PETROLEUM DEVELOPMENT CORP
Form 10-K
February 27, 2009

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

FORM 10-K

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

For the fiscal year ended December 31, 2008

or

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

For the transition period from __________ to _________

Commission File Number 000-07246

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

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

120 Genesis Boulevard
Bridgeport, West Virginia 26330
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (304) 842-3597

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $.01 per share	NASDAQ Global Select Market

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

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

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

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

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2008, was $965,929,153 (based on the then closing price of $66.49).

As of February 23, 2009 there were 14,868,158 ares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form is incorporated by reference to our definitive proxy statement to be filed pursuant to Regulation 14A for our 2009 Annual Meeting of Shareholders.

PETROLEUM DEVELOPMENT CORPORATION
2008 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

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

GLOSSARY OF OIL AND NATURAL GAS TERMS

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

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934 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 natural gas production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management's strategies, plans and objectives. However, these are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of, natural gas and oil, and actual outcomes may differ materially from the results and outcomes discussed in the forward-looking statements. Important factors that could cause actual results to differ materially from the forward looking statements include, but are not limited to:

- changes in production volumes, worldwide demand, and commodity prices for oil and natural gas;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability and cost of capital to us;
- risks incident to the drilling and operation of natural gas and oil wells;
- future production and development costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States of America ("U.S.");
- the effect of natural gas and oil derivatives activities;
- conditions in the capital markets; and
- losses possible from pending or future litigation.

Further, we urge you to carefully review and consider the disclosures made in this report, including the risks and uncertainties that may affect our business as described herein under Item 1A, Risk Factors, and our other filings with the Securities and Exchange Commission ("SEC"). We caution you not to place undue reliance on forward-looking statements, which speak only as of the date of this report. We undertake no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events.

ITEM 1. BUSINESS

General

We are an independent energy company engaged in the exploration, development, production and marketing of oil and natural gas. Since we began oil and natural gas 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.

As of December 31, 2008, we owned interests in approximately 4,712 gross, 3,259 net, wells located primarily in the Rocky Mountain Region and the Appalachian and Michigan Basins with 753 billion cubic feet equivalent, or Bcfe, of net proved reserves, of which 88% was natural gas and 12% was oil.

During 2008, our production was 38.7 Bcfe, averaging 106.1 MMcfe per day, a 38.5% increase over 76.6 MMcfe per day produced in 2007. We replaced our 2008 production with 106 Bcfe of new proved reserves, net of dispositions, for a reserve replacement rate of 274%. Reserve replacement through the drillbit was 104 Bcfe, or 268% of production, and reserve replacement through acquisitions was 2 Bcfe, or 6% of production. Proved reserves grew 9.8% during 2008, from 686 Bcfe to 753 Bcfe, of which 44% were proved developed reserves.

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We make available free of charge on our website at www.petd.com our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to these reports as soon as reasonably practicable after we electronically file these reports with, or furnish them to, the SEC. We will also make available to any shareholder, without charge, a copy of our Annual Report on Form 10-K, or any other filing, as filed with the SEC, by mail. For a mailed copy of a report, you may contact Petroleum Development Corporation, Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call toll free (800) 624-3821.

In addition to our SEC filings, other information, including our press releases, Bylaws, Committee Charters, Code of Business Conduct and Ethics, Shareholder Communication Policy, Director Nomination Procedures and the Whistleblower Hotline, is also available on our website. However, the information available on our website is not part of this report and is not hereby incorporated by reference.

Business Strategy

Our primary objective is to continue to increase shareholder value through the growth of our reserves, production, net income and cash flow. To achieve meaningful increases in these key areas, we maintain an active drilling program that focuses on low risk development of our oil and natural gas 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 and the Appalachian, Michigan and Fort Worth Basins. In the Rocky Mountain Region, we focus on developmental drilling in Northeastern Colorado, or NECO, the Wattenberg Field (both located in the DJ Basin), the Grand Valley Field, Piceance Basin, and additional limited development in North Dakota. We drilled 379 gross, 333.4 net, wells in 2008, compared to 349 gross, 276.3 net, wells in 2007. In addition, we seek to maximize the value of our existing wells through a program of well recompletions and refractures. During 2008, we recompleted and/or refraced a total of 125 wells compared to 181 in 2007. In 2009, with a limited inventory of available recompletion opportunities, we plan to recomplete and/or refrac 40 wells in the Appalachian Basin.

We believe that we will be able to continue to drill a substantial number of new wells on our current undeveloped properties. As of December 31, 2008, we had leases or other development rights to approximately 224,800 undeveloped acres, of which approximately 188,000 acres, or 83.5%, were in the Rocky Mountain Region. We plan to drill approximately 166 gross, 144.1 net, wells in 2009, excluding exploratory wells. To support future development activities, we have conducted exploratory drilling in the past and plan to drill seven wells in 2009, primarily in the Appalachian Basin. The goal of the exploration program is to develop new areas for us to include in our future development drilling activity.

Strategically Acquire

Our acquisition efforts focus on producing properties that have a significant undeveloped acreage component. When weighing potential acquisitions, we prefer properties that have most of their value in producing wells, behind the pipe reserves or high quality proved undeveloped locations. Historically, acquisitions have offered efficiency improvements through economies of scale in management and administration costs. During the period December 2006 through October 2007, we completed three acquisitions of assets or companies in our core operating area of the Wattenberg Field in Colorado and acquired assets in southwestern Pennsylvania within close proximity to our existing assets in the Appalachian Basin. We had no significant acquisitions of properties in 2008. We expect to continue to evaluate acquisition opportunities. See Note 14, Acquisitions, to our accompanying consolidated financial statements included in this report.

Manage Risk

We seek opportunities to reduce the risk inherent to our business in the oil and natural gas 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 benefit from operational diversity in the Rocky Mountain Region by maintaining significant activity and production in three separate areas, including the Grand Valley Field of the Piceance Basin in western Colorado, the Wattenberg Field in north central 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. We expect that future activities may include some level of exploratory drilling when the economic environment and commodity price models justify such risks. We view exploratory activities as having the potential to identify new development opportunities at a cost competitive to the current cost of acquiring proven locations.

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To help manage the risks associated with the oil and natural gas industry, we maintain a conservative financial approach and proactively employ strategies to reduce the effects of commodity price volatility. We also believe that successful oil and natural gas marketing is essential to risk management and profitable operations. To further this goal, we utilize Riley Natural Gas, or RNG, a wholly-owned subsidiary, to manage the marketing of our oil and natural gas and our use of oil and natural gas commodity derivatives as risk management tools. This allows us to maintain better control over third party risk in sales and derivative activities. We use oil and natural gas derivatives contracts primarily to reduce the effects of volatile commodity prices. We currently have derivative contracts in place on a significant portion of our production; however, pursuant to our derivative policy, all volumes for derivatives contracts are limited to 80% of our future production from producing wells at the time we enter into the derivative contracts, with the exception of put contracts for which volumes are not limited. As of December 31, 2008, we had oil and natural gas hedges in place covering 52% of our expected oil production and 62% of our expected natural gas production in 2009. Further, while our derivative instruments are utilized to manage the impact of price volatility of our oil and natural gas production, they do not qualify for use of hedge accounting under the terms of SFAS No. 133, requiring us to recognize changes in the fair value of our derivative positions in earnings each reporting period and, therefore, resulting in the potential for significant earnings volatility. See Note 1, Summary of Significant Accounting Polices – Derivative Financial Instruments, to our accompanying consolidated financial statements included in this report.

