk development wells and by maintaining positions in several different geographic regions and markets. 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 due to our success in that area over the past several years. However, we do enjoy operational diversity in the Rocky Mountain region by maintaining significant activity and production from three separate areas, including the Piceance Basin in western Colorado, the Wattenberg Field in northern Colorado and the NECO area. 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. However, we expect that future activities will include a somewhat higher level of exploratory drilling in light of the increasing cost of accessing high-quality development opportunities and our ability, through increased size and financial strength, to pursue exploratory activities of greater significance. Additionally, exploratory wells have the potential to identify new development opportunities at a significantly lower cost than the current cost of acquiring proven locations.

To help manage the risks associated with the natural gas and oil industry, we maintain a conservative financial approach and proactively employ strategies to reduce commodity price volatility. We have utilized asset sales to reduce debt and preserve our financial flexibility and have also accessed outside capital through our drilling partnerships to diversify funding sources. We also believe that successful natural gas and oil marketing is essential to risk management and profitable operations. To further this goal, we utilize RNG to manage the marketing of our natural gas and oil and our use of natural gas and oil commodity derivatives as risk management tools. This allows us to maintain better control over third-party risk in sales and derivative activities. We also use natural gas and oil derivatives as part of a hedging program aimed at reducing the effects of volatile commodity prices. We currently have hedges on a significant portion of our production.

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As of January 4, 2008, our hedge positions were as follows:

Month Set	Month		Monthly Quantity Bbls	Swap Price				
Oil NYMEX Based (Wattenberg Field)								
Oct-07	Jan 2008	Dec 2008	29,000	\$ 84.20				
Month Set	Month		Floors Monthly Quantity Mmbtu	Contract Price	Ceilings Monthly Quantity Mmbtu	Contract Price	Swaps (Fixed Prices) Monthly Volume Mmbtu	Price
Colorado Interstate Gas (CIG) Based Hedges (Piceance Basin)								
Dec-06	Nov 2007	Mar 2008	100,000	\$ 5.25				
Jan-07	Nov 2007	Mar 2008	100,000	\$ 5.25	100,000	\$ 9.80		
May-07	Apr 2008	Oct 2008	197,250	\$ 5.50	197,250	\$ 10.35		
Jan-08	Apr 2008	Oct 2008					294,000	\$ 6.54
NYMEX Based Hedges (Appalachian and Michigan Basins)								
Dec-06	Nov 2007	Mar 2008	144,500	\$ 7.00				
Jan-07	Nov 2007	Mar 2008	144,500	\$ 7.00	144,500	\$ 13.70		
Jan-07	Apr 2008	Oct 2008	144,500	\$ 6.50	144,500	\$ 10.80		
May-07	Apr 2008	Oct 2008	120,000	\$ 7.00	120,000	\$ 13.00		
Panhandle Based Hedges (NECO)								
Dec-06	Nov 2007	Mar 2008	70,000	\$ 5.75				
Jan-07	Nov 2007	Mar 2008	90,000	\$ 6.00	90,000	\$ 11.25		
Jan-07	Apr 2008	Oct 2008	90,000	\$ 5.50	90,000	\$ 9.85		
Jun-07	Apr 2008	Oct 2008	90,000	\$ 6.00	90,000	\$ 11.25		
Jan-08	Apr 2008	Oct 2008					120,000	\$ 6.80
Colorado Interstate Gas (CIG) Based Hedges (Wattenberg Field)								
Jan-07	Nov 2007	Mar 2008	120,000	\$ 5.25	120,000	\$ 9.80		
May-07	Apr 2008	Oct 2008	306,000	\$ 5.50	306,000	\$ 10.35		
Jan-08	Apr 2008	Oct 2008					200,000	\$ 6.54

Competitive Strengths

Expanding Base of High-Quality Reserves

We have a proven track record of successfully exploiting long-lived, geographically diverse basins to grow our proven reserves and production. Our proved reserves have grown from 99.3 Bcfe as of December 31, 2001 to an internally estimated 654 Bcfe currently, representing a 41% compound annual growth rate. As of September 30, 2007, the overall estimated reserve life of our internally estimated total proved reserves exceeded 21 years, based on our third quarter 2007 production, and these reserves were located in the Rocky Mountain region (including the Grand Valley Field in the Piceance Basin, the NECO and Wattenberg Fields of the Denver-Julesburg Basin, and the Western Williston Basin), the Appalachian Basin and the Michigan Basin (Antrim shale formation). Wells drilled in the Piceance, NECO and Wattenberg areas generally experience substantial production declines initially, but production stabilizes after several months and the wells produce for many years thereafter. Tight formations in the Appalachian Basin typically cause the wells to have productive lives of several decades with shallow, and relatively predictable, production decline rates. The majority of the wells in the Antrim shale formation are natural gas producers and tend to have flat production curves with long productive lives.

Stable Cash Flow

We believe that our long-lived, low production decline reserve base combined with our conservative leverage and active risk management profile should provide us with relatively stable and recurring cash flows. Over the last three years, cash flow from operations has ranged from 24% of revenues to 35% of revenues. This level of cash flow generation has enabled us a significant amount of flexibility to invest in development and exploratory drilling and to pursue acquisitions and debt retirement. Historically, we have primarily invested our cash flow in low risk development drilling and acquisitions aimed at increasing our production. However, these amounts have largely been discretionary and

exceed the spending rates required for us to maintain existing levels of production.

