PETROLEUM DEVELOPMENT CORP
Form 10-K
March 20, 2008

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, 2007

or

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

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 and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of 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, or non-accelerated file. See definition of "accelerated filer and larger accelerated filer" in Rule 12b-2 of the Exchange Act:

Large accelerated filer ¨	Accelerated filer x
Non-accelerated filer ¨	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, 2007, was $679,172,437 (based on the then closing price of $47.48).

As of March 14, 2008, there were 14,851,234 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form is incorporated by reference to our definitive proxy statement to be filed pursuant to Regulation 14A for our 2008 Annual Meeting of Shareholders.

PETROLEUM DEVELOPMENT CORPORATION
2007 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 report refer to the registrant, Petroleum Development Corporation, together with our subsidiaries, proportionate share of our sponsored drilling partnerships and an entity in which we have a controlling interest.

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 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 petroleum natural resources;
- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability of capital to us;
- risks incident to the drilling and operation of natural gas and oil wells;
- future production and development costs;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States;
- the effect of natural gas and oil derivatives activities;
- 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, or 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 publicly any forward-looking statements in order to reflect any event or circumstance occurring after the date of this report or currently unknown facts or conditions or the occurrence of unanticipated events.

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 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, 2007, we owned interests in approximately 4,354 gross wells located in the Rocky Mountain Region and the Appalachian and Michigan Basins with 686 billion cubic feet equivalent, or Bcfe, of net proved reserves, of which 86.6% was natural gas and 13.4% was oil.

During 2007, our share of production was 28 Bcfe, averaging 76.6 MMcfe per day, a 65% increase over 46.4 MMcfe per day produced in 2006. We replaced our 2007 production with 391 Bcfe of new proved reserves, net of dispositions, for a reserve replacement rate of 1,397%. Reserve replacement through the drillbit was 256 Bcfe, or 914% of production, and reserve replacement through acquisitions was 135 Bcfe, or 483% of production. Proved reserves grew 112% during 2007, from 323 Bcfe to 686 Bcfe, of which 54% 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 and Communications Department, P.O. Box 26, Bridgeport, WV 26330, 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, Board Nomination Procedures and the Whistleblower and Qualified Legal Compliance Committee Hotline, is also available at our website.

Business Strategy

Our primary objective is to continue to grow our reserves, production, net income and cash flow. To achieve meaningful increases in these key 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 Burke County, North Dakota. We drilled 349 gross wells in 2007, compared to 231 gross wells in 2006. In addition, we seek to maximize the value of our existing wells through a program of well recompletions and refractures. During 2007, we recompleted and/or refractured a total of 181 wells compared to 43 in 2006.

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, 2007, we had leases or other development rights to approximately 200,000 acres, of which approximately 164,000 acres, or 82%, were in the Rocky Mountain Region. We plan to drill approximately 360 gross, 330 net, wells in 2008, excluding exploratory wells. We also plan to recomplete approximately 100 gross Wattenberg Field wells (Colorado) and 30 gross wells in the Appalachian Basin during 2008. To support future development activities we have conducted exploratory drilling in the past and will continue exploratory drilling plans in 2008. The goal of the exploration program is to develop several significant new areas for us to include in our future development drilling activity.

Strategically Acquire

Our acquisition efforts focus on producing properties that complement our existing operations and 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. Since December 2006, we completed three acquisitions of assets or companies in our core operating area of the Wattenberg Field in Colorado, in addition to the acquisition of assets in southwestern Pennsylvania which are in close proximity to our existing assets in the Appalachian Basin. See Note 2, Acquisitions, to our 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 northern Colorado and the NECO area. Additionally, we regularly review opportunities to further diversify into other regions where we can apply our operational expertise. We believe development drilling will remain the foundation of our drilling activities in the future because it is less risky than exploratory drilling and is likely to generate cash returns more quickly. However, we expect that future activities may include a somewhat higher level of exploratory drilling in light of the increasing cost of accessing high-quality development opportunities and our ability, through increased size and financial strength, to pursue exploratory activities of greater significance. Additionally, exploratory activities have 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 gas industry, we maintain a conservative financial approach and proactively employ strategies to reduce the effects of commodity price volatility. We have utilized asset sales to maximize cash for acquisitions, to reduce debt and preserve our financial flexibility. 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, or hedges, in order 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 estimated production for the future periods based only on proved developed producing production as defined in SEC reserve rules. As of March 3, 2008, we had oil and natural gas hedges in place covering 41% of our expected oil production and 62% of our expected natural gas production in 2008. Further, while our derivative instruments are utilized to hedge our oil and gas production, they do not qualify for use of hedge accounting under the terms of SFAS No. 133, resulting in the potential for significant earnings volatility. See Note 1, Summary of Significant Accounting Polices – Derivative Financial Instruments, to our consolidated financial statements included in this report.

Business Segments

We divide our operating activities into four segments:

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

See Note 17, Business Segments, to our consolidated financial statements.

Oil and Gas Sales

Our oil and gas sales segment is our fastest growing business segment and reflects revenues and expenses from production and sale of natural gas and oil. We have interests in approximately 4,354 wells ranging from a few percent to 100%. During 2007, approximately 11% of our oil and gas sales revenue was generated by the Appalachian Basin, 6% by the Michigan Basin and 83% by Rocky Mountain Region. As of the end of 2007, our total proved reserves were located as follows: Appalachian Basin 15%, Michigan 4% and Rocky Mountain Region 81%. The majority of our undeveloped acreage is in the Rocky Mountain Region, where we focused our 2007 drilling activities. This segment represents approximately 78% of our income before income taxes for the year ended December 31, 2007.

Natural Gas Marketing

Our natural gas marketing segment is composed 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 7% of our income before income taxes for the year ended December 31, 2007.

Drilling and Development

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. In the future, we plan to evaluate the conduct of our drilling and development operations based on a comparison of the capital costs and risks associated with available financing alternatives. Beginning with our third 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.

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Our drilling and development segment represented approximately 18% of our income before income taxes for the year ended December 31, 2007. In January 2008, we announced that we do not plan to sponsor new drilling partnerships in 2008 in order to focus our effort on maximizing the value of the existing partnerships and our continuing growth through drilling and exploration. However, a portion of the funds available for drilling from the 2007 partnership were advanced and unexpended at the end of 2007, and they will be used to drill wells and the associated income will be recognized in 2008. With our plans not to sponsor a drilling partnership in 2008, we anticipate that its contribution to operating income to decline significantly in 2008.

Well Operations and Pipeline Income

We operate approximately 99% 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 a competitive fee for operating the well. Our well operations and pipeline income segment represented approximately 6% of our income before income taxes for the year ended December 31, 2007.

Areas of Operations

We focus our exploration, development and acquisition efforts in four geographic regions:

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

During 2007, we generated approximately 84.1% of our production from Rocky Mountain Region wells, 9.8% of our production from Appalachian Basin wells, 6.1% of our production from Michigan Basin wells. Production operations have not commenced in the Fort Worth Basin. The majority of our undeveloped acreage is in the Rocky Mountain Region and our current drilling plans continue to be focused in that area.

Rocky Mountain Region. In 1999, we began operations in the Rocky Mountain Region, which includes our Colorado and North Dakota operations. The region is further divided into four operating areas; (1) Grand Valley Field, (2) Wattenberg Field, (3) NECO area and (4) North Dakota area. The Rocky Mountain Region includes approximately 310,000 gross acres of leasehold and approximately 2,117 oil and natural gas wells in which we own an interest (approximately 99% are operated by us). 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 225 gross, 102.9 net, natural gas wells. Our leasehold position encompasses approximately 7,800 gross acres with approximately 3,900 net undeveloped acres remaining for development as of December 31, 2007. We drilled 53 gross, 41.7 net, wells in the area in 2007 and produced approximately 8.2 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 1,242 gross, 747.6 net, oil and natural gas wells. Our leasehold position encompasses approximately 65,000 gross acres with approximately 13,100 net undeveloped acres remaining for development as of December 31, 2007. We drilled 158 gross, 106.1 net, wells in the area in 2007 and produced approximately 11.1 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, includes the refrac of Codell and Niobrara reservoirs in existing wellbores whereby the Codell sandstone reservoir is re-stimulated or 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 586 gross, 383.3 net, natural gas wells. Our leasehold position encompasses approximately 104,500 gross acres with approximately 55,300 net undeveloped acres remaining for development as of December 31, 2007. We drilled 123 gross, 115 net, wells in the area in 2007 and produced approximately 3.6 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, 4.6 net, oil and natural gas wells. We divested the majority of our Bakken project acreage in late 2007 (see Note 16, Sale of Oil and Gas Properties, to our consolidated financial statements included in this report). Our remaining leasehold encompasses two project areas in Burke County and encompasses approximately 101,300 gross acres with approximately 60,000 net undeveloped acres remaining for development as of December 31, 2007. 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 22,746 gross and 18,607 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. We drilled one unsuccessful vertical exploratory well in 2007 and anticipate additional exploratory activity in 2008.

Appalachian Basin. We have conducted operations in the Appalachian Basin since our inception in 1969. We own an interest in approximately 2,027 gross, 1,501.6 net, oil and natural gas wells in West Virginia, Pennsylvania, and Tennessee. We drilled 8 gross/net wells in the area in 2007 and produced approximately 2.7 Bcfe net to our interests. The majority of the West Virginia leasehold is developed on approximately 40 acre spacing. We are currently evaluating the results of an infill drilling project on a limited portion of our developed leasehold. Wells located in this area are approximately 4,500 feet deep and target predominantly gas reserves in Devonian and Mississippian aged tight sandstone reservoirs. The majority of our 10,000 net undeveloped acres was acquired through our Castle acquisition in October 2007. Development wells in this area target similar Devonian aged sands as in West Virginia, at depths ranging from 3,000 to 4,500 feet.

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 209 gross, 145.6 net, oil and natural gas wells that produced 1.7 Bcfe net to our interest in 2007. Wells in the area range from 1,000 to 2,500 feet in depth and produce gas from the Antrim Shale. We drilled 3 gross and net wells in 2007.

Fort Worth Basin, Erath County, Texas. We have an interest in approximately 10,800 gross, 8,900 net acres, in northeastern Erath County. 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. As of December 31, 2007, we have drilled one exploratory Barnett well to total depth. The exploratory well was pending determination at December 31, 2007, see Note 4, Properties and Equipment - Suspended Well Costs. Completion operations have not commenced as we are awaiting the completion of a third party gas gathering infrastructure.

The table below sets forth our productive wells by operating area at December 31, 2007.

Productive Wells

	Gas		Oil	
Location	Gross	Net	Gross	Net
Appalachian Basin	1,988	1,486.2	39	15.4
Michigan Basin	202	142.9	7	2.7
Rocky Mountain Region				
Wattenberg	1,217	728.3	25	19.3
Grand Valley	225	102.9	-	-
NECO	586	383.3	-	-
North Dakota	4	1.3	9	3.3
Kansas	48	47.0	-	-
Wyoming	-	-	3	0.7
Total Rocky Mountain Region	2,080	1,262.8	37	23.3
Fort Worth Basin-Texas	1	1.0	-	-
Total Productive Wells	4,271	2,892.9	83	41.4

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Operations

Exploration and Development Activities

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

Prospect Generation

Our staff of professional geologists is responsible for identifying areas with potential for economic production of natural gas and oil. 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, 2007, we had leasehold rights to approximately 200,000 acres available for development.

Drilling Activities

The following table summarizes our development and exploratory drilling activity for the last five 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.

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Development						
Productive (1)	327.0	258.9	216.0	129.8	232.0	102.0
Dry	11.0	9.7	6.0	4.6	2.0	1.4
Total development	338.0	268.6	222.0	134.4	234.0	103.4
Exploratory						
Productive(1)	1.0	0.2	8.0	2.8	3.0	2.3
Dry	7.0	4.5	1.0	0.5	5.0	5.0
Pending determination	3.0	3.0	-	-	-	-
Total exploratory	11.0	7.7	9.0	3.3	8.0	7.3
Total Drilling Activity	349.0	276.3	231.0	137.7	242.0	110.7

(1) As of December 31, 2007, 128 of the 328 productive wells were awaiting gas pipeline connection, of which 39 were connected and turned in line by February 29, 2008.

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

	2007		2006		2005	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	8.0	8.0	-	-	-	-
Michigan Basin	3.0	3.0	1.0	1.0	-	-
Rocky Mountain Region	337.0	264.3	230.0	136.7	242.0	110.7
Fort Worth Basin	1.0	1.0	-	-	-	-
Total	349.0	276.3	231.0	137.7	242.0	110.7

We plan to drill approximately 360 gross wells, excluding exploratory wells, in 2008: 73 in the Appalachian Basin, 2 in the Michigan Basin and 285 in the Rocky Mountain Region.

Typically, we will act as driller-operator for these prospects, sometimes selling working interests in the wells to Company-sponsored partnerships and other entities that are interested in exploration or development of the prospects. We retain a working interest in each well we drill. Occasionally, we participate in wells as a working interest owner with another operator, typically when we own a minority interest in the property to be developed.

Most of the wells we have drilled have targeted developmental natural gas reserves at depths of less than 10,000 feet. Recently we began drilling to deeper targets in the Rocky Mountain Region, including several wells with depths of more than 12,000 feet and horizontal wells with a total drilled footage approaching 20,000 feet. As wells are drilled to greater depths or utilize more complicated and expensive drilling and completion methodologies, they must also develop greater reserves and production to offer attractive economics and reserves. However, the probability of encountering problems when drilling wells at greater depths or utilizing horizontal drilling is generally greater than when drilling a vertical well of lesser depth. Nevertheless, with increasing costs for, and declining availability of, proved developed drilling locations, we believe the additional risk associated with drilling these types of prospects is justified by the potential to generate additional proved locations and reserves at a significantly lower cost than would be required to purchase proved undeveloped locations.

We drilled eleven exploratory wells in 2007: one was determined to be productive, seven were determined to be dry, with the remaining three pending determination. Costs of $4.2 million related to the exploratory dry holes were expensed in 2007. We plan to conduct additional exploratory drilling activities in 2008. See sections entitled Financing of Company Drilling and Development Activities and Drilling and Development Activities Conducted for Company Sponsored Partnerships below for additional discussion regarding our drilling activities.

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 used cash flow from operations and capital provided from our long term credit facility to fund our share of operations. In the future, we may 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

In addition to wells and interests in wells that we drill for ourselves, we also act as operator for other oil and gas owners. Historically, these other owners have included individuals, corporations, partnerships formed by non-affiliated parties and other investors. We began sponsoring drilling partnerships in 1984, and have sponsored one or more every year since then. For many years, our drilling partners have consisted primarily of public and private partnerships we sponsored. We contribute a cash investment to purchase an interest in the drilling and development activities and serve as the managing general partner for each partnership; accordingly, we are subject to substantial cash commitments at the closing of each drilling partnership.

In January 2008, we announced that we do not plan to sponsor new drilling partnerships in 2008 in order to focus our effort on continuing our growth through drilling and exploration. However, a portion of the funds available for drilling from the 2007 partnership were advanced and unexpended at the end of 2007, and they will be used to drill wells and the associated income will be recognized in 2008.