Business Segments

We divide our operating activities into four segments:

- oil and gas sales;
- natural gas marketing activities;
- well operations and pipeline income; and
- oil and gas well drilling operations.

See Note 16, Business Segments, to our accompanying consolidated financial statements included in this report.

Oil and Gas Sales

Our oil and gas sales segment is our largest business segment based on revenue. This segment reflects revenues and expenses from production and sale of oil and natural gas. During 2008, approximately 84.8% of our oil and gas sales revenue was generated by the Rocky Mountain Region, 10.9% by the Appalachian Basin and 4.3% by the Michigan Basin. As of the end of 2008, our total proved reserves were located as follows: Rocky Mountain Region 82%, Appalachian Basin 15% and Michigan 3%. The majority of our undeveloped acreage is in the Rocky Mountain Region, where we focused our 2008 drilling activities. This segment represents approximately 133% of our income before income taxes for the year ended December 31, 2008.

Natural Gas Marketing Activities

Our natural gas marketing activities segment is comprised of our wholly-owned subsidiary, RNG, through which we purchase, aggregate and resell natural gas produced by us and others. This allows us to diversify our operations beyond natural gas drilling and production. Through RNG, we have established relationships with many of the natural gas producers in the Appalachian Basin and we have gained significant expertise in the natural gas end-user market. We do not take speculative positions on commodity prices, and we employ derivative strategies to manage the financial effects of commodity price volatility. Our natural gas marketing segment represented approximately 1% of our income before income taxes for the year ended December 31, 2008.

Well Operations and Pipeline Income

We operate approximately 95.5% of the wells in which we own a working interest. With respect to wells in which we own an interest of less than 100%, we charge the other working interest owners, including our drilling partnerships, a competitive fee for operating the well and transporting natural gas. Our well operations and pipeline income segment represented approximately 2% of our income before income taxes for the year ended December 31, 2008.

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Oil and Gas Well Drilling Operations

Our drilling and development segment reflects results of drilling and development activities conducted for affiliated and non-affiliated parties. 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. Beginning with our third sponsored 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 a fixed drilling fee. Prior to our cost-plus drilling arrangements, drilling was conducted on a "footage" basis, where the Company bore the risk of changes in costs. In addition, we have typically purchased a 20% to 37% working interest in the wells developed through these partnerships. In September 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 oil and gas well drilling segment represented approximately 3% of our income before income taxes for the year ended December 31, 2008. In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008. However, a portion of the funds available for drilling from the 2007 partnership were advanced and unexpended at the end of 2007. The majority of these funds were used in 2008 for drilling and completion activities, a portion of which was recognized as income in 2008. The funds remaining as of December 31, 2008, will be used for completion activities to be conducted in 2009. Currently, we do not plan to sponsor a drilling partnership in 2009 and anticipate that our oil and gas well drilling segment's contribution to operating income will decline significantly in 2009.

Areas of Operations

We focus our exploration, development and production efforts in three primary geographic regions:

- Rocky Mountain Region;
- Appalachian Basin; and
- Michigan Basin.

During 2008, we generated approximately 85.6% of our production from Rocky Mountain Region wells, 10.2% of our production from Appalachian Basin wells and 4.2% 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 predominantly in this area.

Rocky Mountain Region. In 1999, we began operations in the Rocky Mountain Region. Our Rocky Mountain Region is divided into four operating areas: (1) Grand Valley Field, (2) Wattenberg Field, (3) NECO area and (4) North Dakota area. Our Rocky Mountain Region includes approximately 320,000 gross acres of leasehold and 2,408 gross, 1,542 net, oil and natural gas wells in which we own an interest. The general details of each area within the region are further outlined below:

- Grand Valley Field, Piceance Basin, Garfield County, Colorado. We commenced operations in the area in late 1999 and currently own an interest in 285 gross, 158.3 net, natural gas wells. Our leasehold position encompasses approximately 7,900 gross acres with approximately 5,200 net undeveloped acres remaining for development as of December 31, 2008. We drilled 62 gross, 54.4 net, wells in the area in 2008 and produced approximately 12.5 Bcfe net to our interests. Development wells drilled in the area range from 7,000 to 9,500 feet in depth and the majority of wells are drilled directionally from multi-well pads ranging from two to eight or more wells per drilling pad. The primary target in the area is gas reserves, developed from multiple sandstone reservoirs in the Mesaverde Williams Fork formation. Well spacing is approximately ten acres per well.

- Wattenberg Field, DJ Basin, Weld and Adams Counties, Colorado. We commenced operations in the area in late 1999 and currently own an interest in 1,390 gross, 875.2 net, oil and natural gas wells. Our leasehold position encompasses approximately 75,900 gross acres with approximately 24,000 net undeveloped acres remaining for development as of December 31, 2008. We drilled 149 gross, 122.7 net, wells in the area in 2008 and produced approximately 15.4 Bcfe net to our interests. Wells drilled in the area range from approximately 7,000 to 8,000 feet in depth and generally target oil and gas reserves in the Niobrara, Codell and J Sand reservoirs. Well spacing ranges from 20 to 40 acres per well. Operations in the area, in addition to the drilling of new development wells, include the refrac of Codell and Niobrara reservoirs in existing wellbores whereby the Codell sandstone reservoir is fraced a second time and/or initial completion attempts are made in the slightly shallower Niobrara carbonate reservoir.

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- NECO area. DJ Basin, Yuma County Colorado and Cheyenne County, Kansas. We commenced operations in the area in 2003 and currently own an interest in 717 gross, 504 net, natural gas wells. Our leasehold position encompasses approximately 141,600 gross acres with approximately 93,200 net undeveloped acres remaining for development as of December 31, 2008. We drilled 98 gross, 88.1 net, wells in the area in 2008 and produced approximately 5 Bcfe net to our interests. Wells drilled in the area range from approximately 1,500 to 3,000 feet in depth and target gas reserves in the shallow Niobrara reservoir. Well spacing is approximately 40 acres per well. New drilling operations range from exploratory wells to test undrilled, seismically defined, structural features at the Niobrara horizon to development wells targeting known reserves in existing identified features.

- North Dakota, Burke County. We commenced operations in the area in 2006 and currently own an interest in 13 gross, 3.7 net, oil and natural gas wells. We divested the majority of our Bakken project acreage in late 2007 (See Note 13, Sale of Oil and Gas Properties, to our accompanying consolidated financial statements included in this report). Our remaining leasehold encompasses two project areas in Burke County and encompasses approximately 75,100 gross acres with approximately 46,300 net undeveloped acres remaining for development as of December 31, 2008. The eastern area acreage is prospective for development of oil and gas reserves in the Nesson Formation. Nesson development wells are approximately 6,000 feet in depth with single or multiple horizontal legs to 4,000 feet or more in length for a measured length of 10,000 feet or more per leg. The westernmost acreage block is undeveloped and includes approximately 23,600 gross, 16,200 net acres. The western project targets exploratory horizontal drilling to the Midale/Nesson Formation at depths of approximately 6,800 feet with a lateral leg component of up to 6,100 feet. In 2009, we plan to drill up to four exploratory wells on our acreage with funding from an unrelated third party in exchange for an interest in our acreage position.