Focus on Low-Risk Drilling and Production

Our development drilling program in the Rocky Mountain region is our principal area of focus. This program is characterized by a high drilling success rate, which has been greater than 97% in each of the last five years, and strong production metrics. We engage in a limited amount of exploratory drilling, having drilled a total of 25 exploratory wells in the past five years. The vast majority of our production comes from a combination of properties that have long production histories and from development drilling. For example, our assets in the Appalachian Basin are principally comprised of wells that have been producing natural gas and oil for decades.

Operational Control and Low Production Costs

By maintaining operational control over the vast majority of our properties, we believe we are able to effectively manage overhead, operating, workover and drilling costs, capital expenditures and the timing of development activities. We believe that our focus on maintaining relatively low-cost operations has provided us with advantages over our competitors, particularly during troughs in the commodity price cycle.

Proven Acquisition Strategy

Throughout our corporate history, we have focused on identifying and evaluating acquisition targets that offer high rates of return. In particular, we have traditionally acquired under-exploited properties where the application of our technical expertise and a limited amount of additional capital has resulted in significant increases in production. Several recent acquisitions have complemented our existing operations and technical expertise, which has allowed us to capture economies of scale and enhance our property portfolio.

Conservative Financial Approach

We have historically incurred only limited amounts of debt and have selectively hedged our exposure to changing commodity prices in order to mitigate risk. We believe that this conservative financial approach has contributed to our long-term success and positions us to capitalize on new opportunities as they develop.

Natural Gas Industry Overview

Natural gas is one of the largest energy sources in the United States. The estimated 21.9 Tcf of natural gas consumed in 2006 represented approximately 22% of the total energy used in the United States. Natural gas is consumed in the United States as follows: 35% by industrial end-users as feedstock for products such as plastic and fertilizer or as the energy source for producing products such as glass; 28% by utilities for the generation of electricity; 21% and 14% by residential and commercial end-users, respectively, for uses including heating, cooling and cooking; and 2% for other users. (Source U.S. Energy Information Administration)

We believe that the market for natural gas will continue to grow in the future. Natural gas burns cleaner than most fossil fuels and produces less greenhouse gas per unit of energy released. Relative to other energy sources, natural gas usage and losses during transportation from source to destination are slight, averaging only about 2% of the natural gas energy. The delivery of natural gas is among the safest means of distributing energy to customers, as the natural gas transmission system is fixed and is located underground.

The deregulation of the natural gas industry and a favorable regulatory environment have resulted in end-users' ability to purchase natural gas on a competitive basis from a greater variety of sources. Increasing international demand for petroleum combined with supply constraints kept oil prices near record high levels throughout 2006 and 2007. Continuing increases in world energy demand appear likely in 2008 and beyond. This makes natural gas more competitive in domestic markets as a replacement for oil and increases the value of domestic natural gas and oil reserves.

We believe that the foregoing factors, together with the increased availability of natural gas as a form of energy for residential, commercial and industrial uses, is likely to increase the demand for natural gas as well as create new markets for natural gas, even at prices that are high by historical standards.

Because local supplies of natural gas are inadequate to meet demand in some sections of the United States, areas including the West Coast and the Northeast import natural gas from producing areas via interstate natural gas pipelines. The cost of transporting natural gas from the major producing areas to markets creates a price advantage for production located closer to the consuming regions. Natural gas producers in the Appalachian Basin and Michigan benefit from proximity to the Northeastern and Midwestern United States markets.

In contrast, much of the production in the Rocky Mountains is transported significant distances to end-user markets. As a result, the price received for natural gas in the Rocky Mountains is generally less than the price received in areas closer to the primary consuming areas. The Rocky Mountain region is believed to hold substantial undeveloped natural gas resources. Recent and planned additions to pipeline capacity in the region have made the area more attractive for development. Although in the near term, natural gas from the region will generally sell for less than natural gas in the Appalachian and Michigan Basins, development costs per Mcfe may be less.

Operations

Exploration and Development Activities

Our development activities focus on identifying and drilling new productive wells, acquiring existing producing wells from other operators, and maximizing the value of our current properties through infill drilling, recompletions, and other production enhancements.

Prospect Generation

Our staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. These geologists have decades of cumulative experience evaluating prospects and drilling natural gas and oil wells. 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, other companies and individuals actively drilling in the regions being evaluated. From this information our 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, farmouts and other development rights in these prospective areas. In order to secure a lease, we usually pay a lease bonus and annual rental payments, converting, upon initiation of production, to a royalty. In addition, we pay overriding royalty payments to third parties in conjunction with the acquisition of drilling rights initially leased by others. As of September 30, 2007, we had leasehold rights to approximately 236,220 acres available for development.

Drilling Activities

When prospects have been identified, leased and all regulatory approvals obtained, we develop these properties by drilling wells. In 2006, we drilled a total of 222 development wells, of which 216 wells were designated successful. As of December 31, 2006, 82 of the 216 successful wells were awaiting natural gas pipeline connection. As of September 30, 2007, all of the wells awaiting pipeline connection at December 31, 2006, were connected and turned in line. During the nine months ended September 30, 2007, we drilled a total of 258 developmental wells, of which 250 wells were designated as successful. As of September 30, 2007, 103 of the 250 successful wells were awaiting natural gas pipeline connection. Typically, we will act as driller-operator for these prospects, frequently selling interests in the wells to PDC-sponsored partnerships and other entities that are interested in exploration or development of the prospects. We retain a working interest in each well we drill.