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We sponsored partnerships in 2007 and 2006, each with $90 million in subscriptions, and in 2005, with $116 million in subscriptions. During 2007, we sponsored one drilling partnership to which we contributed $38.7 million and received a 37% working interest in the partnership. While funds were received by us pursuant to drilling contracts in the years indicated, we recognize revenues from drilling operations on the percentage of completion method as the wells were drilled, rather than when funds were received. Substantially all of our drilling and development funds were received from partnerships in which we serve as managing general partner. As wells produce for a number of years, we continue to serve as operator for a number of partnerships and 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.

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 of approximately 144 oil and gas wells and 8,160 acres of leaseholds in the Wattenberg Field from EXCO Resources. Also in January 2007, we purchased the outside partnership interests in 44 partnerships which 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. We estimated that the acquisition included approximately 47 Bcfe of reserves, or 31 Bcfe of proved reserves and 16 Bcfe of unproved reserves. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage.

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,					
		2007		2006		2005
Production (1)						
Oil (Bbls)		910,052		631,395		438,971
Natural gas (Mcf)		22,513,306		13,160,784		11,030,760
Natural gas equivalent (Mcfe) (2)		27,973,618		16,949,154		13,664,586
Oil and Gas Sales (in thousands)						
Oil sales	$	55,196	$	37,460	$	22,193
Gas sales		119,991		77,729		80,366
Total oil and gas sales	$	175,187	$	115,189	$	102,559
Realized Gain (Loss) on Derivatives, net (in thousands)						
Oil derivatives - realized (loss) gain	$	(177)	$	-	$	(1,288)

Natural gas derivatives - realized gain (loss)		7,350		1,895		(5,079)
Total realized gain (loss) on derivatives, net	$	7,173	$	1,895	$	(6,367)
Average Sales Price						
Oil (per Bbl) (3)	$	60.65	$	59.33	$	50.56
Natural gas (per Mcf) (3)	$	5.33	$	5.91	$	7.29
Natural gas equivalent (per Mcfe)	$	6.26	$	6.80	$	7.51
Average Sales Price (including realized gain (loss) on derivatives)						
Oil (per Bbl)	$	60.46	$	59.33	$	47.62
Natural gas (per Mcf)	$	5.66	$	6.05	$	6.83
Natural gas equivalent (per Mcfe)	$	6.52	$	6.91	$	7.04
Average Production Cost (Lifting Cost) per Mcfe (4)	$	1.34	$	1.23	$	1.19

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(1) Production as shown in the table is net and is 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 barrel of oil) was used to obtain a conversion factor to convert oil production into equivalent Mcf of natural gas.
(3) We utilize commodity based derivative instruments to manage a portion of our exposure to price volatility of our natural gas and oil sales. This amount excludes realized and unrealized gains and losses on commodity based derivative instruments.
(4) Production costs represent oil and gas operating expenses which include severance and ad valorem taxes as reflected in our financial statements. See Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Oil and Gas Production and Well Operations Costs."

Oil and Natural Gas Reserves

All of our natural gas and oil reserves are located in the United States. We utilized the services of two independent petroleum engineers for our 2007 and 2006 independent reserve reports. Wright & Company prepared the reserve reports for the Appalachian and Michigan Basins. Ryder Scott Company, L.P. prepared the reserve reports for the Rocky Mountain Region. Wright & Company prepared all of the reserve reports for us for 2005 with the exception of our 2005 North Dakota wells which were prepared by Ryder Scott Company, L.P. 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.

The tables below set forth information as of December 31, 2007, regarding our estimated proved reserves. Reserves cannot be measured exactly, because reserve estimates involve subjective judgment. 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.

	December 31, 2007		
	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)
Proved developed	8,927	314,123	367,685
Proved undeveloped	6,411	279,440	317,906
Total Proved	15,338	593,563	685,591

	Proved Developed	Proved Undeveloped	Total Proved
		(in millions)	
Estimated future net cash flows (1)	$ 1,203	$ 644	$ 1,847
Standardized measure (1)(2)	600	153	753

(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 31, 2007. The prices used in our reserve reports yield weighted average wellhead prices of $80.67 per barrel of oil and $6.77 per Mcf of natural gas. 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 31, 2007. 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 flows 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 is presented in Note 20, "Supplemental Oil and Gas Information," of our consolidated financial statements included in this report.

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	December 31, 2007			
	Oil (MBbl)	Gas (MMcf)	Gas Equivalent (MMcfe)	Percent
Proved developed				
Appalachian Basin	34	80,355	80,559	22%
Michigan Basin	58	23,979	24,327	7%
Rocky Mountain Region				
Wattenberg	8,473	67,227	118,065	32%
Grand Valley	107	91,326	91,968	25%
NECO	-	50,942	50,942	14%
North Dakota	250	294	1,794	0%
Wyoming	5	-	30	0%
Total Rocky Mountain Region	8,835	209,789	262,799	71%
Total proved developed	8,927	314,123	367,685	100%
Proved undeveloped				
Appalachian	-	22,115	22,115	7%
Rocky Mountain Region				
Wattenberg	6,210	40,729	77,989	24%
Grand Valley	201	200,998	202,204	64%
NECO	-	15,598	15,598	5%
Total Rocky Mountain Region	6,411	257,325	295,791	93%
Total proved undeveloped	6,411	279,440	317,906	100%
Proved reserves				
Appalachian	34	102,470	102,674	15%
Michigan	58	23,979	24,327	4%
Rocky Mountain Region				
Wattenberg	14,683	107,956	196,054	28%
Grand Valley	308	292,324	294,172	43%
NECO	-	66,540	66,540	10%
North Dakota	250	294	1,794	0%
Wyoming	5	-	30	0%
Total Rocky Mountain Region	15,246	467,114	558,590	81%
Total proved reserves	15,338	593,563	685,591	100%

Acreage

The following table sets forth by operating area leased acres as of December 31, 2007.

	Developed		Undeveloped		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin	84,240	84,240	10,000	10,000	94,240	94,240
Michigan Basin	8,240	8,240	440	440	8,680	8,680
New York	-	-	19,500	16,575	19,500	16,575
Rocky Mountain Region						
Wattenberg	50,860	47,440	14,093	13,143	64,953	60,583
Grand Valley	2,994	2,994	3,900	3,900	6,894	6,894

NECO	26,392	18,680	78,147	55,320	104,539	74,000
North Dakota	7,453	4,767	93,814	59,972	101,267	64,739
Wyoming	-	-	31,945	31,945	31,945	31,945
Total Rocky Mountain Region	87,699	73,881	221,899	164,280	309,598	238,161
Fort Worth Basin	-	-	10,804	8,868	10,804	8,868
Total Acreage	180,179	166,361	262,643	200,163	442,822	366,524

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 perfunctory 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 43% of our total proved reserves.

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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 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, or swaps in order to protect against possible price instability regarding the physical sales market.

We sell our natural gas to industrial end-users, utilities, other gas marketers, and other wholesale gas purchasers. During 2007, the natural gas we produce was sold at prices ranging from $1.68 to $18.56 per Mcf, depending upon well location, the date of the sales contract and other factors. Our weighted net average price of natural gas sold in 2007 was $5.33 per Mcf.

In general, we, together with our marketing subsidiary, RNG, have been and expect to continue to be able to produce and sell natural gas from our wells without significant curtailment and at competitive prices. We do experience limited curtailments from time to time due to pipeline maintenance and operating issues, and during October 2007, we chose to curtail some of our Piceance Basin production due to low prices. Open access transportation through the country's interstate pipeline system gives us access to a broad range of markets. Whenever feasible, we obtain access to multiple pipelines and markets from each of our gathering systems seeking the best available market for our natural gas at any point in time.

Oil Sales

The majority of our wells in the Wattenberg Field in Colorado and our wells in North Dakota produce oil in addition to natural gas. As of December 31, 2007, oil represented 13.4% of our total equivalent reserves and accounted for approximately 31.5% of our oil and gas sales revenue for the year ended December 31, 2007.

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 2007, oil we produced sold at prices ranging from $41.03 to $76.03 per barrel, depending upon the location and quality of oil. Our weighted net average price per barrel of oil sold in 2007 was $60.65.

Natural Gas Marketing

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

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

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

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

Commodity Risk Management Activities

We utilize commodity based derivative instruments to manage a portion of the exposure to price volatility stemming from our oil and natural gas sales and marketing activities. These instruments consist of over-the-counter swaps, NYMEX-traded natural gas futures and option contracts for Appalachian and Michigan production, Colorado Interstate Gas Index, or CIG, and Panhandle Eastern Pipeline-based contracts for Colorado natural gas production and NYMEX-traded oil futures and option contracts for Colorado oil production. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price protection for committed and anticipated oil and natural gas purchases and sales, generally forecasted to occur within the next two- to three-year period. 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 cash-settled derivatives to reduce the risk and effect of natural gas price changes. RNG uses these financial derivatives to coordinate fixed purchases and sales. We use financial derivatives to establish "floors" and "ceilings" or "collars" on the possible range of the prices realized for the sale of natural gas and oil. RNG also enters into back-to-back fixed-price purchases and sales contracts with counterparties. These fixed physical contracts meet the 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 income statement.

We are subject to price fluctuations for natural gas sold in the spot market and under market index contracts. We continue to evaluate the potential for reducing these risks by entering into derivative transactions. In addition, we may close out any portion of derivatives that may exist from time to time which may result in a realized gain or loss on that derivative transaction. We 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

At December 31, 2007, we had an interest in approximately 2,117 wells in the Rocky Mountain Region, 2,027 wells in the Appalachian Basin, and 209 wells in the Michigan Basin. Our ownership interest in these wells range up to 100% and as of December 31, 2007, on average, we had approximately 67.4% ownership interest in the wells we operated.

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. We may also receive additional compensation, at competitive rates, for special non-recurring activities, such as reworks and recompletions. If we purchase well interests belonging to investors in the partnerships, we then account for the purchased interests as being owned by us, which results in a decrease in well operations income. As of December 31, 2007, we operate approximately 99% of the wells in which we own a working interest.

Transportation

Natural gas wells are connected by pipelines to natural gas markets. Over the years, we have developed, 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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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 to between owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. In the western part of the United States, the federal and state governments own a large percentage of the land and the rights to develop oil and natural gas. Recently, we have increased our positions in these types of leases. Generally, government leases are subject to additional regulations and controls not commonly seen on private leases. We take the steps necessary to comply with applicable regulations, both on our own behalf and as part of the services we provide to our drilling partnerships. We believe that we are in compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. The following summary discussion of the regulation of the United States 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 taxation, the development, production and marketing of oil and 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. Also, 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.

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

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

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

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

The availability, terms and cost of transportation affect our natural gas sales. In the past, FERC has undertaken various initiatives to increase competition within the natural gas industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system was substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide transportation separate or "unbundled" from their sales service, and require that pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers. In many instances, the result of Order No. 636 and related initiatives has been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. Another effect of regulatory restructuring is greater access to transportation on interstate pipelines. In some cases, producers and marketers have benefited from this availability. However, competition among suppliers has greatly increased and traditional long-term producer-pipeline contracts are rare. Furthermore, gathering facilities of interstate pipelines are no longer regulated by FERC, thus allowing gatherers to charge higher gathering rates.

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

Environmental Regulations

Our operations are subject to numerous laws and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and 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.

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.

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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 later in 2008 which affect the oil and gas industry, including our operations, related to air emissions and wildlife.

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.

Our expenses relating to preserving the environment during 2007 were not significant in relation to operating costs and we expect no material change in 2008. Environmental regulations have had no materially adverse effect on our operations to date, but no assurance can be given that environmental regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on our business, financial condition or results of operations.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including the risk of fire, explosions, blowouts, cratering, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of toxic gas. The occurrence of any of these could result in substantial losses to us due to injury and loss of life, severe damage to and destruction of property, natural resources and equipment, pollution and other environmental damage, clean-up responsibilities, regulatory investigation and penalties and suspension of operations. Our pipeline, gathering and distribution operations are subject to the many hazards inherent in the natural gas industry. These hazards include damage to wells, pipelines and other related equipment, damage to property caused by hurricanes, floods, fires and other acts of God, inadvertent damage from construction equipment, leakage of natural gas and other hydrocarbons, fires and explosions and other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

Any significant problems related to our facilities could adversely affect our ability to conduct our operations. In accordance with customary industry practice, we maintain insurance against some, but not all, potential risks; however, there can be no assurance that such insurance will be adequate to cover any losses or exposure for liability. The occurrence of a significant event 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.

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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 2007, our industry experienced continued strong demand for drilling services and supplies. This is resulting in increasing costs, and in some cases the demand for supplies and services exceeds the available supplies. This can result in higher well costs and delays in the execution of planned drilling operations. Factors affecting competition in the 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 capital 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, 2007, we had 256 employees, including 164 in production, 7 in natural gas marketing, 26 in exploration and development, 37 in finance, accounting and data processing, and 22 in administration. Our engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and pipeline systems. In addition, we retain subcontractors to perform drilling, fracturing, logging, and pipeline construction functions at drilling sites, with our employees supervising the activities of the subcontractors. In 2007, the total number of Company employees increased by 67.

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

ITEM 1A. RISK FACTORS

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

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

Our "material weaknesses" in our internal control over financial reporting and resulting ineffective 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, 2007, and pursuant to this assessment, identified two material weaknesses in our internal control over financial reporting. The existence of any material weaknesses 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. The two material weaknesses relate to our failure to maintain effective controls over some of our key financial statement spreadsheets that support all significant balance sheet and income statement accounts and our failure to ensure proper accounting for derivative activities. For a more detailed discussion of our material weaknesses, see Item 8, Management's Report on Internal Control over Financial Reporting, and Item 9A, Controls and Procedures of this report. As a result of these material weaknesses, our management concluded that our disclosure controls and procedures were not effective as of December 31, 2007.

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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 would probably 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, our material weaknesses could lead to significant and negative changes to our financial condition and the value of our equity and debt securities.

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 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 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 2006, we recorded an impairment charge of $1.5 million related to our Nesson field in North Dakota. There were no impairments during 2007 or 2005. We may incur impairment charges in the future, which could have a material adverse effect on the results of our operations.

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

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

During the second half of 2007, natural gas prices in the Rocky Mountain Region have fallen disproportionately when compared to other markets, due in part to continuing constraints in transporting natural gas from producing properties in the region. Because of the concentration of our operations in the Rocky Mountain Region, such price decreases are more likely to have a material adverse effect on our revenue, profitability and cash flow than those of our more geographically diverse competitors.

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.

No one can measure underground accumulations of natural gas and oil in an exact way. 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:

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- 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;
- the classifications of reserves based on risk of recovery; and
- estimates of the future net cash flows.

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.

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 are 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. 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, as well as the acquisition of all shares of Unioil. 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.

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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.

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

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

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

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

- unusual or unexpected geological formations;
- pressures;
- fires;
- blowouts;
- loss of drilling fluid circulation;
- title problems;
- facility or equipment malfunctions;
- unexpected operational events;
- shortages or delivery delays of equipment and services;

- compliance with environmental and other governmental requirements; and
- adverse weather conditions.