Appalachian Basin. We have conducted operations in the Appalachian Basin since 1969. Our leasehold position encompasses approximately 140,300 gross acres with approximately 19,400 net undeveloped acres remaining for development as of December 31, 2008. We own an interest in approximately 2,090 gross, 1,566.5 net, oil and natural gas wells in West Virginia, Pennsylvania and Tennessee. We drilled 63 gross/net wells in the area in 2008 and produced approximately 3.9 Bcfe net to our interests. The majority of our Appalachian leasehold is developed on approximately 40 acre spacing. Wells located in this area are approximately 4,500 feet deep and target predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs. We are currently evaluating the potential of the Marcellus Formation in West Virginia and Pennsylvania and have drilled three tests to date in West Virginia, two of which are in line.

Michigan Basin. We began operations in the Michigan Basin in 1997 with the bulk of drilling activity occurring prior to 2002. We own an interest in approximately 210 gross, 146.5 net, oil and natural gas wells that produced 1.6 Bcfe net to our interest in 2008. Wells in the area range from 1,000 to 2,500 feet in depth and produce gas from the Antrim Shale. We drilled 2 gross, 1.6 net, exploratory wells in 2008.

Fort Worth Basin. In addition to those operating areas above, we have an interest in approximately 12,500 gross, 9,100 net undeveloped acres, in Fort Worth Basin, northeastern Erath County, Texas. The leasehold acreage is prospective for the development of oil and natural gas reserves in the Barnett Shale formation at depths of approximately 5,000 feet. Development is typically with a horizontal component of approximately 3,000 feet or more, resulting in an approximate measured length of up to 8,000 feet or more in this area. In 2008, we commenced drilling operations and drilled three exploratory Barnett wells. These wells generated less than 1% of our 2008 production. Based on these results, we recorded impairments of both proved and unproved properties in this area in 2008. We are currently evaluating our future plans in this area and currently have no drilling activity planned in 2009.

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The table below sets forth our productive wells by operating area at December 31, 2008.

	Productive Wells					
	Gas		Oil		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	2,051	1,551.0	39	15.4	2,090	1,566.4
Michigan Basin	203	143.8	7	2.7	210	146.5
Rocky Mountain Region						
Wattenberg	1,365	856.0	25	19.3	1,390	875.3
Grand Valley	285	158.3	-	-	285	158.3
NECO Area	717	504.0	-	-	717	504.0
North Dakota	4	0.4	9	3.3	13	3.7
Wyoming	-	-	3	0.7	3	0.7
Total Rocky Mountain Region	2,371	1,518.7	37	23.3	2,408	1,542.0
Fort Worth Basin	4	4.0	-	-	4	4.0
Total Productive Wells	4,629	3,217.5	83	41.4	4,712	3,258.9

Operations

Prospect Generation

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

On the basis of these models, our land department obtains available natural gas and oil leaseholds, farmouts and other development rights in these prospective areas. In most cases, to secure a lease, we pay a lease bonus and annual rental payments, converting, upon initiation of production, to a royalty. In addition, overriding royalty payments may be granted to third parties in conjunction with the acquisition of drilling rights initially leased by others. As of December 31, 2008, we had leasehold rights to approximately 224,800 acres available for development.

Drilling Activities

The following table summarizes our development and exploratory drilling activity for the last three years. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of producing wells and wells capable of commercial production.

	Drilling Activity					
	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive (1)	349	303.8	327	258.9	216	129.8
Dry	8	8.0	11	9.7	6	4.6
	357	311.8	338	268.6	222	134.4

Total development						
Exploratory						
Productive (1)	7	7.0	1	0.2	8	2.8
Dry	10	9.6	7	4.5	1	0.5
Pending determination	5	5.0	3	3.0	-	-
Total exploratory	22	21.6	11	7.7	9	3.3
Total Drilling Activity	379	333.4	349	276.3	231	137.7

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(1) As of December 31, 2008, 94 of the 356 productive wells were awaiting gas pipeline connection, of which 38 were connected and turned in line by February 13, 2009.

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The following table sets forth the wells we drilled by operating area during the periods indicated.

	2008		2007		2006	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	63	63.0	8	8.0	-	-
Michigan Basin	2	1.6	3	3.0	1	1.0
Rocky Mountain Region	311	265.8	337	264.3	230	136.7
Fort Worth Basin	3	3.0	1	1.0	-	-
Total	379	333.4	349	276.3	231	137.7

We plan to drill approximately 166 gross wells, excluding exploratory wells, in 2009: 12 in the Appalachian Basin and 154 in the Rocky Mountain Region.

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, material and services we use in the development process are acquired 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.

Financing of Company Drilling and Development Activities

We conduct development drilling activities for our own account and act as operator for other oil and gas owners. When conducting activities for our own account, we have historically funded our operations through our cash flows from operations, capital provided from our long term credit facility and, in 2008, from our senior notes issuance. In the future, we expect to continue to use these same sources, but may also use other sources of funding, including, but not limited to, asset sales, volumetric production payments, debt securities, convertible debt securities and equity offerings.

Drilling and Development Activities Conducted for Company Sponsored Partnerships

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

When developing wells for our partnerships or others, we enter into a development agreement with the 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. In our financial reporting, we report only our proportionate share of oil and gas reserves, production, oil and gas sales and costs associated with wells in which other investors participate.

In January 2008, we announced that we did not plan to sponsor new drilling partnerships in 2008 in order to focus our effort on continuing our growth through drilling and exploration. Currently, we have no plans to sponsor a partnership in 2009.

Purchases of Producing Properties

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

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Production, Sales, Prices and Lifting Costs

The following table sets forth information regarding our production volumes, oil and natural gas sales, average sales price received and average lifting cost incurred for the periods indicated.

	Year Ended December 31,		
	2008	2007	2006
Production (1)			
Oil (Bbls)	1,160,408	910,052	631,395
Natural gas (Mcf)	31,759,792	22,513,306	13,160,784
Natural gas equivalent (Mcfe) (2)	38,722,240	27,973,618	16,949,154
Oil and Gas Sales (in thousands)			
Oil sales	$ 104,168	$ 55,196	$ 37,460
Gas sales	221,734	119,991	77,729
Royalty litigation provision	(4,025)	-	-
Total oil and gas sales	$ 321,877	$ 175,187	$ 115,189
Realized Gain (Loss) on Derivatives, net (in thousands)			
Oil derivatives - realized loss	$ (3,145)	$ (177)	$ -
Natural gas derivatives - realized gain	12,632	7,350	1,895
Total realized gain on derivatives, net	$ 9,487	$ 7,173	$ 1,895
Average Sales Price			
Oil (per Bbl) (3)	$ 89.77	$ 60.65	$ 59.33
Natural gas (per Mcf) (3)	$ 6.98	$ 5.33	$ 5.91
Natural gas equivalent (per Mcfe)	$ 8.42	$ 6.26	$ 6.80
Average Sales Price (including realized gain (loss) on derivatives)			
Oil (per Bbl)	$ 87.06	$ 60.46	$ 59.33
Natural gas (per Mcf)	$ 7.38	$ 5.66	$ 6.05
Natural gas equivalent (per Mcfe)	$ 8.66	$ 6.52	$ 6.91
Average Production Cost (Lifting Cost) per Mcfe (4)	$ 1.07	$ 0.90	$ 0.76

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

(2) A ratio of energy content of natural gas and oil (six Mcf of natural gas equals one Bbl of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.

(3) We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility of our natural gas and oil sales. This amount excludes realized and unrealized gains and losses on commodity based derivative instruments.