We also drilled nine exploratory wells in 2006, eight (including one pending determination as of December 31, 2006) were determined to be productive and one was determined to be dry. Costs related to the dry hole of \$1.3 million were expensed in 2006. We drilled six exploratory wells during the nine months ended September 30, 2007 and one was determined to be productive and five were determined to be dry. Costs related to these dry holes of \$2.0 million have been expensed during the nine months ended September 30, 2007. We plan to conduct additional exploratory drilling activities in during the remainder of 2008.

	Development Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
2002	70	13.7	70	13.7		
2003	110	28.5	110	28.5		
2004	157	43.0	153	42.4	4	0.6
2005	234	103.4	232	102.0	2	1.4
2006	222	134.4	216	129.8	6	4.6
Nine Months Ended September 30, 2007	258	217.7	250	210.3	8	7.4
Total	1,051	540.7	1,031	526.7	20	14

Much of the work associated with drilling, completing and connecting wells, including drilling, fracturing, logging and pipeline construction is performed under our direction by subcontractors specializing in those operations, as is common in the industry. When judged advantageous, we will acquire material and services used by us 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.

The following tables summarize our development and exploratory drilling activity for the last five years and for the nine months ended September 30, 2007. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells.

	Exploratory Wells Drilled					
	Total		Productive		Dry	
	Drilled	Net	Drilled	Net	Drilled	Net
2002						
2003	1	1.0			1	1.0
2004	1	1.0			1	1.0
2005	8	7.3	3	2.3	5	5.0
2006	9	3.3	8	2.8	1	0.5
Nine Months Ended September 30, 2007	6	2.7	1	0.2	5	2.5
	25	15.3	12	5.3	13	10

Financing of Our Drilling and Development Activities

We conduct development drilling activities for our own account and act as operator for other owners. When conducting activities for our own account, we use cash flow from operations and capital provided from our long term credit facility to fund our share of operations.

Drilling and Development Activities Conducted For Our Drilling Partnerships

In addition to wells and interests in wells that we drill for ourself, we also act as operator for other natural gas and oil owners. Historically, these other owners have included individuals, corporations, partnerships formed by non-affiliated parties and other investors. Currently, our drilling partners consist primarily of public and partnerships that we sponsor. We contribute a cash investment to purchase an interest in the drilling and development activities and serve as the managing general partner for each partnership; accordingly, we are subject to substantial cash commitments at the closing of each drilling partnership.

In 1984, we began sponsoring drilling partnerships. The drilling partnerships had \$90 million in subscriptions in 2006, \$116 million in subscriptions in 2005, and \$100 million in subscriptions in 2004. During 2006, we sponsored one drilling partnership to which we contributed \$38.9 million and received a 37% working interest in the partnership. In August 2007, we sponsored a drilling partnership to which we are obligated to contribute \$38.7 million and in which we will receive a 37% working interest. While we received funds pursuant to drilling contracts in the years indicated, we recognize revenues from drilling operations on the percentage of completion method as the wells are drilled, rather than when funds are received. Substantially all of our drilling and development funds are now received from partnerships in which we serve as managing general partner. However, because wells produce for a number of years, we continue to serve as operator for a number of unaffiliated parties.

Typically we enter into a development agreement with an investor partner, pursuant to which we agree 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 becomes owner of a working interest in the well.

Our drilling contracts with our investor partners have historically taken many different forms. Beginning with the last drilling partnership of 2005 (for which revenue generating activities did not commence until early 2006), partnership wells are drilled on a cost-plus basis, whereby we bill investors for the actual cost of the wells plus an agreed upon mark-up above the costs. In the past our drilling contracts could be classified as on a footage-based rate, whereby we received drilling and completion payments based on the depth of the well. Apart from our initial contribution, we may also purchase an additional working interest in the partnership properties. 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 other investors participate. The level of our drilling and development activity is dependent upon the amount of subscriptions in our public drilling partnerships and investments from other partnerships or other joint venture partners. Accepting investments from third-party investors and PDC-sponsored partnerships enables us to diversify our holdings, thereby reducing the risk of our investments. Our management believe that investments in drilling activities, whether through drilling partnerships or other sources, are influenced in part by the favorable treatment that such limited partner investments receive under the federal income tax laws. No assurance can be given that we will continue to have access to funds generated through these financing vehicles or that the favorable tax treatment will continue.

Purchases of Producing Properties

In addition to drilling new wells, we continue to pursue opportunities to purchase existing wells from other owners, as well as greater ownership interests in the wells we operate. Generally, outside interests that we purchase include a majority interest in the wells and the right to operate the wells. During 2006, we successfully acquired the stock of Unioil, a small independent producer with

properties primarily in the Wattenberg Field in Colorado, for a total of \$18.6 million. In addition, in January 2007, we completed the purchase of approximately 144 natural gas and oil wells and 8,160 acres of leaseholds in the Wattenberg Field from EXCO Resources. Also in January 2007, we purchased the outside partnership interests in 44 partnerships which had been 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 28 producing wells and associated undeveloped acreage in Colorado for \$12.0 million. On October 30, 2007, we purchased a majority working interest in approximately 760 natural gas wells located in southwestern Pennsylvania, which were operated by Castle Gas Company, Inc. and included approximately 47.0 Bcfe of internally estimated proved reserves net to the purchased interest and associated pipelines, equipment, real estate and undeveloped acreage.

Production

The following table shows our net production in thousands of barrels, MBbl, of crude oil and in million cubic feet, or MMcf, of natural gas and the costs and weighted average selling prices of oil in barrels (Bbl) and natural gas in thousands of cubic feet (Mcf).