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

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We may be forced to curtail our drilling operations, thereby reducing revenue and profits from new natural gas and oil wells and from our drilling and completion activities, due to increased drilling activity, particularly in the Rocky Mountain Region, which may create a shortage of drilling rigs, service providers, or materials.

With high natural gas and oil prices, many natural gas and oil companies have increased the drilling and completing of new wells and the reworking of old wells. At the same time there is a limited supply of drilling rigs, completion equipment and qualified personnel to provide the services necessary to drill, complete and rework new wells. We do not own any drilling rigs. The Rocky Mountain Region has seen a great increase in activity over the past few years. If the demand for these goods and services continues to increase, shortages may develop, which could result in increased prices for these goods and services or our inability to complete all of the drilling we have planned. Thus, we could be forced to drill less, and we could temporarily or permanently lose all or part of our drilling operations, negatively affecting our profits.

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 eliminated the revenue, profit and cash flow associated with those activities.

Our oil and gas well drilling operations segment has historically received most of its revenue from the partnerships we sponsor. We sponsor oil and natural gas partnerships through a network of non-affiliated NASD broker dealers. In January 2008, we announced that we would not be offering a partnership in 2008. 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 conducted exploratory drilling in 2006 and 2007 and plan to continue exploratory drilling in 2008 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.

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 2006 and 2007 on a per unit basis, particularly in the Rocky Mountain Region, and we believe these values may continue to increase in 2008. 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.

The natural gas and oil industry is capital intensive. We make and 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 and cash generated by operations. 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 are subject to a number of variables, including:

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

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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.

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.

Our credit facility has substantial restrictions and financial covenants and we may have difficulty obtaining additional credit, which could adversely affect our operations.

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.

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.

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.

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Our derivative activities could result in financial losses or reduced income.

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, we have recently increased our derivative use. The market prices for oil and natural gas, however, have continued to increase since such derivatives were entered; if such market pricing continues, it could result in significant non-cash charges each quarter, which could have a material negative affect 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, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks that we are subject to are generally not fully insurable.

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

The 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.

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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 and limit the quantity of natural gas and oil that can be produced and sold. 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 who can spread such additional costs over a greater number of wells and larger operating staff.

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.

Recent 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 two 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.

Information technology financial systems implementation problems could disrupt our internal business operations and adversely affect our business financial results or our ability to report our financial results.

We are currently in the process of implementing a new financial software system to enhance operating efficiencies and provide more effective management of our business operations. Our implementation is based on a phased approach, with the financial reporting system to be implemented in the first quarter of 2008. Implementations of financial systems and related software carry such risks as cost overruns, project delays and business interruptions, which could increase our expense, have an adverse effect on our business, our ability to report in an accurate and timely manner our financial position and our results of operations and cash flows.

Risks Associated with Our Indebtedness

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.

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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 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.

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 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.

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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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 5, Long Term Debt, to our consolidated financial statements included in this report.

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Facilities

We own our 32,000 square feet corporate office building located in Bridgeport, West Virginia. In February 2008, we entered into an agreement to lease approximately 17,000 square feet of office space in a building under construction near the corporate office and purchased an approximate 12 acre, undeveloped parcel of land adjacent to our existing corporate offices for potential future expansion of the corporate office facility. We maintain a lease for 13,000 square feet of administrative office space in downtown Denver, Colorado through May 2012.

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, 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 50,000,000 shares of common stock, par value $0.01 per share. There were 14,851,234 shares of common stock issued and outstanding as of March 14, 2008. Our common stock is traded on the NASDAQ Global Select Market under the ticker symbol PETD.

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
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
2006		
First Quarter	46.17	32.12
	45.62	32.51

Second Quarter		
Third Quarter	45.23	33.16
Fourth Quarter	47.44	36.54

As of March 14, 2008, we had approximately 1,242 shareholders of record.

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

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ISSUER PURCHASES OF EQUITY SECURITIES

Period	Total Number of Shares Purchased	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
Shares purchased prior to October 1, 2007, under the current repurchase program.	6,833	$ 50.63	6,833	1,470,276
Fourth quarter purchases:				
October 1 - 31, 2007	-	-	-	-
November 1-30, 2007	-	-	-	-
December 1-31, 2007	5,187	57.93	5,187	1,465,089
Total fourth quarter purchases	5,187		5,187	
Total shares purchased under the current program	12,020	53.78	12,020	1,465,089

On October 16, 2006, our Board of Directors approved a second 2006 share purchase program authorizing us to purchase up to 10% of our then outstanding common stock (1,477,109 shares) through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that we deem appropriate. Shares are generally purchased at fair market value based on the closing price on the date of purchase. Total shares purchased in 2007 pursuant to the program were 12,020 common shares at a cost of $0.6 million ($53.78 average price paid per share), including 5,187 shares from our executive officers at a cost of $0.3 million ($57.93 price paid per share). Shares purchased pursuant to the plan were primarily to satisfy the statutory minimum tax withholding requirement for restricted stock that vested in 2007. All shares were subsequently retired.

Pursuant to our senior notes indenture entered on February 8, 2008, any future purchases are limited, see Note 19, Subsequent Events, to our accompanying consolidated financial statements.

On February 25, 2008, pursuant to a separation agreement, we purchased 50,000 shares of our common stock from one of our executive officers at a cost of $3.4 million, or $67.92 per share. See Note 19, Subsequent Events, to our consolidated financial statements included in this report.

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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, 2007, 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 154 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, 2002, 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,					
	2002	2003	2004	2005	2006	2007
PETROLEUM DEVELOPMENT CORPORATION	$ 100.00	$ 447.17	$ 727.74	$ 629.06	$ 812.26	$ 1,115.66
SIC CODE INDEX	100.00	160.61	204.02	293.12	381.13	535.76
S&P 500 INDEX	100.00	128.68	142.69	149.70	173.34	182.87

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ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 175,187	$ 115,189	$ 102,559	$ 69,492	$ 48,394
Sales from natural gas marketing activities	103,624	131,325	121,104	94,627	73,132
Oil and gas well drilling operations (1)	12,154	17,917	99,963	94,076	57,510
Well operations and pipeline income	9,342	10,704	8,760	7,677	6,907
Oil and gas price risk management (loss) gain, net	2,756	9,147	(9,368)	(3,085)	(812)
Other	2,172	2,221	2,180	1,696	3,338
Total revenues	305,235	286,503	325,198	264,483	188,469
Costs and expenses:					
Oil and gas production and well operations costs	49,264	29,021	20,400	17,713	13,630
Cost of natural gas marketing activities	100,584	130,150	119,644	92,881	72,361
Cost of oil and gas well drilling operations (1)	2,508	12,617	88,185	77,696	46,946
Exploration expense	23,551	8,131	11,115	-	-
General and administrative expense	30,968	19,047	6,960	4,506	4,975
Depreciation, depletion and amortization	70,844	33,735	21,116	18,156	15,313
Total costs and expenses	277,719	232,701	267,420	210,952	153,225
Gain on sale of leaseholds (2)	33,291	328,000	7,669	-	-
Income from operations	60,807	381,802	65,447	53,531	35,244
Interest income	2,662	8,050	898	185	190
Interest expense	(9,279)	(2,443)	(217)	(238)	(816)
Income before income taxes and cumulative effect of change in accounting principle	54,190	387,409	66,128	53,478	34,618
Provision for income taxes	20,981	149,637	24,676	20,250	11,934
Income before cumulative effect of change in accounting principle	33,209	237,772	41,452	33,228	22,684
Cumulative effect of change in accounting principle (net of taxes of $1,392) (3)	-	-	-	-	(2,271)
Net income	$ 33,209	$ 237,772	$ 41,452	$ 33,228	$ 20,413
Basic earnings per common share	$ 2.25	$ 15.18	$ 2.53	$ 2.05	$ 1.30
Diluted earnings per share	$ 2.24	$ 15.11	$ 2.52	$ 2.00	$ 1.25

	December 31,				
	2007	2006	2005	2004	2003
Total assets	$ 1,050,479	$ 884,287	$ 444,361	$ 329,453	$ 294,004

Working capital (deficit)	$ (50,212)	$ 29,180	$ (16,763)	$ 231	$ 7,287
Long-term debt	$ 235,000	$ 117,000	$ 24,000	$ 21,000	$ 53,000
Shareholders' equity	$ 395,526	$ 360,144	$ 188,265	$ 154,021	$ 112,559

(1) In December 2005, we began entering into cost-plus drilling service arrangements, which are recorded on a net basis unlike our footage based arrangements which are recorded on a gross basis. See Note 1, "Summary of Significant Accounting Policies," to our consolidated financial statements included in this report.

(2) In July 2006, we sold a portion of our undeveloped leasehold located in Grand Valley Field, Garfield County, Colorado. See Note 16, "Sale of Oil and Gas Properties," to our consolidated financial statements included in this report.

(3) Represents the income effect of the adoption of SFAS No. 143, Accounting for Asset Retirement Obligations. See Note 7, "Asset Retirement Obligation," to our consolidated financial statements included in this report.

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

The following discussion and analysis, as well as other sections in this Form 10-K, should be read in conjunction with our accompanying consolidated financial statements and related notes to consolidated financial statements included in this report.

Year Ended December 31, 2007, Compared to December 31, 2006

Management Overview

Net Income

The following table presents net income and diluted earnings per share for the year ended December 31, 2007 and 2006.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Change Amount	Change Percent
	(dollars in thousands, except per share data)			
Net income	$ 33,209	$ 237,772	$ (204,563)	-86.0%
Diluted earnings per share	$ 2.24	$ 15.11	$ (12.87)	-85.2%

Net income for 2007, declined significantly due to last year's $328 million pretax gain associated with the July 2006 sale of a leasehold to an unrelated party (see Gain on Sale of Leaseholds below). In 2007, we had two sales of leaseholds, which totaled $33.3 million pretax. The positive driver of net income in 2007 was the 65% increase in production, which contributed to the $60 million increase in oil and gas sales despite lower average natural gas prices. The increase in oil and gas sales was offset by increases in depreciation, depletion and amortization, or DD&A, expense, production and well operations cost, exploration expense and general and administrative expense. Additionally, gains from oil and gas price risk management, net, decreased $6.4 million from a $9.1 million gain in 2006 to a $2.8 million gain in 2007, primarily due to increasing oil prices at the end of 2007.

Revenues

Revenues for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Change Amount	Change Percent
	(dollars in thousands)			
Revenues:				
Oil and gas sales	$ 175,187	$ 115,189	$ 59,998	52.1%
Sales from natural gas marketing activities	103,624	131,325	(27,701)	-21.1%
Oil and gas well drilling operations	12,154	17,917	(5,763)	-32.2%
Well operations and pipeline income	9,342	10,704	(1,362)	-12.7%
Oil and gas price risk management gain, net	2,756	9,147	(6,391)	-69.9%
Other	2,172	2,221	(49)	-2.2%
Total revenues	$ 305,235	$ 286,503	$ 18,732	6.5%

Total revenues for 2007 were up $18.7 million or 6.5% over 2006. The increase was primarily due to a 52.1 % increase in oil and gas sales largely offset by declines in natural gas marketing activities, oil and gas well drilling operations and oil and gas price risk management gain, net.

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Oil and natural gas sales increased $60 million as a result of the increase in production of 65% although natural gas prices declined an average of 10% per Mcf. Our natural gas marketing division enters into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. The decreases in both sales from natural gas marketing activities and oil and gas price risk management, net, are a result of a comparison of lower natural gas prices at December 31, 2006, compared with the higher fourth quarter and year-end 2007 pricing. Lower well operations and pipeline income is directly attributable to our January 2007 acquisition of the outstanding partnership interests in 44 of our sponsored drilling partnerships for which we no longer receive income for operating these wells and related pipelines.

Costs and Expenses

Costs and expenses for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Costs and expenses:				
Oil and gas production and well operations cost	$ 49,264	$ 29,021	$ 20,243	69.8%
Cost of natural gas marketing activities	100,584	130,150	(29,566)	-22.7%
Cost of oil and gas well drilling operations	2,508	12,617	(10,109)	-80.1%
Exploration expense	23,551	8,131	15,420	189.6%
General and administrative expense	30,968	19,047	11,921	62.6%
Depreciation, depletion and amortization	70,844	33,735	37,109	110.0%
Total costs and expenses	$ 277,719	$ 232,701	$ 45,018	19.4%

The increase in total costs and expenses for 2007 compared to 2006 was a reflection of our growth over the past year, which was funded primarily by the reinvestment of the proceeds from the 2006 sale of undeveloped leasehold of $353.6 million into productive operating properties. Due to the acquisitions and the significant number of new wells drilled for our own account and placed in service during 2007, we have substantially increased production, resulting in higher costs and expenses.

The increases in oil and gas production and well operations cost and DD&A expense for 2007 over 2006 reflects the growth we are currently experiencing through acquisitions and increased drilling. The larger number of new wells drilled and the increasing cost of well drilling, completion and equipping of new wells, along with the higher market cost of our 2007 property acquisitions, is reflected in the DD&A rate of our oil and gas properties, which increase from $1.86 per Mcfe in 2006 to $2.37 per Mcfe in 2007. The increase in exploration expense in 2007 was due to the liquidated damages from an exploration agreement and the subsequent lease abandonment, expense related to eight exploratory dry holes, including one that was pending determination at December 31, 2006, and increases in other exploratory costs. The decrease in natural gas marketing costs corresponds to the decline in sales from natural gas marketing activities as referenced above. While general and administrative expense increased $11.9 million from 2006 to 2007, general and administrative expense on a unit of production basis remained relatively unchanged.

See the following discussion of results of operations describing in more detail the components of revenues and expenses and, where significant, providing an analysis of changes year over year and the cause or underlying reason for such change.

Results of Operations

Revenues

Oil and Gas Sales

The table below sets forth revenues for oil and gas sales for the years ended December 31, 2007 and 2006, excluding the impact of commodity based derivative instruments, which are included in oil and gas price risk management gain, net in the statement of income.

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	Year Ended December 31, 2007	Year Ended December 31, 2006	Change Amount	Change Percent
	(dollars in thousands)			
Oil and gas sales	$ 175,187	$ 115,189	$ 59,998	52.1%

The increase in oil and gas sales in 2007 was primarily due to increased volumes of oil and natural gas of 65%, partially offset by lower average sales prices of natural gas. The increased volume of oil and natural gas contributed $75 million to oil and gas sales, while the decline in natural gas prices reduced oil and gas sales by $14 million in 2007 compared to 2006. The increase in natural gas and oil volumes was the result of our increased investment in oil and gas properties, primarily the fourth quarter 2006 and first quarter 2007 acquisitions and the significantly increase in the number of wells we drilled for our own account over the past year. The oil and gas sales generated during 2007 from the acquisitions made in 2007 and December 2006, and their subsequent development, were $45.8 million.

Oil and Natural Gas Production. Oil and natural gas production by area of operation along with average sales price (excluding derivative gains/losses) for the year is presented below.