(4) Production costs represent oil and natural gas operating expenses which exclude production taxes.

Oil and Natural Gas Reserves

All of our natural gas and oil reserves are located in the U.S. We utilized the services of independent petroleum engineers to estimate our oil and gas reserves. For the years ended December 31, 2008 and 2007, our reserve estimates for the Appalachian and Michigan Basins are based on reserve reports prepared by Wright & Company and for the Rocky Mountain Region, reserve estimates are based on reserve reports prepared by Ryder Scott Company, L.P. For the year ended December 31, 2006, our reserve estimates for the Appalachian and Michigan Basins and NECO Area were based on reserve reports prepared by Wright & Company and our reserve estimates for the Rocky Mountain Region, with the exception of the NECO properties, were based on reserve reports prepared by Ryder Scott. The independent engineers' estimates are made using available geological and reservoir data as well as production performance data. The estimates are prepared with respect to reserve categorization, using the definitions for proved reserves set forth in Regulation S-X, Rule 4-10(a) and subsequent SEC staff interpretations and guidance. When preparing our reserve estimates, the independent engineers did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and natural gas production, well test data, historical costs of operations and developments, product prices, or any agreements relating to current and future operations of properties and sales of production. Our independent reserve estimates are reviewed and approved by our internal engineering staff and management.

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The tables below set forth information regarding our estimated proved reserves. Reserves cannot be measured exactly, because reserve estimates involve subjective judgments. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. Neither the present value of estimated future net cash flows nor the standardized measure is intended to represent the current market value of the estimated oil and natural gas reserves we own.

	Proved Reserves as of December 31,		
	2008	2007	2006
Oil (MBbl)	15,037	15,338	7,272
Natural gas (MMcf)	662,857	593,563	279,078
Total proved reserves (MMcfe)	753,079	685,591	322,710
Proved developed reserves (MMcfe)	329,669	317,884	165,690
Estimated future net cash flows (in thousands) (1)	$ 1,056,890	$ 1,847,485	$ 525,454
Standardized measure (in thousands) (1)(2)	$ 356,805	$ 753,071	$ 215,662

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(1) Estimated future net cash flow represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production costs, future development costs and income tax expense, using prices and costs in effect at December 31for each respective year. For the weighted average wellhead prices used in our reserve reports, see Note 18, “Supplemental Oil and Gas Information,” of our consolidated financial statements included in this report. These prices should not be interpreted as a prediction of future prices, nor do they reflect the value of our commodity hedges in place at December 31for each respective year. The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses and debt service, or to depreciation, depletion and amortization.

(2) The standardized measure of discounted future net cash flow is calculated in accordance with Statement of Financial Accounting Standards (“SFAS”) No. 69, which requires the future cash flows to be discounted. The discount rate used was 10%. Additional information on this measure, including a description of changes in this measure from year to year, is presented in Note 18, “Supplemental Oil and Gas Information,” of our consolidated financial statements included in this report.

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	Proved Reserves as of December 31, 2008			
	Oil (MBbl)	Gas (MMcf)	Gas Equivalent (MMcfe)	Percent
Proved developed				
Appalachian Basin	29	73,447	73,621	22%
Michigan Basin	40	19,784	20,024	6%
Rocky Mountain Region				
Wattenberg	5,079	50,005	80,479	25%
Grand Valley	173	111,310	112,348	34%
NECO	-	42,042	42,042	13%
North Dakota	105	114	744	0%
Wyoming	8	-	48	0%
Total Rocky Mountain Region	5,365	203,471	235,661	72%
Fort Worth Basin	4	339	363	0%
Total proved developed	5,438	297,041	329,669	100%
Proved undeveloped				
Appalachian	-	39,380	39,380	9%
Rocky Mountain Region				
Wattenberg	9,340	62,284	118,324	28%
Grand Valley	259	258,824	260,378	62%
NECO	-	5,328	5,328	1%
Total Rocky Mountain Region	9,599	326,436	384,030	91%
Total proved undeveloped	9,599	365,816	423,410	100%
Proved reserves				
Appalachian	29	112,827	113,001	15%
Michigan	40	19,784	20,024	3%
Rocky Mountain Region				
Wattenberg	14,419	112,289	198,803	27%
Grand Valley	432	370,134	372,726	49%
NECO	-	47,370	47,370	6%
North Dakota	105	114	744	0%
Wyoming	8	-	48	0%
Total Rocky Mountain Region	14,964	529,907	619,691	82%
Fort Worth Basin	4	339	363	0%
Total proved reserves	15,037	662,857	753,079	100%

Acreage

The following table sets forth by operating area leased acres as of December 31, 2008.

	Developed		Undeveloped		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	117,800	113,000	22,500	19,400	140,300	132,400
Michigan Basin	16,800	14,800	10,000	8,400	26,800	23,200

Rocky Mountain Region						
Wattenberg	45,800	43,400	30,100	24,000	75,900	67,400
Grand Valley	2,700	2,700	5,200	5,200	7,900	7,900
NECO	23,200	19,300	118,400	93,200	141,600	112,500
North Dakota	8,300	4,800	66,800	46,300	75,100	51,100
Wyoming	300	100	19,200	19,200	19,500	19,300
Total Rocky Mountain Region	80,300	70,300	239,700	187,900	320,000	258,200
Fort Worth Basin	400	400	12,100	9,100	12,500	9,500
Total Acreage	215,300	198,500	284,300	224,800	499,600	423,300

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Title to Properties

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the oil and natural gas industry. As is customary in the industry, a preliminary title examination is conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and curative work is performed with respect to discovered defects which we deem to be significant. Title examinations have been performed with respect to substantially all of our producing properties. Two properties in our Grand Valley Field represent 49% of our total proved reserves.

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

Natural Gas Sales

We generally sell the natural gas that we produce under contracts with indexed monthly pricing provisions. Virtually all of our contracts include provisions wherein prices change monthly with changes in the market, for which certain adjustments may be made based on whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions, so that the price of the natural gas fluctuates to remain competitive with other available natural gas supplies. As a result, our revenues from the sale of natural gas 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 also enter into financial derivatives such as puts, collars and swaps in order to reduce the impact of possible price instability regarding the physical sales market. See Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation: Results of Operations - Oil and Gas Price Risk Management, Net, Oil and Gas Derivative Activities and Note 3, Derivative Financial Instruments, to our consolidated financial statements included in this report.

We sell our natural gas to other gas marketers, utilities, industrial end-users and other wholesale gas purchasers. During 2008, the natural gas we produced was sold at prices ranging from $2.77 to $13.85 per Mcf, depending upon well location, the date of the sales contract and other factors. Our weighted net average price of natural gas sold in 2008 was $6.98 per Mcf.

In general, we have been and expect to continue to be able to produce and sell natural gas from our wells without significant curtailment and at competitive prices. We do experience limited curtailments from time to time due to pipeline maintenance and operating issues. For instance, we experienced an approximate 10% to 15% curtailment of production volumes, approximately 10,000 Mcf per day, in the Piceance Basin due to limited compression and pipeline capacity throughout most of the fourth quarter in 2008. This interruption, due to third party infrastructure, was corrected in early 2009. 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 our wells in North Dakota produce oil in addition to natural gas. As of December 31, 2008, oil represented 12% of our total equivalent reserves and accounted for approximately 32% of our oil and gas sales revenue for the year ended December 31, 2008.