	Nine Months Ended					
	September 30, 2007	2006	Year Ended December 31,			
	2007	2006	2005	2004	2003	2002
Production⁽¹⁾:						
Oil (MBbl)	667	631	439	381	289	227
Natural Gas (MMcf)	15,489	13,161	11,031	10,372	8,712	6,462
Equivalent (MMcfe) ⁽²⁾	19,490	16,949	13,665	12,659	10,449	7,824
Average sales price:						
Oil (per Bbl) ⁽³⁾	\$ 55.78	\$ 59.33	\$ 50.56	\$ 38.00	\$ 29.43	\$ 24.41
Natural gas (per Mcf) ⁽³⁾	\$ 5.20	\$ 5.91	\$ 7.29	\$ 5.30	\$ 4.58	\$ 2.65
Equivalent average sales price (per Mcfe)	\$ 6.04	\$ 6.80	\$ 7.51	\$ 5.49	\$ 4.63	\$ 2.90
Average production cost (lifting cost)						
Per equivalent (Mcfe) ⁽⁴⁾	\$ 1.33	\$ 1.23	\$ 1.19	\$ 1.12	\$ 0.93	\$ 0.76

- (1) Production as shown in the table is net to us and is determined by multiplying the gross production volume of properties in which we have an interest by the percentage of our leasehold or other property interest.
- (2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one barrel 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. The above table does not include the results of derivative transactions.
- (4) Production costs represent natural gas and oil operating expenses which include severance and ad valorem taxes as reflected in our financial statements.

Natural Gas Sales

We generally sell the natural gas that we produce under contracts with monthly pricing provisions. Virtually all of our contracts include provisions wherein prices change monthly with changes in the market 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 sell our natural gas to industrial end-users, utilities, other natural gas marketers, and other wholesale natural gas purchasers. During 2006, the natural gas that we produced was sold at prices ranging from \$2.26 to \$15.70 per Mcf, depending upon well location, the date of the sales contract and other factors. The weighted net average price of natural gas we sold during 2006 was \$5.91 per Mcf. During the nine months ended September 30, 2007, the natural gas we produced was sold at prices ranging from \$1.68 to \$18.56 per Mcf, depending upon well location, the date of the sales contract and other factors. The weighted net average price of the natural gas we sold during the nine months ended September 30, 2007 was \$5.20 per Mcf.

In general, we, together with our marketing subsidiary, RNG, 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. 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.

Oil Sales

The majority of our wells in the Wattenberg field in Colorado and in North Dakota produce oil in addition to natural gas. As of December 31, 2006, oil represented about 13% of our total equivalent reserves and accounted for approximately 33% of our natural gas and oil sales for the year ended December 31, 2006.

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. During 2006, we produced oil that sold at prices ranging from \$53.75 to \$71.77 per barrel, depending upon the location and quality of oil. In 2006, the weighted net average price per barrel of oil we sold was \$59.33. During the nine months ended September 30, 2007, the oil we produced sold at prices ranging from \$40.60 to \$66.49 per barrel, depending on the location and quality of oil. The weighted average net price per barrel of oil sold by us during the same period was \$55.78.

Natural Gas Marketing

Our natural gas marketing activities involve the purchase of natural gas from other producers and the sale of that natural gas along with the natural gas we produce. We believe that in a deregulated market, successful natural gas marketing is an essential component of profitable operations. 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.

The natural gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual customers.

RNG, our wholly owned subsidiary, is a natural gas marketing company that specializes in the purchase, aggregation and sale of natural gas production in our Eastern operating areas. RNG markets the natural gas we produce and also purchases natural gas from other producers and resells to utilities, end users or other marketers. The employees of RNG 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 from PDC-operated wells. The gas is marketed to natural gas utilities, industrial and commercial customers as well as other marketers, either directly through our gathering system, or through transportation services provided by regulated interstate pipeline companies.

Commodity Risk Management Activities

We utilize commodity based derivative instruments to manage a portion of the exposure to price volatility stemming from our natural gas and oil sales and marketing activities. These instruments consist of over-the-counter swaps and options, NYMEX-traded natural gas futures and option contracts for Appalachian and Michigan production, Colorado Interstate Gas Index and Panhandle Eastern Pipeline based contracts for Colorado natural gas production, and NYMEX-traded oil futures and option contracts for Colorado oil production. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price protection for committed and anticipated natural gas and oil purchases and sales, generally forecasted to occur within the next two- to three-year period. Our policies prohibit the use of natural gas or oil futures or options for speculative purposes, and permit utilization of derivatives only if there is an underlying physical position.

RNG has extensive experience with the use of cash-settled 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 those 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. RNG also enters into back-to-back fixed-price purchases and sales contracts with counterparties. These fixed physical contracts meet the FAS 133 definition of a derivative. Both types of derivatives (i.e., the physical deals and the cash settled contracts) are carried on the balance sheet at fair value with changes in fair values recognized currently in the income statement.

We are subject to price fluctuations for natural gas sold in the spot market and under market index contracts. 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. We economically manage the price risk on only a portion of our anticipated production, so some of our production is subject to the full fluctuation of market pricing.

Well Operations

At September 30, 2007, we had an interest in approximately 1,900 wells in the Rocky Mountain Region, 1,400 wells in the Appalachian Basin and 200 wells in the Michigan Basin. Our ownership interest in these wells range up to 100% and as of September 30, 2007, on average, we had approximately 64.2% ownership interest in the wells we operated.

We are paid a monthly operating fee for each well we operate for the portion of the wells owned by others, including the partnerships that we sponsor. 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. We may also receive additional compensation, at competitive rates, for special non-recurring activities, such as reworks and recompletions.