	2007 Oil (Bbls)	2007 Natural Gas (Mcf)	2007 Natural Gas Equivalent (Mcfe)	2006 Oil (Bbls)	2006 Natural Gas (Mcf)	2006 Natural Gas Equivalent (Mcfe)	Change Oil (Bbls)	Change Natural Gas (Mcf)	Change Natural Gas Equivalent (Mcfe)
Production (Mcf)									
Appalachian Basin	5,490	2,711,300	2,744,240	1,837	1,451,729	1,462,751	199%	87%	88%
Michigan Basin	4,301	1,678,155	1,703,961	4,439	1,399,852	1,426,486	-3%	20%	19%
Rocky Mountain Region	900,261	18,123,851	23,525,417	625,119	10,309,203	14,059,917	44%	76%	67%
Total	910,052	22,513,306	27,973,618	631,395	13,160,784	16,949,154	44%	71%	65%

	2007 (in thousands, except average price)			2006 (in thousands, except average price)			Change		
Sales									
Appalachian Basin	$ 324	$ 18,952	$ 19,276	$ 110	$ 10,699	$ 10,809	194%	77%	78%
Michigan Basin	294	10,270	10,564	271	9,141	9,412	8%	12%	12%
Rocky Mountain Region	54,578	90,769	145,347	37,079	57,889	94,968	47%	57%	53%
Total	$ 55,196	$ 119,991	$ 175,187	$ 37,460	$ 77,729	$ 115,189	47%	54%	52%
Average Sales Price									
(Oil - per Bbl, Natural Gas - per Mcf)									
Appalachian Basin	$ 59.08	$ 6.99	$ 7.02	$ 60.14	$ 7.37	$ 7.39	-2%	-5%	-5%
Michigan Basin	68.31	6.12	6.20	61.07	6.53	6.60	12%	-6%	-6%
Rocky Mountain Region	60.62	5.01	6.18	59.31	5.62	6.75	2%	-11%	-9%
Total	$ 60.65	$ 5.33	$ 6.26	$ 59.33	$ 5.91	$ 6.80	2%	-10%	-8%

The production generated from the acquisitions made in 2007 and December 2006, and their subsequent development, was 6.5 Bcfe. This represents approximately 59% of the total 11.0 Bcfe increase in production in 2007 compared to 2006.

Late in the second quarter of 2007, we placed into service the upgraded Garden Gulch pipeline and compressor facility, which serves a majority of our wells in the Piceance Basin. This upgrade included two new natural gas compressors, with a third compressor added in the third quarter, and pipeline facility enhancements. The upgrade and enhancements have increased the capacity of the pipeline delivery system from 17,000 Mcf per day to 60,000 Mcf per day from the wells feeding this facility from the time of our start-up in late June 2007.

Oil and Natural Gas Pricing. Financial results depend upon many factors, particularly the price of natural gas and our ability to market our production effectively. Natural gas and oil prices have been among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas and oil prices also vary by region and locality, depending upon the distance to markets, and the supply and demand relationships in that region or locality. This can be especially true in the Rocky Mountain Region. The combination of increased drilling activity and the lack of local markets could result in a local market oversupply situation from time to time. Such a situation existed in the Rocky Mountain Region during 2007, with production exceeding the local market demand and pipeline capacity to non-local markets. The result, beginning in the second quarter of 2007 and continuing into the fourth quarter of 2007, had been a decrease in the price of Rocky Mountain natural gas compared to the NYMEX price and other markets as shown in the graph below. The expansion in January 2008 of the Rockies Express pipeline, or REX, is the primary reason for the narrowing of the NYMEX/CIG gap in December 2007 and forward. Once the third phase of the expansion of the Rockies Express is completed in 2009, the pipeline capacity is expected to increase by 64% to 1.8 Bcf/per day of natural gas from the region. Like most producers in the region, we rely on major interstate pipeline companies to construct these facilities to increase pipeline capacity, rendering the timing and availability of these facilities beyond our control.

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Rocky Mountain Region Pricing. Although our weighted average price for natural gas in 2007 was $5.33 per Mcf, the price we receive for a large portion of the natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which may include some gas sold at the Colorado Interstate Gas, or CIG, Index. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is New York Mercantile Exchange, or NYMEX, based. The natural gas price in the eastern regions, where 19.5% of our total natural gas production for the year was produced, was $6.67 per Mcf compared to our Rocky Mountain Region price per Mcf of $5.01. The Rocky Mountain Region contributed 80.5% of our natural gas for the year and is where we anticipate a majority of our future production increases will occur. During 2007, through our derivative activities, we realized a benefit from the floors put in place on our production in the Rocky Mountain Region. We received $7.2 million in proceeds (gross, excluding the cost of floors) from our derivative instruments during 2007 or $0.40 per Mcf, which helped to offset the lower prices we received for our Rocky Mountain Region natural gas. We report our activities from derivative transactions under the oil and gas price risk management, net line item in our accompanying consolidated statements of income.

The graph below identifies the actual NYMEX and CIG natural gas prices by month from January 2006 through February 2008 and the forward curve for natural gas prices through March 2009 as of February 15, 2008. The forecasted prices in the graph have been derived from the sources indicated and represent, in our opinion, a reasonable view of the possible movement of the CIG and NYMEX natural gas prices over the next thirteen months. However, because the prices given in the graph represent forecasts of future matters and are subject to future events which we cannot predict, we can give no assurance that these forecasted prices will be as they are presented in the graph. An investor should therefore not rely on these forecasted prices in making an investment decision regarding our stock.

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*Source: Derived from various sources including FutureSource, Inside FERC's Gas Market Report and ClearPort Trading.

While the above graph shows a large differential between recent NYMEX and CIG pricing, the gap began narrowing in November 2007 and has continued. As of February 15, 2008, the price differential between NYMEX and CIG for 2008 has narrowed to $(1.32) from $(3.38) average for the fourth quarter. Although 80.5% of our 2007 natural gas production came from the Rocky Mountain Region, the Rocky Mountain natural gas pricing is based upon other indices in addition to CIG.

The table below identifies the basis of our natural gas and oil pricing on a sales volume basis for the year ended December 31, 2007. It further outlines that 38% of our natural gas sales are derived from the CIG Index and other similarly priced Rocky Mountain pipelines. In 2007, we realized considerably higher prices associated with our non CIG volumes.

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Energy Market Exposure
as of December 31, 2007

Area	Pricing Basis	Commodity	Percent of Oil and Gas Sales
Grand Valley/Wattenberg	Rocky Mountain (CIG, et. al.)	Gas	38%
Colorado/North Dakota	NYMEX	Oil	16%
NECO/Grand Valley	Mid Continent (Panhandle Eastern)	Gas	29%
Appalachian	NYMEX	Gas	10%
Michigan	Mich-Con/NYMEX	Gas	4%
Wattenberg	Colorado Liquids	Gas	2%
Other	Other	Gas/Oil	1%
			100%

Sales from Natural Gas Marketing Activities

Revenues from natural gas marketing activities for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31, 2007	2006	Change Amount	Percent
	(dollars in thousands)			
Sales from natural gas marketing activities	$ 103,624	$ 131,325	$ (27,701)	-21.1%

The decrease in sales from natural gas marketing activities in 2007 was primarily due to a decrease in prices and a decrease in volumes sold, along with a $14 million decrease in unrealized gains on derivative transactions, from a $12.3 million gain in 2007 to a $1.7 million loss in 2007. In 2007, prices were 5% lower on average than in 2006, resulting in a $4.8 million decline in sales, and volumes sold decreased by 9%, resulting in an additional $8.8 million decline in sales. In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships. Since this acquisition, we no longer record oil and gas sales for the net 423 wells acquired. In total, our natural gas marketing segment's sales volumes increased by 4% in 2007; however, once the intercompany volumes are eliminated, the net remaining sales from our natural gas marketing segment declined.

Our natural gas marketing segment is composed of our wholly owned subsidiary, RNG. RNG is a natural gas marketing company that specializes in the purchase, aggregation and sale of natural gas production in our Eastern operating areas. RNG markets the natural gas we produce and also purchases natural gas in the Appalachian Basin from other producers, including our affiliated partnerships, and resells it to utilities, industrial and commercial customers as well as other marketers. RNG has established relationships with many of the natural gas producers in the Appalachian Basin and has gained significant expertise in the natural gas end-user market. RNG's sales to end-user customers utilize transportation services provided by regulated interstate pipeline companies. RNG's derivative activities are comprised of both physical and cash-settled derivatives. RNG offers fixed-price derivative contracts for the purchase or sale of physical gas. RNG also enters into cash-settled derivative positions with counterparties in order to offset those same physical positions. RNG does not take speculative positions on commodity prices.

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The following table sets forth RNG's derivative positions in effect as of December 31, 2007.

Riley Natural Gas
Open Derivative Positions
(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	588,950	$ 7.79	$ 4,586	$ (246)
Natural Gas	Cash Settled Futures/Swaps Sales	2,085,400	8.50	17,722	1,236
Natural Gas	Cash Settled Basis Swap Purchases	397,500	0.54	214	3
Natural Gas	Physical Purchases	2,085,400	8.51	17,748	(473)
Natural Gas	Physical Sales	518,951	8.50	4,409	129
					$ 649

Oil and Gas Well Drilling Operations

Revenues from drilling operations for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31, 2007	2006	Change Amount	Percent
	(dollars in thousands)			
Oil and gas well drilling operations	$ 12,154	$ 17,917	$ (5,763)	-32.2%

The decrease in oil and gas well drilling operations revenue was due to our change from footage-based drilling arrangements to cost-plus drilling arrangements, which are presented differently for accounting purposes. Beginning with the last sponsored partnership in 2005 (for which revenue generating activities began in 2006), our partnership wells have been drilled on a "cost-plus" basis, which means that we charge the partnerships for the actual cost of the wells plus an agreed upon mark-up above that cost. Prior to that partnership, we had conducted most of our third-party drilling activities on a footage basis, pursuant to which we drilled the wells for a fixed price per foot drilled with additional chargeable items as provided for in the drilling agreement. Our services provided under the cost-plus drilling arrangements are reported net of recovered costs and reflected as revenue in oil and gas well drilling operations, whereas the revenues under the footage-based arrangements were recorded gross of related expenses. For the year ended December 31, 2006, oil and gas well drilling operations included $5.4 million in revenues related to footage based arrangements.

Well Operations and Pipeline Income

Revenues from well operations and pipeline income for the years ended December 31, 2007 and 2006 are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Well operations and pipeline income	$ 9,342	$ 10,704	$ (1,362)	-12.7%

In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships. Having acquired 423 net wells pursuant to the acquisition, we no longer record income for operating these wells and related pipelines. This decrease in revenue was offset in part by an increase in the number of new wells drilled and placed in service and pipeline systems we operate for our sponsored drilling partnerships as well as third parties.

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Oil and Gas Price Risk Management, Net

Oil and gas price risk management, net for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Oil and gas price risk management gain, net	$ 2,756	$ 9,147	$ (6,391)	-69.9%

In 2007, we recorded realized gains of $7.2 million and unrealized losses of $4.4 million, resulting in a net $2.8 million gain for the year. In 2006, we incurred realized and unrealized gains of $1.9 million and $7.2 million, respectively, resulting in a $9.1 million gain. The significant decline in the CIG market during the fall of 2007 resulted in the substantial realized gains in 2007. When forward prices for oil and natural gas prices increase, as they did at December 31, 2007, and for the additional increases we are experiencing in 2008, our derivative portfolio, which includes floors and swaps, decreases in value, resulting in unrealized loss positions.

Oil and gas price risk management, net is comprised of realized and unrealized changes in the fair value of oil and natural gas derivatives related to our oil and natural gas production. Oil and gas price risk management, net does not include commodity based derivative transactions related to transactions from marketing activities, which are included in sales from and cost of natural gas marketing activities.

Oil and Natural Gas Derivative Activities. Because of the uncertainty surrounding natural gas and oil prices, we have used various derivative instruments to manage some of the effect of fluctuations in prices. Through December 2010, we have in place a series of floors and ceilings, or “collars”, on a portion of the natural gas and oil production. Under the arrangements, if the applicable index rises above the ceiling price, we pay the counterparty; however, if the index drops below the floor, the counterparty pays us. Through February 2011, we have fixed price swaps in place on a small portion of our natural gas production. During the three months ended December 31, 2007, our average monthly natural gas and oil volumes sold were 2.3 Bcf and 81,100 Bbls.

The following table sets forth our derivative positions in effect as of December 31, 2007, and includes positions entered into subsequently through March 3, 2008, on our share of production by area. The table does not include positions related to RNG or derivative contracts we entered into on behalf of our affiliated partnerships.

		Floors		Ceilings		Swaps (Fixed Prices)	
		Monthly Quantity Gas-MMbtu Oil-Bbls	Contract Price	Monthly Quantity MMbtu	Contract Price	Monthly Volume MMbtu/Bbls	Price
Month Set	Months Covered						
Colorado Interstate Gas (CIG) Based Hedges (Grand Valley Field, Piceance Basin)							
Dec-06	Jan 2008 – Mar 2008	247,700	$ 5.25	-	$ -	-	$ -
Jan-07	Jan 2008 – Mar 2008	247,700	5.25	247,700	9.80	-	-
Feb-08		-	-	-	-	488,900	7.05

	April 2008 – Oct 2008						
Jan-08	April 2008 – Oct 2008	-	-	-	-	410,700	6.54
Jan-08	Jan 2008 - Mar 2009	371,600	6.50	371,600	10.15	-	-
Feb-08	Jan 2008 - Mar 2009	221,650	7.00	221,650	9.70	-	-
Feb-08	Jan 2008 - Mar 2009	-	-	-	-	221,650	8.18
Jan-08	April 2009 - Oct 2009	371,600	5.75	371,600	8.75	-	-
Mar-08	April 2009 - Oct 2009	365,050	5.75	365,050	9.05	-	-
NYMEX Based Hedges - (Appalachian and Michigan Basins)							
Dec-06	Jan 2008 – Mar 2008	123,100	7.00	-	-	-	-
Jan-07	Jan 2008 – Mar 2008	123,100	7.00	123,100	13.70	-	-
Feb-08	April 2008 – Oct 2008	-	-	-	-	123,100	8.33
Feb-08	April 2008 – Oct 2008	-	-	-	-	123,100	8.58
Jan-08	Nov 2008 - Mar 2009	123,100	9.00	123,100	11.32	-	-
Feb-08	Nov 2008 - Mar 2009	72,400	8.40	72,400	13.05	-	-
Feb-08	Nov 2008 - Mar 2009	-	-	-	-	72,400	9.62
Jan-08	April 2009 - Oct 2009	123,100	6.75	123,100	12.45	-	-
Mar-08	April 2009 - Oct 2009	123,100	7.50	123,100	13.25	-	-
Feb-08	Mar 2008 - Feb 2011	-	-	-	-	90,000	8.62