We are currently able to sell all the oil that we can produce under existing sales contracts with petroleum refiners and marketers. We do not refine any of our oil production. Our crude oil production is sold to purchasers at or near our wells under both short and long-term purchase contracts with monthly pricing provisions. During 2008, oil we produced sold at prices ranging from $19.82 to $132.38 per Bbl, depending upon the location and quality of oil. Our weighted net average price per Bbl of oil sold in 2008 was $89.77.

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 for our own interest and that of our affiliated partnerships. 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.

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

RNG 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 in the Appalachian Basin from other producers and resells it to other marketers, utilities or end users. RNG's employees have extensive knowledge of natural gas markets in our areas of operations. Such knowledge assists us in maximizing our prices as we market natural gas from PDC-operated wells. The gas is marketed to other marketers, natural gas utilities, as well as industrial and commercial customers, either directly through our gathering system, or through transportation services provided by regulated interstate pipeline companies.

We have entered into various sales, transportation and processing agreements with unrelated third parties which we sell to or who transports our natural gas. The following table sets forth information about long-term firm sales, processing and transportation agreements for pipeline capacity, which require a demand charge whether volumes are delivered or not.

Type of Arrangement	Location	Average Annual Volume (MMbtu)	Expiration Date
Firm sales and processing	Grand Valley	23,218,287	May 2016
Firm transportation	NECO Area	1,825,000	December 2010
Firm transportation	NECO Area	1,825,000	December 2016
Firm transportation (1)	Appalachian Basin	12,230,785	December 2022

(1) Contract is a precedent agreement and becomes effective when the planned pipeline is placed in service, estimated at this time to be 2012. Contract is null and void if pipeline is not completed.

Commodity Risk Management Activities

We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility with regard to our oil and natural gas sales and marketing activities. These instruments consist of NYMEX-traded natural gas over-the-counter swaps, futures and option contracts for Appalachian and Michigan production, CIG and PEPL-based contracts for Colorado natural gas production and NYMEX-traded over-the-counter oil swaps and option contracts for Colorado oil production. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price stability for committed and anticipated oil and natural gas purchases and sales, generally forecasted to occur within the next two to three-year period, but no longer than five years beyond the derivative transaction date. Our policies prohibit the use of oil and natural gas futures, swaps 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 derivatives to reduce the risk and effect of natural gas price changes. RNG uses these financial derivatives to coordinate fixed purchases and sales. We use financial derivatives to establish “floors” and “ceilings” or “collars” on the possible range of the prices realized for the sale of natural gas and oil in addition to fixing prices by using swaps. RNG also enters into back-to-back fixed-price purchases and sales contracts with counterparties. These fixed physical contracts meet the SFAS No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, 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 statement of operations.

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

Well Operations

As of December 31, 2008, we had an interest in approximately 2,412 wells in the Rocky Mountain Region, 2,090 wells in the Appalachian Basin, and 210 wells in the Michigan Basin. On average, our interest ownership in these wells was approximately 69.2%.

We are paid a monthly operating fee for the portion of each well we operate that is owned by others, including our sponsored partnerships. The fee is competitive with rates charged by other operators in the area. The fee covers monthly operating and accounting costs, insurance and other recurring costs. If we purchase well interests belonging to investors in our sponsored partnerships, we then account for the purchased interests as being owned by us, which results in a decrease in well operations income.

Transportation and Gathering

We develop, own and operate gathering systems in some of our areas of operations. We also continue to construct new trunk lines as necessary to provide for the marketing of natural gas being developed from new areas and to enhance or maintain our existing systems. Pipelines and related facilities can represent a significant portion of the capital costs of developing wells, particularly in new areas located at a distance from existing pipelines. We consider these costs in our evaluation of our leasing, development and acquisition opportunities.

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

Governmental Regulation

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

Regulation of Oil and Natural Gas Exploration and Production

Our exploration and production business is subject to various federal, state and local laws and regulations on the taxation of oil and natural gas, the development, production and marketing of oil and natural gas and environmental and safety matters. Many laws and regulations require drilling permits and govern the spacing of wells, rates of production, water discharge, prevention of waste and other matters. Prior to commencing drilling activities for a well, we must procure permits and/or approvals for the various stages of the drilling process from the applicable state and local agencies in the state in which the area to be drilled is located. The permits and approvals include those for the drilling of wells. Additionally, other regulated matters include:

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

- the disposal of fluids.

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 oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. Where wells are to be drilled on state or federal leases, additional regulations and conditions may apply. The effect of these regulations may limit the amount of oil and natural gas we can produce from our wells and may limit the number of wells or the locations at which we can drill. Such laws and regulations may increase the costs of planning, designing, drilling, installing, operating and abandoning our oil and natural gas 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.

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Regulation of Sales and Transportation of Natural Gas

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

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

Each interstate natural gas pipeline company establishes its rates primarily through the FERC's 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. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen the increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in-gas, which could adversely affect cash flows from the affected area.

Additional proposals and proceedings that might affect the 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 tougher 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.

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We currently own or lease numerous properties that for many years have been used for the exploration and production of oil and natural gas. Although we believe that we have utilized good operating and waste disposal practices, and when necessary, appropriate remediation techniques, prior owners and operators of these properties may not have utilized similar practices and techniques, and hydrocarbons or other wastes may have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, RCRA and analogous state laws, as well as state laws governing the management of oil and natural gas 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 oil and natural gas wells, we may be liable pursuant to CERCLA and similar state laws.

Our operations may be subject to the Clean Air Act, or CAA, and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. The EPA and states have been developing regulations to implement these requirements. We may be required to incur certain capital expenditures in the next several years for air pollution control equipment in connection with maintaining or obtaining operating permits and approvals addressing other air emission-related issues. The State of Colorado has also indicated it intends to implement new air regulations in 2009, which affect the oil and gas industry, including our operations, related to air emissions.

The Federal Clean Water Act, or CWA, and analogous state laws impose strict controls against the discharge of pollutants, including spills and leaks of oil and other substances. The CWA also regulates storm water run-off from oil and gas facilities and requires a storm water discharge permit for certain activities. Spill prevention, control, and countermeasure requirements of the CWA require appropriate containment terms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture, or leak.

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

In December 2008, the State of Colorado's Oil and Gas Conservation Commission finalized new broad-based environmental regulations for the oil and natural gas industry. These regulations will increase our costs and may ultimately limit some drilling locations. Our expenses relating to preserving the environment have risen over the past few years and are expected to continue to rise in 2009 and beyond. Environmental regulations have had no materially adverse effect on our operations to date, but no assurance can be given that environmental regulations or interpretations of such regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on our business, financial condition or results of operations. See Note 8, Commitments and Contingencies – Litigation, Colorado Stormwater Permit, to our accompanying consolidated financial statements included in this report.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including, but not limited to, the risk of fire, explosions, blowouts, cratering, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of 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.