Transportation

Natural gas wells are connected by pipelines to natural gas markets. Over the years, we have developed, owned and operated 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.

Governmental Regulation

While the price of natural gas is set by the market, other aspects of our business and the natural gas industry in general are heavily regulated. The availability of a ready market for natural gas production depends on several factors beyond our control. These

factors include regulation of natural gas production, federal and state regulations governing environmental quality and pollution control, the amount of natural gas 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, to protect rights to produce natural gas between 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 United States, the federal and state governments own a large percentage of the land and the rights to develop natural gas and oil. Recently we have increased our positions in these types of leases. 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 United States 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 taxation, 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. Also, regulated matters include:

bond requirements in order to drill or operate wells;

the location of a well;

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.

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 ratatability 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 have increased 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, or FERC, jurisdiction over natural gas transportation was unaffected by the Decontrol Act. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at market prices, there are a number of proposed bills in the United States Congress to reenact price controls or impose windfall profits or similar taxes in the future on natural gas and oil prices. The passage of one of those bills or similar legislation could have the effect of reducing the price we receive for our production, or substantially increasing the tax burden associated with our production operations.

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 ratemaking 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 natural gas 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.

Additional proposals and proceedings that might affect the natural gas industry occur frequently in Congress, FERC, state commissions, state legislatures, and the courts. The natural gas 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.

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 stricter environmental legislation and regulations could 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 natural gas 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.

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 Federal Clean Water Act 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.

Our expenses relating to preserving the environment during 2006 and the nine months ended September 30, 2007 were not significant in relation to operating costs and we expect no material change in 2008. Environmental regulations have had no materially adverse effect on our operations to date, but no assurance can be given that environmental 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.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including 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 toxic 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 natural gas 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 that is not fully insured could materially adversely affect our operations and financial condition. We cannot predict whether insurance will continue to be available at premium levels that justify its purchase or whether insurance will be available at all.

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 compete with a number of other companies that offer interests in drilling partnerships with a wide range of investment objectives and program structures. Competition for investment capital for drilling programs is intense. 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 2006 and throughout 2007, the industry experienced continued strong demand for drilling services and supplies. This is resulting in increasing costs, and in some cases the demand for supplies and services exceeds the available supplies. This can result in higher well costs and delays in the execution of planned drilling operations. Factors affecting competition in the natural gas and oil 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 natural gas and oil industry in each of the listed areas. Nevertheless, our business, financial condition, and results of operations could be materially adversely affected by competition.

Legal Proceedings

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 and that the ultimate results of such other proceedings will not have a material adverse effect on our financial position or results of operations.

On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against us in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells we operated in the State of Colorado. The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for the alleged underpayment of royalties we made to the plaintiff pursuant to leases. We moved the case to Federal Court on June 28, 2007, and on July 10, 2007, we filed our answer and affirmative defenses. A scheduling order has not been issued at this time and no discovery has taken place.

On December 3, 2007, Ted Amsbaugh, Donald L. Kretsch and Barbara H. Kretsch, as Co-Trustees of the Kretsch Living Trust, and Buddy Baker, individually and on behalf of others similarly situated, filed a class action complaint against us in the United States District Court for the District of Colorado alleging we underpaid royalties in Colorado. Plaintiff filed a motion to join this complaint to the existing class action proceedings discussed above. Given the preliminary stage of these proceedings and the inherent uncertainty in litigation, we are unable to predict the ultimate outcome of these suits at this time.

Employees

As of December 31, 2007, we had 257 employees, including 157 in production and 7 in natural gas marketing, 35 in exploration and development, 37 in finance and accounting, and 21 in administration. Our engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and 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.

Our employees are not covered by a collective bargaining agreement. We consider relations with our employees to be excellent.

MANAGEMENT
Board of Directors and Executive Officers

Our executive officers and directors, their principal occupations for the past five years and additional information is set forth below.

Name	Age	Position(s)	Director	Directorship Term
			Since	Expires
Steven R. Williams	56	Chairman, Chief Executive Officer and Director	1983	2009
Richard W. McCullough	56	Vice Chairman, Chief Financial Officer and Director	2007	2008
Thomas E. Riley	54	President and Director	2004	2010
Darwin L. Stump	52	Chief Accounting Officer		
Eric R. Stearns	50	Executive Vice President, Exploration and Production		
Daniel W. Amidon	47	General Counsel and Secretary		
Vincent F. D. Annunzio	55	Director	1989	2010
Jeffrey C. Swoveland	52	Director	1991	2008
Kimberly Luff Wakim	49	Director	2003	2009
David C. Parke	41	Director	2003	2008
Anthony J. Crisafio	54	Director	2006	2009
Joseph E. Casabona	64	Director	2007	2008
Larry F. Mazza	47	Director	2007	2008

Steven R. Williams was elected Chairman and Chief Executive Officer in January 2004. Mr. Williams served as President from March 1983 until December 2004 and has been a Director of PDC since 1983.

Richard W. McCullough was elected Vice Chairman of our Board of Directors in December of 2007, was appointed Chief Financial Officer in November 2006 and also served as our Treasurer from November 2006 until October 2007. Prior to joining us, Mr. McCullough served as president and chief executive officer of Gasource, LLC, Dallas, Texas, a marketer of long-term, natural gas supplies. From 2001 to 2003, Mr. McCullough served as an investment banker with J.P. Morgan Securities, Atlanta, Georgia, and served in the public finance utility group supporting bankers nationally in all natural gas matters. Additionally, Mr. McCullough has held senior positions with Progress Energy, Deloitte and Touche, and the Municipal Gas Authority of Georgia. Mr. McCullough, a CPA, was a practicing certified public accountant for eight years. On December 20, 2007, our Board of Directors selected Mr. McCullough to succeed Mr. Williams as Chief Executive Officer upon Mr. Williams' scheduled 2008 retirement.