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		Floors		Ceilings		Swaps (Fixed Prices)	
		Monthly Quantity Gas-MMbtu Oil-Bbls	Contract Price	Monthly Quantity MMbtu	Contract Price	Monthly Volume MMbtu/Bbls	Price
Month Set	Months Covered						
Panhandle Based Hedges (NECO)							
Dec-06	Jan 2008 – Mar 2008	70,000	5.75	-	-	-	-
Jan-07	Jan 2008 – Mar 2008	90,000	6.00	90,000	11.25	-	-
Feb-08	April 2008 – Oct 2008	-	-	-	-	180,000	7.45
Jan-08	April 2008 – Oct 2008	-	-	-	-	120,000	6.80
Jan-08	Nov 2008 - Mar 2009	110,000	6.75	110,000	10.05	-	-
Feb-08	Nov 2008 - Mar 2009	80,000	7.25	80,000	10.05	-	-
Feb-08	Nov 2008 - Mar 2009	-	-	-	-	80,000	8.44
Jan-08	April 2009 - Oct 2009	110,000	6.00	110,000	9.70	-	-
Mar-08	April 2009 - Oct 2009	130,000	6.25	130,000	11.75	-	-
Colorado Interstate Gas (CIG) Based Hedges (Wattenberg)							
Jan-07	Jan 2008 – Mar 2008	123,650	5.25	123,650	9.80	-	-
Feb-08	April 2008 - Oct 2008	-	-	-	-	314,750	7.05
Jan-08	April 2008 - Oct 2008	-	-	-	-	207,350	6.54
Jan-08	Nov 2008 - Mar 2009	237,350	6.50	237,350	10.15	-	-
Feb-08	Nov 2008 - Mar 2009	131,150	7.00	131,150	9.70	-	-
Feb-08	Nov 2008 - Mar 2009	-	-	-	-	131,150	8.18
Jan-08	April 2009 - Oct 2009	237,350	5.75	237,350	8.75	-	-
Mar-08	April 2009 - Oct 2009	214,850	5.75	214,850	9.05	-	-
Oil – NYMEX Based (Wattenberg/North Dakota)							
Oct-07	Jan 2008 – Dec 2008	-	-	-	-	25,900	84.20
Jan-08	Jan 2009 - Dec 2009	-	-	-	-	16,150	84.90

Jan-08	Jan 2009 - Dec 2009	-	-	-	-	16,150	85.40
Jan-08	Jan 2010 - Dec 2010	16,150	70.00	16,150	102.25	-	-
Jan-08	Jan 2010 - Dec 2010	16,150	70.00	16,150	103.00	-	-

We use oil and natural gas commodity derivative instruments to manage price risk for ourselves as well as our sponsored drilling partnerships. We set these instruments for ourselves and the partnerships jointly by area of operation. As volumes produced change, the mix between PDC and the partnerships may change. The above table reflects such revisions necessary to present our positions in effect as of March 3, 2008.

Costs and Expenses

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31, 2007	2006	Change Amount	Percent
	(dollars in thousands, except per Mcfe)			
Oil and gas production and well operations cost	$ 49,264	$ 29,021	$ 20,243	69.8%
Per Mcfe	$ 1.76	$ 1.71	$ (0.05)	2.9%

The increase in oil and gas production and well operations costs for the year was primarily attributable to the 65% increase in production volumes and the increased number of wells and pipeline systems we operate as a result of our 2007 and December 2006 acquisitions. Lifting costs per Mcfe increased 8.9% from $1.23 per Mcfe in 2006 to $1.34 per Mcfe in 2007.

In addition to increased production, the increase in costs is also attributable to increased production and engineering staff, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers associated with the December 2006 and the first quarter 2007 acquisitions and general oil field services inflation pressures.

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Cost of Natural Gas Marketing Activities

Cost of natural gas marketing activities for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Cost of natural gas marketing activities	$ 100,584	$ 130,150	$ (29,566)	-22.7%

The decrease in the costs of natural gas marketing activities in 2007 was primarily due to a decrease in prices and in volumes purchased, along with a $13.4 million decrease in unrealized losses on derivative transactions, from an $11.9 million loss in 2006 to a $1.5 million gain in 2007. In 2007, prices declined by 5% resulting in a $5.2 million decrease in costs and volumes purchased decreased 8% resulting in an additional $8 million decrease in costs. In January 2007, we acquired all of the outstanding partnership interests in 44 of our sponsored drilling partnerships. Since this acquisition, we no longer record the natural gas purchases from the net 423 wells acquired . In total, the natural gas marketing segment's purchased volumes increased by 5%; however, once the now proportionately larger inter-company volumes are eliminated, the net remaining purchases from the natural gas marketing segment declined.

Oil and Gas Well Drilling Operations

Cost of oil and gas well drilling operations for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Cost of oil and gas well drilling operations	$ 2,508	$ 12,617	$ (10,109)	-80.1%

The decrease in cost of oil and gas well drilling operations was due to our change from footage-based drilling arrangements to cost-plus drilling arrangements, which are presented differently for accounting purposes. Beginning with the last sponsored partnership in 2005 (for which revenue generating activities began in 2006), our partnership wells have been drilled on a "cost-plus" basis, which means that we charge the partnerships for the actual cost of the wells plus an agreed upon mark-up above that cost. Prior to that partnership, we had conducted most of our third-party drilling activities on a footage basis, pursuant to which we drilled the wells for a fixed price per foot drilled with additional chargeable items as provided for in the drilling agreement. Our services provided under the cost-plus drilling arrangements are reported net of recovered costs and reflected as revenue in oil and gas well drilling operations, whereas the revenues under the footage-based arrangements were recorded gross of related expenses. For the year ended December 31, 2006, oil and gas well drilling operations included $10 million in expenses related to footage based arrangements. We recorded a $2.1 million loss from footage-based contracts during the year ended December 31, 2006.

Exploration Expense

Exploration expense for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Exploration expense	$ 23,551	$ 8,131	$ 15,420	189.6%

The increase in exploration expense for 2007 is primarily due to an exploration agreement with an unaffiliated party, which we abandoned and for which we recorded charges for liquidated damages of $2.7 million and $1.1 million related to the write-off of the carrying value of the related acreage, $4.2 million in expense related to eight exploratory dry holes, including one which was pending determination at December 31, 2007, compared to one in 2006, $5.5 million geological and geophysical costs related to seismic evaluation of various exploratory prospects, $2.2 million in unproved oil and gas properties amortization, and increased payroll and payroll related costs and other exploratory department costs.

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General and Administrative Expense

General and administrative expense for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Change Amount	Change Percent
	(dollars in thousands, except per Mcfe)			
General and administrative expense	$ 30,968	$ 19,047	$ 11,921	62.6%
Per Mcfe	$ 1.11	$ 1.12	$ (0.01)	0.9%

The increase in general and administrative expense for the year was primarily due to increased costs related to higher payroll and employee benefits costs, including stock-based compensation for the approximately one-third increase in employees during 2007. The increase in management personnel is attributable to the growth we are experiencing, the increase in the cost of recruiting and the higher compensation required to obtain experienced oil and gas personnel.

We have also experienced higher financial statement audit costs related to the late filing of our 2006 Form 10-K, higher compliance costs with the various provisions of the Sarbanes-Oxley Act, increased accounting assistance from third party consulting services and increased legal costs. Although general and administrative expenses increased $11.9 million from 2006 to 2007, the rate per Mcfe declined from $1.12 per Mcfe to $1.11 per Mcfe produced.

Depreciation, Depletion and Amortization

DD&A expense for the years ended December 31, 2007 and 2006, are presented below.

	Year Ended December 31, 2007	Year Ended December 31, 2006	Change Amount	Change Percent
	(dollars in thousands, except per Mcfe)			
Depreciation, depletion and amortization	$ 70,844	$ 33,735	$ 37,109	110.0%
Per Mcfe	2.53	1.99	0.54	27.1%

The 65% higher production volumes realized in 2007 resulted in a $20.7 million increase in DD&A expense in 2007 compared to 2006. The remaining period to period change is primarily related to the cost of acquisitions of proved mineral interest and the addition of wells, related equipment and facilities. These acquisitions have been made at current market prices, which are higher than our historical cost of property and reserves. The increasing cost of well drilling, completion and equipping of new wells along with the higher current costs of the acquisitions during 2007 is reflected in the DD&A rates for oil and gas properties as shown in the table below for our significant areas of operations.

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(per Mcfe)	
	$ 1.32	$ 1.13

Appalachian Basin		
Michigan Basin	1.28	0.83
Rocky Mountain Region:		
Wattenberg Field (1)	2.99	2.34
Piceance Basin	2.27	1.83
NECO	1.45	1.26

(1) This field contains 89.1% of our oil production.

The weighted average DD&A rate for oil and gas properties increased to $2.37 per Mcfe in 2007 from $1.87 per Mcfe in 2006. DD&A expense for non-oil and gas properties, which are not included in the above table, increased to $4.3 million in 2007 from $2 million in 2006.

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The DD&A rate for oil and gas properties declined from $2.50 per Mcfe from the third quarter of 2007 to $2.12 per Mcfe in the fourth quarter of 2007. The major reason for the decline was the upward revision in our new reserve report as of December 31, 2007, compared to 2006 primarily due to an upward revision in production and higher commodity prices, partially offset by increased operating costs. The average price for natural gas in the reserve report was $6.77 per Mcf at December 31, 2007, compared to $4.96 per Mcf at December 31, 2006, an increase of $1.81 per Mcf or 36.5%. The average price for oil was $80.67 per barrel at December 31, 2007, compared to $57.70 per barrel at December 31, 2006, an increase of $22.97 per barrel or 39.8%.

Gain on Sale of Leaseholds

In July 2006, we entered into a purchase and sale agreement with an unaffiliated party regarding the sale of our undeveloped leasehold located in the Grand Valley Field, Garfield County, Colorado, as filed with the Securities and Exchange Commission, or SEC, as Exhibit 10.3 to the Form 10-Q for the period ended September 30, 2006. Total proceeds from the sale were $353.6 million, of which we recognized a $328 million gain on sale of leasehold in the third quarter of 2006.

In May 2007, we entered into a letter agreement amending the above mentioned purchase and sale agreement, relieving us of our obligation, in its entirety, to either drill 16 wells or pay liquidated damages of $1.6 million per undrilled well. As a result, we recognized the remaining deferred gain of $25.6 million in the second quarter of 2007.

In December 2007, we sold to the same unaffiliated party a portion of our North Dakota properties for approximately $34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and approximately 72,000 net undeveloped acres. We recorded a gain on sale of leaseholds of $7.7 million in the fourth quarter of 2007.

Non-operating Income/Expense

Non-operating income and expense for the years ended December 30, 2007 and 2006, are presented below.

	Year Ended December 31,		Change	
	2007	2006	Amount	Percent
	(dollars in thousands)			
Non-operating income (expense):				
Interest income	$ 2,662	$ 8,050	$ (5,388)	-66.9%
Interest expense	$ (9,279)	$ (2,443)	$ (6,836)	279.8%

The decrease in interest income for the quarter is a result of lower cash balances earning interest compared to the same period last year, primarily due to the $353.6 million in cash proceeds from the sale of undeveloped leaseholds in July 2006. The proceeds were reinvested in oil and gas properties by mid-January 2007. The increase in interest expense in 2007 was due to significantly higher average outstanding balances of our credit facility, offset by capitalized construction period interest of $3 million in 2007 compared to $1.6 million in 2006. We utilize our daily cash balances to reduce the line of credit, lowering the costs of interest.

Provision for Income Taxes

The effective income tax rate for the provision for income taxes for 2007, was 38.7%, relatively unchanged from 38.6% for 2006. The benefit we received from the 2007 domestic production deduction was offset by non-deductible income tax and production tax penalties that were expensed during the year.

Year Ended December 31, 2006, Compared to December 31, 2005

Management Overview

Net Income

	Year Ended December 31, 2006	Year Ended December 31, 2005	Change Amount	Change Percent
	(dollars in thousands, except per share data)			
Net income	$ 237,772	$ 41,452	$ 196,320	473.6%
Diluted earnings per share	$ 15.11	$ 2.52	$ 12.59	499.6%

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Revenues

Revenues for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31, 2006	2005	Change Amount	Percent
	(dollars in thousands)			
Revenues:				
Oil and gas sales	$ 115,189	$ 102,559	$ 12,630	12.3%
Sales from natural gas marketing activities	131,325	121,104	10,221	8.4%
Oil and gas well drilling operations	17,917	99,963	(82,046)	-82.1%
Well operations and pipeline income	10,704	8,760	1,944	22.2%
Oil and gas price risk management gain (loss) net	9,147	(9,368)	18,515	-197.6%
Other	2,221	2,180	41	1.9%
Total revenues	$ 286,503	$ 325,198	$ (38,695)	-11.9%

The decrease in revenues was primarily attributable to a decrease in drilling revenues of $82.1 million partially offset by the increased oil and gas sales from both gas marketing activities and our share of production for a total of $22.9 million and the swing from a $9.4 million loss in oil and gas price risk management for the year ended December 31, 2005, to a gain of $9.1 million for the year ended December 31, 2006. See Drilling Operations below for an explanation of the effect the new cost-plus drilling arrangements and related accounting had on drilling revenues for the year 2006.

Costs and Expenses

Costs and expenses for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31, 2006	2005	Change Amount	Percent
	(dollars in thousands)			
Costs and expenses:				
Oil and gas production and well operations cost	$ 29,021	$ 20,400	$ 8,621	42.3%
Cost of natural gas marketing activities	130,150	119,644	10,506	8.8%
Cost of oil and gas well drilling operations	12,617	88,185	(75,568)	-85.7%
Exploration expense	8,131	11,115	(2,984)	-26.9%
General and administrative expense	19,047	6,960	12,087	173.7%
Depreciation, depletion and amortization	33,735	21,116	12,619	59.8%
Total costs and expenses	$ 232,701	$ 267,420	$ (34,719)	-13.0%

The decrease in costs was primarily attributable to decreases in the cost of oil and gas well drilling operations of $75.6 million and exploration cost of $3 million offset in part by increases in the cost of gas marketing activities of $10.5 million, oil and gas production and well operations costs of $8.6 million, general and administrative expenses of $12.1 million and depreciation, depletion and amortization of $12.6 million. See Drilling Operations below for an explanation of the effect of the new cost plus drilling arrangements and related accounting had on drilling expenses for the year 2006.

Results of Operations

Revenues

Oil and Gas Sales

Revenues for oil and gas sales for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31, 2006	Year Ended December 31, 2005	Change Amount	Change Percent
	(dollars in thousands)			
Oil and gas sales	$ 115,189	$ 102,559	$ 12,630	12.3%

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The increase was due to a 24% increase in volumes sold at lower average sales prices of natural gas and, in part, to higher average sales prices and higher volumes sold of oil. The volume of natural gas sold for the year ended December 31, 2006, was 13.2 Bcf at an average price of $5.91 per Mcf compared to 11.0 Bcf at an average sales price of $7.29 per Mcf for the year ended December 31, 2005. Oil sales for the year ended December 31, 2006, were 631,000 barrels at an average sales price of $59.33 per barrel compared to 439,000 barrels at an average sales price of $50.56 per barrel for the year ended December 31, 2005. The increase in natural gas and oil volumes was the result of our increased investment in oil and gas properties, primarily the increase in net wells drilled for our own account, recompletions of existing wells, and the investment in oil and gas properties we own in drilling program partnerships.