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

Competition

We believe that our exploration, drilling and production capabilities and the experience of our management and professional staff generally enable us to compete effectively. We encounter competition from numerous other oil and natural gas companies, drilling and income programs and partnerships in all areas of operations, including drilling and marketing oil and natural gas and obtaining desirable oil and natural gas leases on producing properties. Many of these competitors possess larger staffs and greater financial resources than we do, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. Our ability to explore for oil and natural gas prospects and to acquire additional properties in the future depends upon our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We also face intense competition in the marketing of natural gas from competitors including other producers as well as marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic oil and natural gas exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future. During 2008, our industry experienced continued strong demand for drilling services and supplies which resulted in increasing costs. In 2009, due to industry slowdown, we are experiencing overall reductions in our operating and drilling costs. Factors affecting competition in the oil and natural gas 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 oil and natural gas industry in each of the listed areas. Nevertheless, our business, financial condition and results of operations could be materially adversely affected by competition. We also compete with other oil and gas companies as well as companies in other industries for the capital we need to conduct our operations. Recently, turmoil in the capital markets has made financing more expensive and difficult to obtain. In the event that we do not have adequate capital to execute our business plan, we may be forced to curtail our drilling and acquisition activities.

Employees

As of December 31, 2008, we had 317 employees, including 205 in production, 8 in natural gas marketing, 28 in exploration and development, 49 in finance, accounting and data processing, and 27 in administration. Our engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and some pipeline systems. In addition, we retain subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites, with our employees supervising the activities of the subcontractors. In 2008, the total number of Company employees increased by 61.

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

ITEM 1A. RISK FACTORS

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

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Risks Related to the Global Economic Environment

The current global economic environment may increase the magnitude and the likelihood of the occurrence of the negative consequences discussed in many of the risks factors that follow.

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

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

During the second half of 2008 and to date, prices for oil and gas decreased over 70%. The well-publicized global financial market disruptions and the related economic environment may further decrease demand for oil and gas and therefore lower oil and gas prices. If there is such an additional reduction in demand, the continued production of gas may increase current oversupply and result in still lower gas prices. There is no certainty how long this low price environment will continue. We operate in a highly competitive industry, and certain competitors may have lower operating costs in such an environment. Furthermore, as a result of these disruptions in the financial markets, it is possible that in future years we would not be able to borrow sufficient funds to sustain or increase capital expenditures relative to 2008 expenditures, should we wish to make expenditures at those levels. Such market conditions may also make it more difficult or impossible for us to finance acquisitions, through either equity or debt; acquisitions have historically been a major source of growth for us. We may also have difficulty finding partners to develop new drilling prospects and to build the pipeline systems needed to transport our gas. Inability of third parties to finance and build additional pipelines out of the Rockies and elsewhere could cause significant negative pricing effects. Any of the above factors could adversely affect our operating results.

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

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

Our revenue, profitability and cash flow depend in large part upon the prices and demand for natural gas and oil. The markets for these commodities are very volatile, and even relatively modest drops in prices can significantly affect our financial results and impede our growth. Changes in natural gas and oil prices have a significant effect on our cash flow and on the value of our reserves, which can in turn reduce our borrowing base under our senior credit agreement. Prices for natural gas and oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control, including national and international economic and political factors and federal and state legislation. The prices from the fourth quarter of 2008 to date have been too low to economically justify many drilling operations, and it is uncertain how long such low pricing shall persist.

The prices of natural gas and oil are volatile, often fluctuating greatly. Lower natural gas and oil prices may not only reduce our revenues, but also may reduce the amount of natural gas and oil that we can produce economically. As a result, we may have to make substantial additional downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write-down operating assets to fair value, as a non-cash charge to earnings. We assess impairment of capitalized costs of proved natural gas and oil properties by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which management reasonably estimates such products may be sold. In 2008, we recorded an impairment charge of $7.5 million primarily related to our Texas Barnett Shale wells, and in 2006, we recorded an impairment charge of $1.5 million related to our Nesson field in North Dakota. There were no impairments during 2007. We may incur impairment charges in the future, which could have a material adverse effect on the results of our operations.

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

Our operations have been focused on the Rocky Mountain Region, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Because our operations are not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the affect of any regional events, including fluctuations in prices of natural gas and oil produced from the wells in the region, natural disasters, restrictive governmental regulations, transportation capacity constraints, curtailment of production or interruption of transportation, and any resulting delays or interruptions of production from existing or planned new wells.

During the last four months of 2008, natural gas prices in the Rocky Mountain Region fell disproportionately when compared to other markets, due in part to continuing constraints in transporting natural gas from producing properties in the region. Because of the concentration of our operations in the Rocky Mountain Region, and although, in late 2008 we entered into a significant multi-year basis hedge in order to minimize the price risk of our concentration in the Rocky Mountain Region, such price decreases are more likely to have a material adverse effect on our revenue, profitability and cash flow than those of our more geographically diverse competitors.

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

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

- the estimates of reserves;
- the economically recoverable quantities of natural gas and oil attributable to any particular group of properties;
- future depreciation, depletion and amortization rates and amounts;
- impairments in the value of our assets;
- the classifications of reserves based on risk of recovery;
- estimates of the future net cash flows; and
- timing of our capital expenditures.

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

The present value of our estimated future net cash flows from proved reserves is not necessarily the same as the current market value of our estimated natural gas and oil reserves (the SEC requires the use of year end prices). The estimated discounted future net cash flows from proved reserves are based on selling prices in effect on the day of estimate (year end). However, factors such as actual prices we receive for natural gas and oil and hedging instruments, the amount and timing of actual production, amount and timing of future development costs, supply of and demand for natural gas and oil, and changes in governmental regulations or taxation also affect our actual future net cash flows from our natural gas and oil properties.

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

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Unless natural gas and oil reserves are replaced as they are produced, our reserves and production will decline, which would adversely affect our future business, financial condition and results of operations.

Producing natural gas and oil reservoirs generally is characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we estimated and the rate can change due to other circumstances. Thus, our future natural gas and oil reserves and production and, therefore, our cash flow and income, are highly dependent on efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, discover or acquire additional reserves to replace our current and future production at acceptable costs. As a result, our future operations, financial condition and results of operations would be adversely affected.

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

Acquisitions of producing properties and undeveloped properties have been an important part of our historical growth. We expect acquisitions will also contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include recoverable reserves, development potential, future natural gas and oil prices, operating costs and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform engineering, geological and geophysical reviews of the acquired properties, which we believe is generally consistent with industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise. In some cases, our review prior to signing a definitive purchase agreement may be even more limited.

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

Additionally, significant acquisitions can change the nature of our operations depending upon the character of the acquired properties, which may have substantially different operating and geological characteristics or be in different geographic locations than our existing properties. For example, in the Castle acquisition, we acquired interests in wells which we will need to operate together with other partners, we acquired pipelines that we will need to operate and expect we will need to commit to drilling in the acquired areas to achieve the expected benefits. Consequently, we may not be able to efficiently realize the assumed or expected economic benefits of properties that we acquire, if at all.

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

A prospect is a property on which our geologists have identified what they believe, based on available information, to be indications of natural gas or oil bearing rocks. However, our geologists cannot know conclusively prior to drilling and testing whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in sufficient quantities to repay drilling or completion costs and generate a profit given the available data and technology. If a well is determined to be dry or uneconomic, which can occur even though it contains some oil or natural gas, it is classified as a dry hole and must be plugged and abandoned in accordance with applicable regulations. This generally results in the loss of the entire cost of drilling and completion to that point, the cost of plugging, and lease costs associated with the prospect. Even wells that are completed and placed into production may not produce sufficient natural gas and oil to be profitable. If we drill a dry hole or unprofitable well on current and future prospects, the profitability of our operations will decline and our value will likely be reduced. In sum, the cost of drilling, completing and operating any well is often uncertain and new wells may not be productive. Our recent uneconomic drilling in the Texas Barnett Shale illustrates this risk.