Thomas E. Riley was elected Director in January 2004 by the Board of Directors and assumed the position of President in December 2004. Previously, Mr. Riley was appointed Executive Vice President of Production, Natural Gas Marketing and Business Development in November 2003. Prior thereto, Mr. Riley served as Vice President Gas Marketing and Acquisitions of PDC since April 1996. Prior to joining us, Mr. Riley was president of Riley Natural Gas Company, a natural gas marketing company which we acquired in April 1996.

Darwin L. Stump was appointed Chief Accounting Officer in November 2006. Mr. Stump has been an officer of PDC since April 1995 and held the position of Chief Financial Officer and Treasurer from 2003 until November 2006. Previously, Mr. Stump served as Corporate Controller from 1980 until November 2003. Mr. Stump, a CPA, was a senior accountant with Main Hurdman, Certified Public Accountants prior to joining us.

Eric R. Stearns was appointed Executive Vice President of Exploration and Production in December 2004. Prior to his current position, Mr. Stearns was Executive Vice President of Exploration and Development since November 2003, having previously served as Vice President of Exploration and Development since April 1995. Mr. Stearns joined us as a geologist in 1985 after working for Hywell, Incorporated and for Petroleum Consultants.

Daniel W. Amidon was appointed General Counsel in July 2007. Prior to his current position, Mr. Amidon was employed by Wheeling-Pittsburgh Steel Corporation beginning in July 2004; he served in several positions including General Counsel and Secretary. Prior to his employment with Wheeling-Pittsburgh Steel, Mr. Amidon worked for J&L Specialty Steel Inc. from 1992 through July 2004 in positions of increasing responsibility, including General Counsel and Secretary. Mr. Amidon practiced with the Pittsburgh law firm of Buchanan Ingersoll PC from 1986 through 1992.

Vincent F. D. Annunzio has served as president of Beverage Distributors, Inc. located in Clarksburg, West Virginia since 1985.

Jeffrey C. Swoveland is the chief operating officer of Coventina Healthcare Enterprises, a medical device company specializing in therapeutic warming and multi-modal treatment systems used in the treatment, rehabilitation and management of pain since May 2007. Previously, Mr. Swoveland served as the chief financial officer of Body Media, a life-science company specializing in the design and development of wearable body monitoring products and services, from September 2000 to May 2007. Prior thereto, Mr. Swoveland held various positions, including vice president of finance, treasurer and interim chief financial officer, with Equitable Resources, Inc., a diversified natural gas company, from 1997 to September 2000. Since January 2006, Mr. Swoveland has served as a member of the board of directors of Linn Energy, LLC, a public, independent natural gas and oil company.

Kimberly Luff Wakim, an Attorney and Certified Public Accountant, is a partner with the law firm Thorp, Reed & Armstrong LLP. Ms. Wakim joined Thorp Reed & Armstrong LLP in 1990.

David C. Parke is a managing director in the investment banking group of Boenning & Scattergood, Inc., West Conshohocken, Pennsylvania, a full-service investment banking firm. Prior to joining Boenning & Scattergood in November 2006, he was a director with Mufson Howe Hunter & Company LLC, Philadelphia, Pennsylvania, an investment banking firm, from October 2003 to November 2006. From 1992 through 2003, Mr. Parke was director of corporate finance of Investec, Inc., and its predecessor Pennsylvania Merchant Group Ltd., investment banking companies. Prior to joining Pennsylvania Merchant Group, Mr. Parke served in the corporate finance departments of Wheat First Butcher & Singer, now part of Wachovia Securities, and Legg Mason, Inc., now part of Stifel Nicolaus. Mr. Parke serves as a member of the board of directors of Zunicom, Inc., a public company providing business communication services to the hospitality industry.

Anthony J. Crisafio was elected to the Board in October 2006. Mr. Crisafio, a certified public accountant, serves as an independent business consultant, providing financial and operational advice to businesses and has done so since 1995. He owned two small businesses during the period of 1991 to 2002. Additionally, Mr. Crisafio has served as the chief operating officer of Cinema World, Inc. from 1989 until 1993 and was a partner with Ernst & Young from 1986 until 1989.

Joseph E. Casabona was elected to the Board in October 2007. Mr. Casabona served as Executive Vice President and member of the Board of Directors of Denver based Energy Corporation of America, or ECA, from 1985 to his retirement earlier this year. ECA combines Appalachian Basin natural gas development, deep exploration, marketing, and pipeline gathering and transportation to industrial end users, utility purchasers and other customers with higher risk, higher reward exploratory drilling in Texas and internationally.

Larry F. Mazza was elected to the Board in October 2007. Mr. Mazza has served as Chief Executive Officer of MVB Bank Harrison, Inc., in Bridgeport, West Virginia since March 2005. Prior to the formation of MVB Bank Harrison, Mr. Mazza served as Senior Vice President Retail Banking Manager for BB&T in West Virginia, where he was employed from June 1986 to March 2005.

Corporate Governance

In January 2005, we adopted Corporate Governance Guidelines to promote the effective functioning of our Board of Directors and related committees.