Oil and Gas Production

Our oil and gas production by area of operations along with average sales price (excluding derivative losses) is presented below:

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
Natural Gas (Mcf)				
Appalachian Basin	1,451,729	1,631,552	(179,823)	-11.0%
Michigan Basin	1,399,852	1,555,958	(156,106)	-10.0%
Rocky Mountains	10,309,203	7,843,250	2,465,953	31.4%
Total	13,160,784	11,030,760	2,130,024	19.3%
Average Sales Price	$ 5.91	$ 7.29	$ (1.38)	-18.9%
Oil (Bbls)				
Appalachian Basin	1,837	3,973	(2,136)	-53.8%
Michigan Basin	4,439	4,732	(293)	-6.2%
Rocky Mountains	625,119	430,266	194,853	45.3%
Total	631,395	438,971	192,424	43.8%
Average Sales Price	$ 59.33	$ 50.56	$ 8.77	17.3%
Natural Gas Equivalents (Mcfe)*				
Appalachian Basin	1,462,751	1,655,390	(192,639)	-11.6%
Michigan Basin	1,426,486	1,584,350	(157,864)	-10.0%
Rocky Mountains	14,059,917	10,424,846	3,635,071	34.9%
Total	16,949,154	13,664,586	3,284,568	24.0%
Average Sales Price	$ 6.80	$ 7.51	$ (0.71)	-9.5%

*One Bbl of oil is equal to the energy equivalent of six Mcf of natural gas.

Sales from Natural Gas Marketing Activities

	Year Ended December 31,	Change

	2006	2005	Amount	Percent
		(dollars in thousands)		
Sales from natural gas marketing activities	$ 131,325	$ 121,104	$ 10,221	8.4%

The increase in revenue was the result of a 9% increase in volumes sold at prices 17.2% lower than 2005 levels and significant unrealized gains on derivative transactions which amounted to approximately $12.3 million for the year ended December 31, 2006, compared to unrealized losses of $8.5 million for the year ended December 31, 2005.

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Oil and Gas Drilling Operations

Revenues for oil and gas drilling operations for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands)			
Oil and gas well drilling operations	$ 17,917	$ 99,963	$ (82,046)	-82.1%

During the first quarter of 2006, we began operating and recognizing revenues for our cost-plus service arrangements with new partnerships, in addition to our footage-based drilling arrangements on earlier partnerships. The cost-plus drilling arrangements became effective with the private program partnership we funded in December 2005 and continued in the 2006 partnership funded on September 1, 2006. Drilling revenues for the year ended December 31, 2006, were $17.9 million, net of $74.6 million of costs related to drilling arrangements accounted for on the cost-plus basis, compared to $100 million for the year ended December 31, 2005, a decrease of $82.1 million. The decrease was primarily due to the change in our drilling contracts, which resulted in net revenue recognition related to the new contracts.

Although we changed to cost-plus drilling arrangements with our two recent partnerships, prior footage-based contracts continue to be in effect, and realized a loss of $2.1 million during 2006. This loss contributed to the decrease in the drilling and development segment gross margin from $11.8 million for the year ended December 31, 2005, to $5.3 million for the year ended December 31, 2006. This loss was due to some drilling and completion difficulties incurred and significantly increasing well drilling and completion costs, particularly the costs of fracturing and rising steel costs for casing and other well equipment and oil field services. Future partnerships will be drilled on a “cost-plus basis,” which should reduce these fluctuations in drilling gross margins. See Note 1, Summary of Significant Accounting Policies, to our accompanying consolidated financial statements.

Well Operations and Pipeline Income

Revenues for Well operations and pipeline income for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands)			
Well operations and pipeline income	$ 10,704	$ 8,760	$ 1,944	22.2%

The increase in revenue was due to an increase in the number of wells and pipeline systems we operate for drilling partnerships, as well as for third parties.

Oil and Gas Price Risk Management Gain (Loss), Net

Oil and gas price risk management, net for the years ended December 31, 2006 and 2005, is presented below.

Change

	Year Ended December 31,			
	2006	2005	Amount	Percent
	(dollars in thousands)			
Oil and gas price risk management gain (loss), net	$ 9,147	$ (9,368)	$ 18,515	-197.6%

For the year ended December 31, 2006, we recorded realized gains of $1.9 million and unrealized gains of $7.2 million compared to the year ended December 31, 2005, which is comprised of unrealized losses of $3 million and realized losses of $6.4 million. Our strategy is to provide protection in the event of declining oil and natural gas prices. During 2006, we experienced decreasing natural gas and rising oil pricing environments. This trend and the timing, extent and nature of the derivative trades executed caused us to record gains in our derivative transactions as a result of gains on the natural gas positions. Oil and gas price risk management gains (losses), net is comprised of the change in fair value of oil and natural gas derivatives related to oil and gas production (this line item does not include commodity-based derivative transactions related to transactions from gas marketing activities, which are included in the revenues and expenses of the related purchase and sales transactions).

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Other Income

Other income, consisting primarily of management fees associated with Company-sponsored drilling programs, was relatively unchanged at $2.2 million for each of the years ended December 31, 2006 and 2005.

Costs and Expenses

Oil and Gas Production and Well Operations Costs

Oil and gas production and well operations costs for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands, except per Mcfe)			
Oil and gas production and well operations cost	$ 29,021	$ 20,400	$ 8,621	42.3%
Per Mcfe	$ 1.71	$ 1.49	$ 0.22	14.7%

The increase in cost was due to the increased production costs associated with the 24% increase in production volumes, along with the increased number of wells and pipelines we operate. Lifting costs per Mcfe increased from $1.19 per Mcfe for the year ended December 31, 2005, to $1.23 per Mcfe for the year ended December 31, 2006, due to the significant inflation of oil field production services along with additional well workovers and production enhancements work performed.

Cost of Natural Gas Marketing Cost

Cost of natural gas marketing activities for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands)			
Cost of natural gas marketing activities	$ 130,150	$ 119,644	$ 10,506	8.8%

The increase in cost was due to higher average volumes of natural gas purchased for resale and a significant increase in unrealized losses on derivative transactions, which amounted to approximately $11.9 million for the year ended December 31, 2006, compared to an unrealized gain of $8.3 million for the year ended December 31, 2005. Income before income taxes for our natural gas marketing subsidiary increased from $1.7 million for the year ended December 31, 2005, to $1.8 million for the year ended December 31, 2006. Based on the nature of our gas marketing activities, derivatives did not have a significant effect on our net margins from marketing activities during either period.

Cost of Oil and Gas Well Drilling Operations

Cost of oil and gas well drilling operations for the years ended December 31, 2006 and 2005, are presented below.

	Year Ended December 31,	Change

	2006	2005	Amount	Percent
		(dollars in thousands)		
Cost of oil and gas well drilling operations	$ 12,617	$ 88,185	$ (75,568)	-85.7%

The decrease in costs is primarily attributable to our revenue reporting for our new cost-plus drilling arrangements, which reduced drilling costs by $74.6 million for the year as discussed above.

The new cost-plus drilling arrangement eliminates our risk of loss from the contract drilling services we provide the partnerships. Our drilling revenues and corresponding costs are presented net as a one-lined income statement item representing only the gross profit portion of the drilling arrangement. The new cost-plus contract affected 2006 by reducing drilling revenues and drilling costs by $74.6 million as outlined in the table below (in millions):

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	Year ended December 31, 2006			2005
	Drilling Service Revenue/Cost	Direct Reimbursed Cost	Revenue/Cost including reimbursement from Partnerships	Drilling Service Revenue/Cost
Oil and gas well drilling operations	$ 17.9	$ 74.6	$ 92.5	$ 100.0
Total revenues	286.5	74.6	361.1	325.2
Cost of oil and gas well drilling operations	12.6	74.6	87.2	88.2
Total costs and expenses	232.7	74.6	307.3	267.4

Exploration Expense

Exploration expense for the years ended December 31, 2006 and 2005, is presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands)			
Exploration expense	$ 8,131	$ 11,115	$ (2,984)	-26.8%

The decrease in expense is primarily attributable to fewer exploratory dry holes being drilled in 2006. In 2006, exploratory dry hole expenses were $1.8 million compared to $11.1 million in 2005. In 2006, we recorded an impairment charge of $1.5 million on our Nesson Field in North Dakota and incurred geological and geophysical costs of $2.2 million which relate to an exploratory seismic program initiated on our Northeast Colorado properties. We anticipate additional geological and geophysical activities and related costs in 2007.

General and Administrative Expense

General and administrative expense for the years ended December 31, 2006 and 2005, is presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands, except per Mcfe)			
General and administrative expense	$ 19,047	$ 6,960	$ 12,087	173.7%
Per Mcfe	$ 1.12	$ 0.51	$ 0.61	119.6%

A substantial portion of the increase was attributable to the costs of our financial statement restatement and the restatement of our sponsored partnerships' financial statements. In addition, we continue to experience a high level of costs complying with the various provisions of the Sarbanes-Oxley Act, in particular Section 404 (internal and external costs of assessing Internal Controls over Financial Reporting). Approximately $3.2 million of the increase is attributable to the external costs incurred in connection with restatement of financial statements and compliance with the provisions of the Sarbanes-Oxley Act. Finally, we added over 39 new employees in 2006 and experienced increased payroll and payroll-related costs of $4.3 million.

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Depreciation, Depletion, and Amortization

DD&A expense for the years ended December 31, 2006 and 2005, is presented below.

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands, except per Mcfe)			
Depreciation, depletion and amortization	$ 33,735	$ 21,116	$ 12,619	59.8%
Per Mcfe	$ 1.99	$ 1.55	$ 0.44	28.4%

The increase in cost was due to the 24% increase in production volumes, significant investments in oil and gas properties by us in 2006, and increased per unit cost of depreciation, depletion and amortization as a result of rising costs of drilling, completing and equipping wells.

Gain on Sale of Leaseholds

Gain on sale of leaseholds for the year ended December 31, 2006, was $328 million compared to $7.7 million in 2005, an increase of $320.3 million. The increase is attributable to the sale of undeveloped leaseholds in Garfield County, Colorado in the third quarter of 2006, for which a portion of the gain to be recognized was deferred to future periods. See Note 16, Sale of Oil and Gas Properties, to our accompanying consolidated financial statements. The prior year period included a gain of $6.2 million for the sale of a portion of one of our undeveloped leases in Garfield County, Colorado and a gain of $1.5 million for the sale to an unaffiliated party of some Pennsylvania wells.

Non-Operating Income/Expense

	Year Ended December 31,		Change	
	2006	2005	Amount	Percent
	(dollars in thousands)			
Non-operating income (expense):				
Interest income	$ 8,050	$ 898	$ 7,152	796.4%
Interest expense	$ (2,443)	$ (217)	$ (2,226)	1025.8%

The increase in interest income was primarily due to the interest on the temporary investment, in cash equivalents, of cash proceeds of $353.6 million from the sale of undeveloped leaseholds. The increase in interest expense was due to rising interest rates on significantly higher average outstanding balances of the credit facility, offset in part by $1.6 million of capitalized construction period interest. We utilize our daily cash balances to reduce our line of credit to lower our cost of borrowing. The average outstanding debt balance for the year ended December 31, 2006, was $44.2 million compared to $4.1 million for the year ended December 31, 2005.

Provision for Income Taxes

The effective income tax rate for our provision for income taxes increased from 37.3% for the year ended December 31, 2005, to 38.6% for the year ended December 31, 2006, primarily as a result of the gain on sale of leasehold being taxed at the full federal and state statutory rates because there are no offsetting permanent deductions, such as percentage depletion, available on such a sale. In addition, the domestic production activities deduction was not utilized in 2006 due to our decision, for tax purposes only, to expense the majority of our intangible drilling costs.

Liquidity and Capital Resources

Cash flow from operations and our bank credit facility are our primary sources of liquidity to meet operating expenses and fund capital expenditures (other than for certain acquisitions). Recently, as of February 8, 2008, we completed the issuance and sale of $203 million of 12% senior notes due 2018 for net proceeds received of approximately $196 million. The completion of the issuance and sale of our senior notes enabled us to reduce our short term liquidity risk through the terming out of our existing credit facility of November 2010 and extending it until February 2018. The repayment of the amounts outstanding under the credit facility with a portion of the net proceeds from the senior notes provided $234.1 million of available borrowing capacity. As of February 29, 2008, we have access to all of the $234.1 million facility as it was un-drawn. Additionally, we believe that our continued drilling activities will allow us, through our permitted borrowing base re-determinations, to increase the borrowing capacity of the credit facility. See Long Term Debt discussed below.

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Our 2008 capital expenditure budget is $255 million: $194 million for drilling and development; $50 million for exploratory drilling, land acquisitions and seismic activities; and $11 million for other capital expenditures. We believe this level of exploration and development activity will be sufficient to increase our proved oil and natural gas reserves in 2008 and increase our total production by between 30% and 40% (without regard to any additional acquisitions that may be completed in 2008). We retain a significant degree of control over the timing of our capital expenditures, which permits us to defer or accelerate certain capital expenditures if necessary to address any potential liquidity issues. In addition, higher drilling and field operating costs, drilling results that alter planned development schedules, acquisitions or other factors could cause us to revise our drilling program, which programs are largely discretionary. We believe that our available cash, cash provided by operating activities and funds available under our revolving credit facility will be sufficient to fund our operations, debt service, partnership drilling obligation, general and administrative expenses, capital budget, and short-term contractual obligations for the next few years.

Changes in market prices for oil and natural gas directly affect the level of our cash flow from operations. While a decline in oil and natural gas prices would affect the amount of cash flow that would be generated from operations, we had oil and natural gas hedges in place, as of March 3, 2008, covering 41% of our expected oil production and 62% of our expected natural gas production in 2008, thereby providing price certainty for a substantial portion of our 2008 cash flow. Depending on changes in oil and natural gas futures markets and our view of underlying oil and natural gas supply and demand trends, we may increase or decrease our current hedging positions. Our oil and natural gas hedges as of December 31, 2007, are detailed in Item 7A of this report.

We have utilized public and private markets, proceeds from bank borrowings and cash flow from operations for our capital resources and liquidity. To date, our primary use of capital has been for the acquisition and development of oil and gas properties. As we pursue growth, we will continually monitor the capital resources available to meet our future financial obligations and planned capital expenditures. Our future success in replacing and growing reserve levels will be highly dependent on the capital resources available and our success in drilling for or acquiring additional reserves. We actively review acquisition opportunities on an ongoing basis. If we were to make significant additional acquisitions for cash, we would need to borrow additional amounts under our current credit facility, if available, or obtain additional debt or equity financing.

On January 7, 2008, we announced that we do not plan to sponsor new drilling partnerships in 2008 in order to focus our efforts on continuing our growth through drilling and exploration. In 2008, we expect to recognize $7.8 million in oil and gas well drilling revenue related to the 2007 drilling partnership.