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

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

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

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

• unusual or unexpected geological formations;
• pressures;
• fires;
• blowouts;
• loss of drilling fluid circulation;
• title problems;
• facility or equipment malfunctions;
• unexpected operational events;
• shortages or delivery delays of equipment and services;
• compliance with environmental and other governmental requirements; and
• adverse weather conditions.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and regulatory penalties. We maintain insurance against various losses and liabilities arising from operations; however, insurance against all operational risks is not available. Additionally, our management may elect not to obtain insurance if the cost of available insurance is excessive relative to the perceived risks presented. Thus, losses could occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business activities, financial condition and results of operations.

Our oil and gas well drilling operations segment has historically received most of its revenue from the partnerships we sponsor, and a reduction or loss of that business could reduce or eliminate the revenue, profit and cash flow associated with those activities.

Our oil and gas well drilling operations segment has, prior to 2008, received most of its revenue from the partnerships we sponsor. We sponsor oil and natural gas partnerships through a network of non-affiliated FINRA broker dealers. We did not offer a partnership in 2008 and do not anticipate offering a partnership in 2009. There can be no assurance that the network of brokers will be available or can be recreated if we wish to use partnerships to raise funds in future years. In that situation, our operations and profitability could be adversely affected.

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

We have conducted exploratory drilling and plan to continue exploratory drilling in 2009 in order to identify additional opportunities for future development. Under the “successful efforts” method of accounting that we use, the cost of unsuccessful exploratory wells must be charged to expense in the period when they are determined to be unsuccessful. In addition, lease costs for acreage condemned by the unsuccessful well must also be expensed. In contrast, unsuccessful development wells are capitalized as a part of the investment in the field where they are located. Because exploratory wells generally are more likely to be unsuccessful than development wells, we anticipate that some or all of our exploratory wells may not be productive. The costs of such unsuccessful exploratory wells could result in a significant reduction in our profitability in periods when the costs are required to be expensed and these increased costs could reduce our net income and have a negative effect on our profitability and ability to repay or refinance our indebtedness.

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Increasing finding and development costs may impair our profitability.

In order to continue to grow and maintain our profitability, we must annually add new reserves that exceed our yearly production at a finding and development cost that yields an acceptable operating margin and depreciation, depletion and amortization rate. Without cost effective exploration, development or acquisition activities, our production, reserves and profitability will decline over time. Given the relative maturity of most natural gas and oil basins in North America and the high level of activity in the industry, the cost of finding new reserves through exploration and development operations has been increasing. The acquisition market for natural gas and oil properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values climbed toward historic highs during 2007 and 2008 on a per unit basis, particularly in the Rocky Mountain Region, and these values may continue to increase in the future. This increase in finding and development costs results in higher depreciation, depletion and amortization rates. If the upward trend in finding and development costs continues, we will be exposed to an increased likelihood of a write-down in carrying value of our natural gas and oil properties in response to falling commodity prices and reduced profitability of our operations.

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

The natural gas and oil industry is capital intensive. We expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas and oil reserves. To date, we have financed capital expenditures primarily with bank borrowings, cash generated by operations and our 2008 public note issuance. We intend to finance our future capital expenditures with cash flow from operations and our existing and planned financing arrangements. Our cash flow from operations and access to capital is subject to a number of variables, including:

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

If our revenues or the borrowing base under our credit facility decreases as a result of lower natural gas and oil prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

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

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

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

Seasonal weather conditions and lease stipulations designed to protect various wildlife affect natural gas and oil operations in the Rocky Mountains. In certain areas, including parts of the Piceance Basin in Colorado, drilling and other natural gas and oil activities are restricted or prohibited by lease stipulations, or prevented by weather conditions, for up to six months out of the year. This limits our operations in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase operating and capital costs and therefore adversely affect our profitability.

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

We operate most of the wells in which we own an interest. However, there are some wells we do not operate because we participate through joint operating agreements under which we own partial interests in natural gas and oil properties operated by other entities. If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator to adequately perform operations, or an operator's breach of the applicable agreements, could reduce production and revenues and affect our profitability. The success and timing of drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise (including safety and environmental compliance) and financial resources, inclusion of other participants in drilling wells, and use of technology.

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

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

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

We use derivatives for a portion of our natural gas and oil production from our own wells, our partnerships and for natural gas purchases and sales by our marketing subsidiary to achieve a more predictable cash flow, to reduce exposure to adverse fluctuations in the prices of natural gas and oil, and to allow our natural gas marketing company to offer pricing options to natural gas sellers and purchasers. These arrangements expose us to the risk of financial loss in some circumstances, including when purchases or sales are different than expected, the counter-party to the derivative contract defaults on its contract obligations, or when there is a change in the expected differential between the underlying price in the derivative agreement and actual prices that we receive.

In addition, derivative arrangements may limit the benefit from changes in the prices for natural gas and oil and may require the use of our resources to meet cash margin requirements. Since our derivatives do not currently qualify for use of hedge accounting, changes in the fair value of derivatives are recorded in our income statements, and our net income is subject to greater volatility than if our derivative instruments qualified for hedge accounting. For instance, if oil and gas prices rise significantly, it could result in significant non-cash charges each quarter, which could have a material negative effect on our net income.

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

Substantially all of our accounts receivable result from natural gas and oil sales or joint interest billings to a small number of third parties in the energy industry. This concentration of customers and joint interest owners may affect our overall credit risk in that these entities may be similarly affected by changes in economic and other conditions. In addition, our natural gas and oil derivatives as well as the derivatives used by our marketing subsidiary expose us to credit risk in the event of nonperformance by counterparties.

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

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

Our insurance coverage may not be sufficient to cover some liabilities or losses that we may incur.

The occurrence of a significant accident or other event not fully covered by insurance could have a material adverse effect on our operations and financial condition. Insurance does not protect us against all operational risks. We do not carry business interruption insurance at levels that would provide enough funds for us to continue operating without access to other funds. For some risks, such as drilling blow-out insurance, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks that we are subject to are generally not fully insurable.

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

The natural gas and oil industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement those new technologies at substantial cost. In addition, other natural gas and oil companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we were unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

Competition in the natural gas and oil industry is intense, which may adversely affect our ability to succeed.

The natural gas and oil industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce natural gas and oil, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas and oil properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than we can. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas and oil market prices. Larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which can adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because many companies in our industry have greater financial and human resources, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas and oil properties. These factors could adversely affect the success of our operations and our profitability.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of doing business.

Our exploration, development, production and marketing operations are regulated extensively at the federal, state and local levels. Environmental and other governmental laws and regulations have increased the costs to plan, design, drill, install, operate and abandon natural gas and oil wells. Under these laws and regulations, we could also be liable for personal injuries, property damage and other damages. Failure to comply with these laws and regulations may result in the suspension or termination of operations and subject us to administrative, civil and criminal penalties. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed, with some success, certain drilling projects.

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

Illustrative of these risks are regulations recently enacted by the State of Colorado which focus on the oil and gas industry. These multi-faceted proposed regulations significantly enhance requirements regarding oil and gas permitting, environmental requirements, and wildlife protection. Permitting delays and increased costs could result from these final regulations.