Board of Directors

Our By-Laws provide that the number of members of the Board of Directors shall be designated from time to time by a resolution of the Board. The Board has most recently set the number of directors at ten. The Board shall be divided into three separate classes of directors which are required to be as nearly equal in number as practicable. At each annual meeting of stockholders one class of directors, whose term expires, will be elected to a term of three years. The classes are staggered so that the term of one class expires each year. There is no family relationship between any of our directors or executive officers. There are no arrangements or understandings between any director or officer and any other person pursuant to which the person was selected as an officer.

Director Independence

We have determined that all of our directors, other than Messrs. Williams, McCullough and Riley, are independent under NASDAQ Marketplace Rule 4200 and the Exchange Act.

Committees of the Board

The following table identifies the current membership and chair of the five standing committees of the Board:

Name	Audit	Compensation	Executive	Nominating/	Planning/
				Corporate Governance	Finance
Jeffrey C. Swoveland	Chair		Member		Member
Kimberly Luff Wakim	Member	Member		Member	
Vincent F. D. Annunzio		Member	Member	Chair	
David C. Parke	Member	Chair		Member	Chair
Anthony J. Crisafio	Member	Member			
Steven R. Williams			Chair		
Thomas E. Riley			Member		Member
Joseph E. Casabona	Member				Member
Larry F. Mazza		Member		Member	
Richard W. McCullough					

The Audit Committee of the Board is comprised entirely of persons whom the Board has determined to be independent under NASDAQ Rule 4200(a)(15). Mr. Swoveland chairs the committee; other audit committee members are Ms. Wakim, Mr. Parke and Mr. Crisafio. The Board has determined that Mr. Swoveland and the other Audit Committee members, with the exception of Mr. Parke, qualify as audit committee financial experts as defined by SEC regulations and are all, without exception, independent of management. The audit committee's purpose is to assist the Board in monitoring the integrity of our financial reporting process, systems of internal controls and financial statements. Additionally, the committee is directly responsible for the appointment, compensation and oversight of the independent auditors for the purpose of preparing or issuing an audit report or related work and to assess the need for an internal audit function and recommend its establishment when deemed appropriate.

The independent directors conduct meetings without the presence of management at each scheduled Board meeting. Mr. Swoveland serves as Presiding Independent Director of the Board.

Code of Ethics

In January 2003, we adopted our Code of Business Conduct and Ethics, as amended, that is applicable to all of our directors, officers, employees, agents and representatives and consultants. Our principal executive officer, principal financial officer and principal accounting officer are subject to additional specific provisions under the Code of Conduct. Our Code of Conduct is posted on our website at www.petd.com. In the event of an amendment to, or a waiver of, including an implicit waiver, the Code of Conduct, we will disclose the information on our internet website.

CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Policies and Procedures with Respect to Transactions with Related Persons

Our board of directors has adopted a written policy for the review, approval and ratification of transactions that involve related parties and potential conflicts of interest.

The related party transaction policy applies to each of our directors and executive officers, any nominee for election as a director, any security holder who is known to own more than five percent of our voting securities, any immediate family member of any of the foregoing persons and any corporation, firm or association in which one or more of our directors are directors or officers, or have a substantial financial interest.

Under the related party transaction policy a related person transaction is a transaction or arrangement involving a related person in which our company is a participant or that would require disclosure in our filings with the SEC as a transaction with a related person.

The related persons must disclose to the Audit Committee any potential related person transactions and must disclose all material facts with respect to such interest. All related person transactions will be reviewed by the Audit Committee. In determining whether to approve or ratify a transaction, the Audit Committee will consider the relevant facts and circumstances of the transaction which may include factors such as the relationship of the related person with our company, the materiality or significance of the transaction to us and the business purpose and reasonableness of the transaction, whether the transaction is comparable to a transaction that could be available to us on an arms-length basis, and the impact of the transaction on our business and operations.

During the year ended December 31, 2006, there was no transaction or series of transactions, or any currently proposed transaction, in which the amount involved exceeds \$120,000 and in which any director, executive officer, nominee, holder of more than 5% of our common stock or any member of the immediate family of any of the foregoing persons had or will have a direct or indirect material interest.

Waiver of Potential Conflict of Interest

Jeffery Swoveland, one of our directors, is also a member of the Board of Directors of Linn Energy, LLC, which we refer to as Linn, an oil and gas development and acquisition company. Linn owns and operates properties around the country, but is focused on Oklahoma and the Texas panhandle.

On November 17, 2007, our Board of Directors, consistent with section 12 of our Code of Business Conduct and Ethics, which we refer to as our Code of Ethics, waived the restriction contained in the Code of Ethics to the extent that it may prohibit such directorship by Mr. Swoveland.

DESCRIPTION OF INDEBTEDNESS

Senior Secured Credit Facility

General

On November 4, 2005, we entered into an amended and restated senior credit agreement with a syndicate of lenders led by JPMorgan Chase Bank, N.A., as administrative agent, and BNP Paribas, as syndication agent and joint lead arranger. Pursuant to amendments on August 9, 2007, October 16, 2007, and November 6, 2007, Wachovia Bank, National Association, Guaranty Bank, FSB, Bank of Oklahoma, Morgan Stanley Bank, Royal Bank of Canada and The Royal Bank of Scotland, plc. were added as lenders. The senior credit agreement is a five-year senior revolving credit facility that provides for as much as \$400 million in borrowing capacity, depending on a number of factors, including the projected value of our proven natural gas and oil reserves. The borrowing base is redetermined on a semi-annual basis, but may be reduced upon the occurrence of certain events, including the issuance of certain indebtedness. As a result of our obtaining additional properties in connection with the Castle acquisition, on November 21, 2007 we received confirmation from the lenders under our senior credit agreement that the borrowing base was increased by another \$25 million to a total of \$300 million. However, as a result of our previously disclosed sale of a portion of our North Dakota properties, the borrowing base was reduced to \$295 million effective as of December 27, 2007. Our borrowing base under the credit facility as of December 31, 2007 remained at \$295 million. We are required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the credit facility.