Operating Cash Flows

Net cash provided by operating activities was $60.3 million in 2007 compared to $67.4 million in 2006, a decrease of $7.1 million. The decrease in cash provided by operating activities was due primarily to the following:

- Increased costs from production and well operations related to the 65% increase in production, as well as the increases in exploration and general and administrative expenses, partially offset by the increase in oil and gas sales revenues;
- Federal and state taxes payable decreased primarily due to the 2007 payment of taxes of the non deferred portion of the gain on the sale of the Grand Valley Field Acreage;
- The decrease in accounts payable is primarily due to the timing of payments related to the purchase of properties and equipment;
- Current restricted cash increased due to the funding in 2007 of an escrow account for amounts due limited partners as a result of over withholding of estimated production taxes;
- Accounts payable to affiliates decreased for the partnership's share of unpaid premiums and unrealized losses related to hedge positions at December 31, 2007;

- Production tax liability increased due to the 65% increase in oil and gas production volumes in 2007; and
- Advances for future drilling contracts increased due to the timing of drilling and development activities on behalf of our 2007 sponsored drilling partnership.

Net cash provided by operating activities was $67.4 million in 2006 compared to $112.4 million in 2005, a decrease of $45 million.
The decrease in cash provided by operating activities was due primarily to the following:

- Increased costs from production and well operations related to the 24% increase in production volumes and increased number of wells;
- Increase in general and administrative costs due to the Company's financial statement restatement and incremental costs to comply with various provisions of Sarbanes-Oxley partially offset by; and
- The increase in oil and gas sales revenues due to the 24% increase in production volumes at lower unit sales prices.

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Investing Cash Flows

Net cash used in investing activities was $267.4 million in 2007 compared to $9.6 million in 2006, an increase of $257.8 million.
The increase in cash used in investing activities was due primarily to the following:

- An approximate $93 million increase in capital expenditures is primarily due to an increase in the number of wells drilled to 349 in 2007 from 231 in 2006 or approximately $72 million; and
- Acquisitions of oil and natural gas properties of approximately $256 million;

Partially offset by:
- The 2006 acquisition of Unioil of approximately $18 million; and
- The net effect of the transfer of the funds from the Like kind exchange, or LKE, from restricted cash and the proceeds from the 2006 sale of the Grand Valley Field acreage.

Net cash used in investing activities was $9.6 million in 2006 compared to $94 million in 2005, a decrease of $84.4 million. The decrease in cash used in investing activities was due primarily to the following:

- An approximate $49 million increase in the capital expenditures; and
- Approximately $192 million increase in restricted/designated cash due to acquisitions;

Partially offset by:
- An approximate $344 million increase in proceeds from sale of leasehold/assets due to the sale of the Grand Valley Field acreage in July 2006.

Financing Cash Flows

Net cash provided by financing activities was $97.5 million in 2007 compared to $46.5 million in 2006, an increase of $51 million. The increase in cash provided by financing activities was due primarily to the following:

- A decrease of treasury stock purchases of approximately $66 million offset by the net change in short and long term debt from borrowing activities.

Net cash provided by financing activities was $46.5 million in 2006 compared to net cash used in financing activities of $5.3 million in 2005, an increase of $51.8 million. The increase in cash provided by financing activities was due primarily to the following:

- An approximate $110 million increase in proceeds from the issuance of long-term and short-term debt, net of retirement of debt, in 2006;

Partially offset by:
- An approximate $59 million of additional treasury stock purchases.

Working Capital

Our working capital usage for 2007 was $50.2 million. At December 31, 2007, we had available borrowing capacity under our bank credit facility of $60 million. Historically, we have satisfied our working capital needs through free cash flow and borrowings under our credit facility. We may need to raise additional capital in the bank, private and public markets to fund future acquisitions and increases in capital expenditure levels. We expect to continue to maintain adequate liquidity to meet our obligations on an ongoing basis. If we are unable to raise incremental capital, future capital expenditures and acquisitions may be affected. We used most of the net proceeds of approximately $196 million from our February 8, 2008, $203 million senior notes offering to repay the $180 million then drawn under our bank credit facility. Upon the issuance of our senior notes on February 8, 2008, our activated commitment of $295 million was mandatorily reduced to $234.1 million. As of February 29, 2008, our outstanding credit facility was un-drawn. Based on near-term cash flow projections, the discretionary nature of our capital program, our bank credit facility capacity and the demonstrated ability to raise capital in bank, private and public markets, we believe that we have sufficient liquidity to fund our operations in 2008.

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Long-Term Debt

We have a credit facility with JPMorgan Chase Bank, N.A., or JPMorgan, and BNP Paribas, as amended, dated as of November 4, 2005, with an activated commitment of $295 million as of December 31, 2007. The credit facility, through a series of amendments, includes commitments from Wachovia Bank, N.A., Bank of Oklahoma, Allied Irish Banks p.l.c., Guaranty Bank, BSB, Royal Bank of Canada and The Royal Bank of Scotland, plc. The maximum allowable commitment under the current credit facility is $400 million. The credit facility is subject to and secured by required levels of natural gas and oil and reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. We are required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate or adjusted LIBOR at our discretion. The alternative base rate is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus 0.5%. Alternative base rate borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%, based upon the outstanding balance under the credit facility. The credit agreement requires, among other things, the maintenance of certain working capital and tangible net worth ratios. No principal payments are required until the credit agreement expires on November 4, 2010.

Effective August 9, 2007, the first amendment to our credit facility waived our working capital covenant until the earlier of (i) a debt or equity transaction resulting in net proceeds, as defined, to us of at least $200 million or (ii) July 1, 2008, which was further extended to October 1, 2008, effective October 16, 2007. In accordance with the first amendment, the alternative base rate was increased by 0.375% as long as the waiver of the working capital covenant was in effect.

On February 8, 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018 for net proceeds received of approximately $196 million; see Note 5, Long Term Debt, to our accompanying consolidated financial statements. In accordance with the senior credit agreement, upon the issuance of any senior notes, the borrowing base then in effect on our credit facility shall automatically be reduced by $300 for each $1,000 in stated principal amount of such senior notes issued by us. Accordingly, effective February 8, 2008, our borrowing base under the credit facility was reduced from $295 million to $234.1 million. Further, our senior notes issuance meets the requirements of a debt transaction described above, and thus, the testing of our working capital covenant will resume with our quarter ending March 31, 2008.

As of December 31, 2007, the outstanding balance under our credit facility was $235 million compared to $117 million, excluding the overline note discussed below, as of December 31, 2006. The borrowing rate on the outstanding balance was 7.07% and 7.79% at December 31, 2007, and December 31, 2006, respectively. Amounts outstanding under the credit facility were secured by substantially all of our properties. We were in compliance with all covenants at December 31, 2007, and expect to remain in compliance throughout 2008.

On December 19, 2006, we executed, pursuant to our credit facility, an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.8% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January 2007.

Drilling Programs

In August 2007, we completed our sponsored drilling partnership offering, Rockies Region 2007 Limited Partnership, and received subscriptions of approximately $90 million. We contributed $38.7 million, which represented 43% of the $90 million of total subscriptions received, for our general partner capital contribution. Drilling for the partnership commenced during the third quarter and continued in the fourth quarter of 2007. From inception to December 31, 2007, $5.3 million in revenues has been recognized. On December 28, 2007, the drilling partnership paid to us $54 million, in accordance with the partnership agreement, to secure intangible drilling cost tax deductions for the investing partners. This payment is included in advances for future drilling contracts on our consolidated balance sheet. In early January 2008, we used this advance to pay down our credit facility. Drilling and completion operations for the 2007 drilling program will continue through the first half of 2008. We expect to recognize additional revenue of approximately $7.8 million in our oil and gas well drilling operations related to this partnership during 2008. In January 2008, we announced that we do not plan to sponsor new drilling partnerships in 2008 in order to focus our effort on maximizing the value of the existing partnerships and our continuing growth through drilling and exploration.

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Treasury Share Purchases

On October 16, 2006, our Board of Directors approved a second 2006 share purchase program authorizing us to purchase up to 10% of our then outstanding common stock (1,477,109 shares) through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that we deem appropriate. Shares are generally purchased at fair market value based on the closing price on the date of purchase. Total shares purchased in 2007 pursuant to the program were 12,020 common shares at a cost of $0.6 million ($53.78 average price paid per share), including 5,187 shares from our executive officers at a cost of $0.3 million ($57.93 price paid per share). Shares purchased pursuant to the plan were primarily to satisfy the statutory minimum tax withholding requirement for restricted stock that vested in 2007. All shares were subsequently retired. At December 31, 2007, the remaining number of shares that may be purchased under this program is 1,465,089, see Item 5, Market for Registrant's Common Equity and Related Stockholders Matters - Issuer Purchases of Equity Securities, of this report for a reconciliation of activities.

Pursuant to our senior notes indenture entered on February 8, 2008, any future purchases are limited, see Note 19, Subsequent Events, to our accompanying consolidated financial statements.

On February 25, 2008, pursuant to a separation agreement, we purchased 50,000 shares of our common stock from one of our executive officers at a cost of $3.4 million, or $67.92 per share. See Note 19, Subsequent Events, to our accompanying consolidated financial statements.

Contractual Obligations and Contingent Commitments

The table below sets forth our contractual obligations and contingent commitments as of December 31, 2007:

Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
		Payments due by period (in thousands)			
Debt (1)	$ 235,000	$ -	$ 235,000	$ -	$ -
Interest (2)	47,255	16,613	30,642	-	-
Operating leases	4,460	1,948	1,827	685	-
Asset retirement obligations	20,781	50	100	100	20,531
Rig commitments (3)	24,669	8,810	15,859	-	-
Drilling commitments (4)	3,655	-	1,155	-	2,500
Other liabilities (5)	8,876	1,133	720	720	6,303
Total	$ 344,696	$ 28,554	$ 285,303	$ 1,505	$ 29,334

(1) Long-term debt does not include interest.

(2) Interest based on balance at December 31, 2007, at an applied rate of 7.07%.

(3) Drilling rig commitments in the above table do not include future adjustments to daily rates as provided for in the agreements as such increases are not predictable and are only included in the above obligation table upon notification to us by the contractor of an increase in the rate.

(4) Amounts represent our maximum obligation for potential liquidating damages if we do not comply with certain drilling and development agreements. See Note 8, Commitments and Contingencies, to our accompanying consolidated financial statements. These amounts do not include advances for future drilling contracts totaling

$68.4 million at December 31, 2007.

(5) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation. Further, includes unrecognized tax benefits totaling $0.9 million pursuant to FIN No. 48.

(6) Table does not include maximum annual repurchase obligation of $6.7 million as of December 31, 2007, see Note 8, Commitments and Contingencies, to our accompanying consolidated financial statements.

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Commitments and Contingencies

As managing general partner of 33 partnerships (see Item 1. Business – Drilling and Development Conducted for Company Sponsored Partnerships, we have liability for any potential casualty losses in excess of the partnership assets and insurance. In January 2007, we purchased the remaining working interests in 44 of 77 partnerships, which we sponsored in the late 1980s and 1990s (see Note 2, Acquisitions, to our accompanying consolidated financial statements). We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings, see Note 8, Commitments and Contingencies – Litigation, to our accompanying consolidated financial statements included in this report.

From time to time we are a party to various other legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse affect on our business, financial condition, results of operations, or liquidity.

Sale of Undeveloped Leaseholds

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

Pursuant to the purchase and sale agreement, we were obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per undrilled well for a total contingent obligation of $25.6 million, which was reflected as a deferred gain on sale of leaseholds on the balance sheet as of December 31, 2006. In May 2007, we entered into a letter agreement amending the original purchase and sale agreement. The letter agreement relieved us of the obligation, in its entirety, to either drill 16 wells or pay liquidated damages, resulting in the recognition of the remaining $25.6 million deferred gain on sale of leaseholds in the second quarter of 2007. Pursuant to the letter agreement, we were obligated to drill six wells on specifically identified acreage. As of December 31, 2007, we had drilled all six wells, which were drilled on the unaffiliated party's leasehold for its benefit and at its cost.

In conjunction with the purchase and sale agreement described above, we entered into a LKE agreement, in accordance with Section 1031 of the Internal Revenue Code, with a “qualified intermediary.” Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. We had until mid-January 2007 to close any acquisition of suitable like-kind property, allowing us to take advantage of the income tax deferral benefits of a LKE transaction. See below a discussion of the acquisition of suitable like-kind properties.

In December 2007, we sold to the same unaffiliated party a portion of our North Dakota properties for approximately $34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and leasehold interests in approximately 72,000 net undeveloped acres. The reduction in our production and proved reserves as a result of this transaction is not material. We recorded a gain on sale of leaseholds of $7.7 million in the fourth quarter of 2007. The proceeds from the sale were used to pay down debt. Following the sale, as it relates to our North Dakota properties, we retain ownership in three producing wells in

Dunn County, ten producing wells in Burke County and approximately 60,000 acres of undeveloped leasehold in Burke County.

Acquisition of Oil and Gas Properties

Acquisition of Section 1031 – LKE Properties

In January 2007, we completed our acquisitions of suitable like-kind properties in accordance with the LKE agreement we entered into in connection with our sale of undeveloped leaseholds located in Grand Valley Field, Garfield Country, Colorado, in July 2006. We paid cash consideration for the acquired oil and gas properties totaling $188.9 million, as described below.

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EXCO Resources Inc. On January 5, 2007, we completed our purchase of EXCO Resources Inc.'s producing properties and remaining undeveloped drilling locations and acreage in the Wattenberg Field of the DJ Basin, Colorado. The cash consideration paid for the EXCO properties was $130.2 million. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 oil and gas wells (approximating 25.5 Bcfe, net of royalty interests, proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold interests. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. We operate the assets and hold a majority working interest in the properties.

Company-Sponsored Partnerships. On January 10, 2007, we completed the purchase of a majority interest in 44 of our sponsored partnerships for $56.6 million. This transaction was not effected pursuant to purchase requests by investor partners (see Note 8, Commitments and Contingencies, to our accompanying consolidated financial statements). The wells are located in the Appalachian Basin, Michigan, and Colorado. The transaction resulted in an increase of 423 net wells that we currently operate.

Other. We acquired from unaffiliated parties undeveloped leaseholds in Erath County, Texas for $2.1 million.

Other Acquisitions

On February 22, 2007, we acquired from an unaffiliated party 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $12 million. The acquisition encompassed daily production of approximately 668 Mcfe (520 Mcf of gas and 25 barrels of oil per day), net to the interests acquired, 100 or more undeveloped drilling locations, 19.1 Bcfe of proved reserves, and an additional 7.5 Bcfe of probable reserves.

On October 30, 2007, with an effective date of October 1, 2007, we purchased from unrelated parties a majority working interest in 762 natural gas wells located in southwestern Pennsylvania for approximately $54 million. We estimated that the acquisition included approximately 47 Bcfe of reserves, or 31 Bcfe of proved reserves and 16 Bcfe of unproved reserves. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage.

Critical Accounting Policies and Estimates

We have identified the following policies as critical to business operations and the understanding of our results of operations. This is not a comprehensive list of all of the accounting policies. In many cases, the accounting treatment of a particular transaction is specifically dictated by accounting principles generally accepted in the United States, with no need for our judgment in the application. There are also areas in which our judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and we may use significant judgment in the application; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, we use our judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see Note 1, Summary of Significant Accounting Policies, to our accompanying consolidated financial statements. Our critical accounting policies and estimates are as follows:

Revenue Recognition

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

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

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

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

Oil and gas well drilling operations. Our drilling segment recognizes revenue from drilling contracts with sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. We utilize this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. In addition, we offer our drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships and, consequently, different revenue reporting policies pursuant to Emerging Issues Task Force, or EITF, Issue No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent.