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

In recent years, litigation has commenced against us and several other companies in our industry regarding royalty practices and payments in jurisdictions where we conduct business. For more information on the suits that currently relate to us, see Item 3, Legal Proceedings. We intend to defend ourselves vigorously in these cases. Even if the ultimate outcome of this litigation resulted in our dismissal, defense costs could be significant. These costs would be reflected in terms of dollar outlay as well as the amount of time, attention and other resources that our management would have to appropriate to the defense. Although we cannot predict an eventual outcome of this litigation, a judgment in favor of a plaintiff could have a material adverse effect on our financial condition.

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

Our management assessed the effectiveness of our internal control over financial reporting as of December 31, 2008, and pursuant to this assessment, concluded that we did maintain effective internal control over financial reporting as of December 31, 2008. However, for each of the years in the three-year period ended December 31, 2007, management's assessment of the effectiveness of our internal control over financial reporting identified several material weaknesses as disclosed in our Annual Reports on Form 10-K for each of the years in the three-year period then ended and filed with the SEC on March 20, 2008, May 23, 2007, and May 31, 2006, respectively. The existence of a material weakness means there is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

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

Risks Associated with Our Indebtedness

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

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

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

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

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

• incur additional debt;
• make certain investments or pay dividends or distributions on our capital stock, or purchase, redeem or retire capital stock;
• sell assets, including capital stock of our restricted subsidiaries;
• restrict dividends or other payments by restricted subsidiaries;
• create liens;
• enter into transactions with affiliates; and
• merge or consolidate with another company.

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

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

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

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

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

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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ITEM 2. PROPERTIES

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

Substantially all of our oil and natural gas properties have been mortgaged or pledged as security for our credit facility. See Note 6, Long Term Debt, to our accompanying consolidated financial statements included in this report.

Facilities

We own our 32,000 square feet corporate office building located in Bridgeport, West Virginia. We lease approximately 5,000 and 17,000 square feet of office space in two buildings near our current corporate office through March 2010 and November 2011, respectively. We lease 15,700 square feet of office space in downtown Denver, Colorado through March 2012, which effective March 1, 2009, will become our corporate headquarters.

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

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

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 8, Commitments and Contingencies – Litigation and Note 17, Subsequent Events, to our consolidated financial statements included in this report.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

PART II

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

Our authorized capital stock consists of 100,000,000 shares of common stock, par value $0.01 per share. Our common stock is traded on the NASDAQ Global Select Market under the ticker symbol PETD.

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The following table sets forth the range of high and low sales prices for our common stock as reported on the NASDAQ Global Select Market for the periods indicated below.

	High	Low
2008		
First Quarter	$ 73.92	$ 50.75
Second Quarter	79.09	66.37
Third Quarter	68.76	34.15
Fourth Quarter	44.75	11.50
2007		
First Quarter	$ 55.20	$ 40.53
Second Quarter	55.24	44.59
Third Quarter	51.13	35.73
Fourth Quarter	61.91	41.65

As of February 23, 2009, we had approximately 1,107 shareholders of record.

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

The following table presents information about our purchases of our common stock during the three months ended December 31, 2008.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 - 31, 2008	118	$ 20.71	-	-
November 1-30, 2008	351	15.74	-	-
December 1-31, 2008	827	24.88	-	-
Total fourth quarter purchases	1,296	22.02		

(1) Pursuant to our stock-based compensation plans, the 1,296 shares purchased during the quarter represent purchases from our employees for their payment of tax liabilities related to the vesting of securities.

On October 16, 2006, our Board of Directors approved a share purchase program authorizing us to purchase up to 10% of our then outstanding common stock (1,477,109 shares) through April 2008. There were 1,465,089 shares that were authorized but not yet purchased as of December 31, 2007. Total shares purchased in 2008 pursuant to the program were 64,263 common shares at a cost of $4.4 million ($67.97 average price paid per share), including 63,756 shares from our executive officers at a cost of $4.3 million ($67.98 price paid per share). Shares purchased from employees, excluding executive officers, were generally purchased at fair market value based on the closing price on the date of purchase and were primarily purchased to satisfy the statutory minimum tax withholding requirement for restricted stock that vested in 2008. Shares purchased from executive officers were primarily pursuant to a separation agreement with our former president and to satisfy the statutory minimum tax withholding requirements for shares vested in 2008. The authorization to purchase the remaining 1,400,826 shares effectively expired on April 30, 2008. All shares purchased in accordance with the program have been subsequently retired.

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SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over a five year period ended December 31, 2008, with the cumulative total returns for the same period for a Standard Industrial Code Index, or SIC, and the Standard and Poor's, or S&P, 500 Index. The SIC Code Index is a weighted composite of 158 crude petroleum and natural gas companies. The cumulative total shareholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2003, and in the S&P 500 Index and the SIC Code Index on the same date. The results shown in the graph below are not necessarily indicative of future performance.

	Year Ended December 31, 2003	2004	2005	2006	2007	2008
PETROLEUM DEVELOPMENT CORPORATION	$ 100	$ 163	$ 141	$ 182	$ 249	$ 102
SIC CODE INDEX	100	127	183	237	334	195
S&P 500 INDEX	100	111	116	135	142	90

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2008	2007	2006	2005	2004
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 321,877	$ 175,187	$ 115,189	$ 102,559	$ 69,492
Sales from natural gas marketing activities	140,263	103,624	131,325	121,104	94,627
Oil and gas well drilling operations (1)	7,615	12,154	17,917	99,963	94,076
Well operations and pipeline income	11,474	9,342	10,704	8,760	7,677
Oil and gas price risk management gain (loss), net (2)	127,838	2,756	9,147	(9,368)	(3,085)
Other	293	2,172	2,221	2,180	1,696
Total revenues	609,360	305,235	286,503	325,198	264,483
Costs and expenses:					
Oil and gas production and well operations costs	78,209	49,264	29,021	20,400	17,713
Cost of natural gas marketing activities	139,234	100,584	130,150	119,644	92,881
Cost of oil and gas well drilling operations (1)	2,213	2,508	12,617	88,185	77,696
Exploration expense	45,105	23,551	8,131	11,115	-
General and administrative expense	37,715	30,968	19,047	6,960	4,506
Depreciation, depletion and amortization	104,575	70,844	33,735	21,116	18,156
Total costs and expenses	407,051	277,719	232,701	267,420	210,952
Gain on sale of leaseholds (3)	-	33,291	328,000	7,669	-
Income from operations	202,309	60,807	381,802	65,447	53,531
Interest income	591	2,662	8,050	898	185
Interest expense	(28,132)	(9,279)	(2,443)	(217)	(238)
Income before income taxes	174,768	54,190	387,409	66,128	53,478
Provision for income taxes	61,459	20,981	149,637	24,676	20,250
Net income	$ 113,309	$ 33,209	$ 237,772	$ 41,452	$ 33,228
Basic earnings per common share	$ 7.69	$ 2.25	$ 15.18	$ 2.53	$ 2.05
Diluted earnings per share	$ 7.63	$ 2.24	$ 15.11	$ 2.52	$ 2.00

	As of December 31,				
	2008	2007	2006	2005	2004
Total assets	$ 1,402,704	$ 1,050,479	$ 884,287	$ 444,361	$ 329,453
Working capital (deficit)	$ 31,266	$ (50,212)	$ 29,180	$ (16,763)	$ 231

Long-term debt	$	394,867	$	235,000	$	117,000	$	24,000	$	21,000
Shareholders' equity	$	511,581	$	395,526	$	360,144	$	188,265	$	154,021

(1)