As of September 30, 2007, the outstanding balance under the credit facility was \$172 million, which is subject to an adjusted LIBOR of 7.5625%. Borrowings under the credit facility will mature on November 4, 2010. The terms of the facility are as described below.

Guarantees and Security

Our subsidiaries Riley Natural Gas Company, Unioil and PA PDC, LLC have guaranteed our obligations under the credit facility. Borrowings under the credit facility are secured by a pledge of the stock of certain of our subsidiaries and mortgages on certain of our natural gas and oil properties. The various drilling partnerships sponsored by us for which we act as managing general partners are not guarantors under the credit facility.

Interest and Fees

The interest under the credit facility is payable at rates per annum based on, at our option, (1) the alternative base rate or (2) adjusted LIBOR. The alternative base rate is a rate per annum equal to the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus 0.5%. Alternative base rate borrowings are assessed an additional margin spread of up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of up to 1.875%. The margin spread charges are based upon the outstanding balance under the credit facility. No principal payments are required until the credit facility expires on November 4, 2010. We have the right under the senior credit agreement to prepay our borrowings under the credit facility without premium or penalty.

Covenants and Events of Default

The senior credit agreement 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, (g) enter into transactions with our affiliates, (h) change the character of our business, (i) engage in hedging activities unless certain requirements are satisfied, (j) issue certain types of stock, and (k) make certain amendments to our organizational documents. The senior credit agreement 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. In addition, we are required to comply with certain financial tests and maintain certain financial ratios. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, and (b) not to exceed a maximum leverage ratio.

The senior credit agreement also includes customary representations, warranties and events of default relating to (a) non-payment of principal, interest or fees, (b) violation of covenants, (c) inaccuracy of representations and warranties in any material respect, (d) failure to pay any material indebtedness, (e) bankruptcy or insolvency events, (f) material and uncured judgments and (g) a change of control. An event of default under the senior credit agreement will permit the lenders to accelerate the maturity of the indebtedness under the facility, and may result in one or more cross-defaults under our other indebtedness. Similarly, a default generally under the agreements governing any debt securities we may offer and sell from time to time will constitute an event of default under the senior credit agreement.

Recent Waivers

As of June 30, 2007 and September 30, 2007, we were not in compliance with the current ratio covenant under our senior credit agreement. In connection with each of the August 2007 and October 2007 amendments of the senior credit agreement, we received a waiver from the lenders under the senior credit agreement for the current ratio covenant violation. The August 2007 amendment increased all margin spreads by 0.375% for as long as we are in non-compliance with the current ratio covenant. In addition, in August 2007, we received a waiver from the lenders under the senior credit agreement related to our delay in the delivering to the lenders our March 31, 2007 interim condensed consolidated financial statements on June 30, 2007. The October 2007 amendment extended the waiver related to the current ratio covenant violation until the earlier of (i) October 1, 2008 or (ii) the completion of a debt or equity offering that results in our receipt of net proceeds of not less than \$200.0 million, which we refer to as a capital markets event.

On November 21, 2007, we received a waiver from the lenders under the senior credit agreement with respect to the covenants requiring our delivery of specified mortgages and other evidences of security and related opinions and other evidences of title. As of December 31, 2007 (the expiration date of the waiver), we were in compliance with these covenants.

GLOSSARY OF TERMS

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

Bbl One barrel, or 42 U.S. gallons of liquid volume.

Bcf One billion cubic feet.

Bcfe One billion cubic feet of natural gas equivalent.

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

Credit Facility A line of credit provided by a group of banks, secured by natural gas and oil properties.

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

Division order A contract setting forth the interest of each owner of a natural gas and oil property, which serves as the basis on which the purchasing company pays each owner's respective share of the proceeds of the natural gas and oil purchased.

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

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

Gross 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 that may, depending on the horizon, result in increased production rates and greater ultimate recoveries of hydrocarbons.

MBbls One thousand barrels.

Mcf One thousand cubic feet.

Mcfe One thousand cubic feet of natural gas equivalent, based on a ratio of 6 Mcf for each barrel of oil, which reflects the relative energy content.

MMbtu One million British thermal units. One British thermal unit is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

MMcf One million cubic feet.

MMcfe One million cubic feet of natural gas equivalent.

Natural gas liquids Liquid hydrocarbons that have been extracted from natural gas, such as ethane, propane, butane and natural gasoline.

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

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

NYMEX New York Mercantile Exchange, the exchange on which commodities, including crude natural gas and oil futures contracts, are traded.

Oil Crude oil or condensate.

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

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. This value is 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) depreciation, depletion and amortization.

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.

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

Proved reserves The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, such as, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

Proved undeveloped reserves (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 the producer reenters a well to complete (i.e., perforate) a new formation from that in which a well has previously been completed.

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.

SEC The United States Securities and Exchange Commission.

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.

Tcf One trillion cubic feet.

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.

Working interest An interest in a 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 net 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.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Date: January 14, 2008

PETROLEUM DEVELOPMENT CORPORATION

By: /s/ Richard W. McCullough
Name: Richard W. McCullough
Title: Vice Chairman and Chief Financial Officer