The first cost-plus drilling service arrangement was entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Due to the fixed-fee-percentage nature of our revenues from these services, we have determined that, in substance, we are acting as an agent, without risk of loss during the performance of the drilling activities. Accordingly, our services provided under the cost-plus drilling agreements are reported on a net basis. We entered into our second and third cost-plus drilling arrangements in September 2006 and August 2007 and commenced drilling immediately.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are generally completed within nine to twelve months after the commencement of drilling. We provide geological, engineering, and drilling supervision on the drilling and completion process and use subcontractors to perform drilling and completion services at a fixed footage-based rate and accordingly have the risk of loss in performing services under these arrangements. Accordingly, we report revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that the estimated total costs exceed the estimated total contract revenue. At December 31, 2007 and 2006, the loss contract reserve was $0.2 million and $0.3 million, respectively.

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

Accounting for Derivatives Contracts at Fair Value

We use derivative instruments to manage our commodity and financial market risks. We currently do not use hedge accounting treatment for our derivatives.

Derivatives are reported on our accompanying consolidated balance sheets at fair value on a gross asset and liability basis. Changes in fair value of derivatives are recorded in oil and gas price risk management, net, in our accompanying consolidated statements of income. The measurement of fair value is based on actively quoted market prices, if available. Otherwise, validation of a contract's fair value is performed internally and, while we use common industry practices to develop our valuation techniques, changes in our pricing methodologies or the underlying assumptions could result in significantly different fair values. If pricing information from external sources is not available, measurement involves our judgment and estimates. These estimates are based on valuation methodologies we consider appropriate. For individual contracts, the use of different assumptions could have a material effect on the contract's estimated fair value.

Oil and Gas Properties

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

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

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify our completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of the financial statements, the costs are expensed to exploration costs. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the well is classified as “suspended well costs” until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded. At December 31, 2007, suspended well costs included in oil and gas properties on our accompanying consolidated financial statements was $2.3 million.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved oil and gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to exploration expense. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms. The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we assess our oil and gas properties for possible impairment by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of oil and natural gas. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future net cash flows and an impairment of our oil and gas properties. Although our cash flow estimates are based on the relevant information available at the time the estimates are made, estimates of future cash flows are, by nature, highly uncertain and may very significantly from actual results.

Deferred Income Tax Asset Valuation Allowance

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

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

Accounting for Acquisitions Using Purchase Accounting

We account for acquisitions utilizing the purchase method as prescribed by SFAS No. 141, Business Combinations. Pursuant to purchase method accounting, the acquiring company must allocate the cost of the acquisition to assets acquired and liabilities assumed based on fair values as of the acquisition date. The purchase price allocations are based on appraisals, discounted cash flows, quoted market prices and estimates by management. In addition, when appropriate, we review comparable purchases and sales of oil and gas properties within the same regions, and use that data as a basis for fair market value; for example, the amount a willing buyer and seller would enter into an exchange for such properties. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed. In each of our acquisitions it was finally determined that the purchase price did not exceed the fair value of the net assets acquired. Therefore, no goodwill was ultimately recorded.

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

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

Recent Accounting Standards

See Note 1, Summary of Significant Accounting Policies - Recent Accounting Standards, to our accompanying consolidated financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK.

Market-Sensitive Instruments and Risk Management

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

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operation, Critical Accounting Policies and Estimates-Accounting for Derivatives Contracts at Fair Value, for further discussion of the accounting for derivative contracts.

Interest Rate Risk

We are exposed to risk resulting from changes in interest rates primarily as it relates to interest we earn on our cash, cash equivalents and designated cash and interest we pay on borrowings under our revolving credit facility. Interest-bearing cash and cash equivalents includes money market funds, short-term certificates of deposit and checking and savings accounts with various banks. The amount of interest-bearing cash and cash equivalents as of December 31, 2007, is $108.5 million with an average interest rate of 3.69%.

Based on a sensitivity analysis of the credit facility borrowings as of December 31, 2007, it was estimated that if market interest rates average 1% higher (lower) in 2008 than in 2007, interest expense, net of tax, would increase (decrease) by approximately $1.5 million. On February 8, 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018. This fixed-price debt transaction will lower our sensitivity to interest rate fluctuations.

Commodity Price Risk

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

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

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Economic Hedging Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2007, our oil and natural gas derivative instruments were comprised of futures, swaps and collars. These instruments generally consist of NYMEX-traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts for NECO production and CIG-based contracts for other Colorado production and NYMEX-based swaps for our Colorado and North Dakota oil production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.
- Collars contain a fixed floor price (put) and ceiling price (call). If the market price exceeds the call strike price or falls below the fixed put strike price, we receive the fixed price and pay the market price. If the market price is between the call and the put strike price, no payments are due from either party.

We purchase puts and set collars for our own and affiliate partnerships' production to protect against price declines in future periods while retaining much of the benefits of price increases. RNG enters into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market. We believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

The following table presents monthly average CIG and NYMEX closing prices for natural gas and oil in 2007 and 2006, as well as average sales prices we realized for the respective commodity.

	Year Ended December 31,	
	2007	2006
Average Index Closing Price Natural Gas (per MMbtu)		
CIG	$ 3.97	$ 5.63
NYMEX	6.89	7.23
Oil (per Barrel)		
NYMEX	69.79	64.73
Average Sales Price		
Natural Gas	5.33	5.91
Oil	60.65	59.33

Based on a sensitivity analysis as of December 31, 2007, it was estimated that a 10% increase in oil and natural gas prices over the entire period for which we have derivatives currently in place would have resulted in an increase in unrealized losses of $7.3 million and a 10% decrease in oil and natural gas prices would have resulted in a decrease in unrealized losses of $7.3 million.

See Note 1, Summary of Significant Accounting Policies, and Note 15, Derivative Financial Instruments, to our consolidated financial statements included in this report for additional disclosure regarding derivative instruments including, but not limited to, a summary of the open derivative option and purchase and sales contracts for us and RNG as of December 31, 2007.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. To reduce credit exposure, we seek to enter into netting agreements with counterparties that permit us to offset receivables and payables with such counterparties. We attempt to further reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. Where exposed to credit risk, we analyze the counterparties' financial condition prior to entering into an agreement, establish credit limits and monitor the appropriateness of those limits on an ongoing basis. There were no counterparty defaults during the years ended December 31, 2007, 2006 and 2005.

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Disclosure of Limitations

Because the information above included only those exposures that exist at December 31, 2007, it does not consider those exposures or positions which could arise after that date. As a result, our ultimate realized gain or loss with respect to interest rate and commodity price fluctuations will depend on the exposures that arise during the period, our hedging strategies at the time, and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

Index to financial statements.

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

Previous Independent Registered Public Accounting Firm

As previously reported on Form 8-K filed with the SEC on May 31, 2007, the Audit Committee of our Board of Directors recommended, and the Board of Directors ratified, the dismissal of KPMG LLP, or KPMG, as our principal accountants on May 24, 2007.

The audit reports of KPMG on our consolidated financial statements as of and for the years ended December 31, 2006 and 2005, contained no adverse opinion or disclaimer of opinion, nor were such reports qualified or modified as to uncertainty, audit scope or accounting principles, except as follows:

The audit report of KPMG on our consolidated financial statements as of December 31, 2006, and for the year then ended, dated May 22, 2007, indicated that, as described in Note 1, Summary of Significant Accounting Policies, to such consolidated financial statements, we adopted the provisions of Statement of Financial Accounting Standards No. 123(R), Share-Based Payment, and we changed our method of quantifying errors based on SEC Staff Accounting Bulletin No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements, in 2006.

The audit reports of KPMG on management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting as of December 31, 2006 and 2005, did not contain any adverse opinion or disclaimer of opinion, nor were they qualified or modified as to uncertainty, audit scope, or accounting principles, except that:

(1) KPMG's report as of December 31, 2006, includes an explanatory paragraph stating that “The Company acquired Unioil on December 6, 2006, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006, Unioil’s internal control over financial reporting associated with total assets of \$26.1 million and total revenues of \$0.3 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2006. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Unioil.”

(2) KPMG’s reports indicate that we did not maintain effective internal control over financial reporting as of December 31, 2006 and 2005, because of the effect of material weaknesses on the achievement of the objectives of the control criteria as described below:

Material Weaknesses as of December 31, 2006

- The Company did not have effective policies and procedures to ensure the timely reconciliation, review and adjustment of significant balance sheet and income statement accounts. As a result, material misstatements were identified during the Company's closing process in certain significant balance sheet and income statement accounts of the Company's 2006 consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

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- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise to ensure proper accounting for derivative instruments. Specifically, the Company's internal control processes did not ensure the completeness of all derivative contracts related to oil and gas sales, and also did not ensure the determination of the fair value of certain derivatives. As a result, misstatements were identified in the fair value of derivatives and related income statement accounts of the Company's 2006 consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures to ensure proper accounting for oil and gas properties. Specifically, the Company's review procedures were not sufficient to ensure that the calculations of depreciation and depletion were performed accurately and that the capitalization of costs was performed in accordance with the applicable authoritative accounting guidance. As a result, misstatements were identified in 2006 in depreciation, depletion and amortization expense of the Company's consolidated financial statements. This deficiency resulted in a more than remote likelihood that a material misstatement of the Company's annual or interim financial statements would not be prevented or detected.

Material Weaknesses as of December 31, 2005

We did not have effective policies and procedures, and were not adequately staffed with accounting personnel possessing an appropriate level of technical expertise in U.S. generally accepted accounting principles, as further described below:

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to properly account for derivative transactions in accordance with generally accepted accounting principles. Specifically, the Company's policies and procedures relating to derivatives transactions were not designed effectively to ensure that each of the requirements for hedge accounting was evaluated appropriately with respect to the Company's commodity based derivatives. Additionally, the Company's policies and procedures relating to the derivative transactions entered into on behalf of affiliated partnerships were not adequate to ensure these transactions were recorded properly in the financial statements. As a result, a misstatement was identified in the fair value of derivatives and the oil and gas price risk management loss accounts that was corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure compliance with appropriate accounting principles for its oil and gas properties. Specifically, the Company's policies and procedures were not designed effectively to ensure that the calculation of depreciation and depletion and the determintion of impairments were performed in accordance with the applicable authoritative accounting guidance. As a result, misstatements were identified in the accumulated depreciation, depletion and amortization and the depreciation, depletion and amortization expense accounts that was corrected prior to the issuance of the Company's 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure proper accounting and disclosure for income taxes. Specifically, the Company's policies and procedures did not provide for appropriate control documentation or supervisory review of permanent and temporary differences, or assessment of tax reserves to ensure that they were properly reflected and disclosed in the Company's financial statements. As a result, misstatements were identified in the deferred income tax liability and income tax expense accounts in the Company's preliminary 2005 consolidated financial statements. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

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- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to ensure that its accounting for asset retirement obligations complied with generally accepted accounting principles. Specifically, the Company's policies and procedures regarding the estimate of the fair value of the asset retirement obligations were not designed effectively to ensure that it was estimated in accordance with FAS No. 143, Asset Retirement Obligations. This deficiency results in more than a remote likelihood that a material misstatement of the Company's annual or interim consolidated financial statements would not be prevented or detected.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise, to provide for adequate monitoring and assessment of the application of accounting principles, standards or rules as it relates to proportionate consolidation in a timely manner. As a result of this control deficiency, the Company did not appropriately eliminate its proportionate share of transactions with the Company sponsored limited partnerships, which resulted in the restatement of the Company's financial statements for the first three quarters of 2005, the years ended December 31, 2004, 2003, 2002, and 2001 and each of the quarters in 2004 and 2003.

During the two years ended December 31, 2006, and the subsequent interim period through May 24, 2007, there were no: 1) disagreements with KPMG on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure that, if not resolved to KPMG’s satisfaction, would have caused KPMG to make reference to the subject matter of the disagreement in connection with its audit reports on our financial statements for such years, or 2) reportable events, except for the material weaknesses described above.

KPMG has been authorized to respond fully to the inquiries of the successor independent registered public accounting firm concerning the subject matter of the foregoing.

We provided KPMG with a copy of the foregoing statements and requested that KPMG furnish us with a letter addressed to the Securities and Exchange Commission stating whether KPMG agreed with the foregoing statements, and, if not, stating the respects in which KPMG did not agree. The letter from KPMG is attached as Exhibit 16 to our Form 8-K filed with the SEC on May 31, 2007.

New Independent Registered Public Accounting Firm

As previously reported on Form 8-K filed with the SEC on May 31, 2007, the Audit Committee of our Board of Directors recommended and the Board of Directors ratified the engagement of PricewaterhouseCoopers LLP, or PwC, as our independent registered public accounting firm the fiscal year ending December 31, 2007.

During our two most recent fiscal years ended December 31, 2006 and 2005, and through May 24, 2007, we did not consult with PwC regarding either (i) the application of accounting principles to a specified transaction, either completed or proposed, or the type of audit opinion that might be rendered on our financial statements, and neither a written report was provided to us nor oral advice was provided that PwC concluded was an important factor considered by us in reaching a decision as to any of the accounting, auditing or financial reporting issues; or (ii) any matter that was either the subject of a disagreement, as that term is defined in paragraph 304(a)(1)(iv) of Regulation S-K, or a reportable event required to be reported under paragraph 304(a)(1)(v) of Regulation S-K.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2007, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Securities Exchange Act Rule 13a-15(e). Based upon that evaluation, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were not effective as of December 31, 2007, to ensure that the information required to be disclosed by the Company in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC rules and forms, and that the information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to all timely decisions regarding required disclosure, due to the existence of material weaknesses described in Management's Report on Internal Control Over Financial Reporting included in Item 8 of this report.

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Changes in Internal Control over Financial Reporting

We have made the following changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Securities Exchange Act of 1934) during the quarter ended December 31, 2007, that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

- Installed new software supporting our derivative valuation process. The new system enhanced the existing internal controls framework over reporting more accurate information by automating a previously manual control.

During the third quarter of 2007, and continuing through the filing of this report, we made the following changes in our internal control over financial reporting that has materially affected, or is reasonably likely to materially affect our internal controls over financial reporting:

- Installed new software supporting our accounts payable process as part of a broader financial reporting system implementation. The new system enhanced the existing internal control framework over accounts payable and cash distribution process by automating several of the previously manual controls.

Additionally, during the first quarter of 2007, and continuing through the filing of this report, we implemented the following changes in internal control over financial reporting:

- Reinforced reconciliation procedures to ensure the timely reconciliation, review and adjustments to significant balance sheet and income statement accounts;
- Developed and approved extensive policies and procedures concerning the controls over financial reporting for derivatives;
- Provided additional training regarding derivatives for key personnel; and
- Developed a review process to ensure proper accounting for oil and gas properties, specifically the capitalization of costs and calculation of depreciation and depletion.

We continue to evaluate the ongoing effectiveness and sustainability of the changes we have made in internal control, and, as a result of the ongoing evaluation, may identify additional changes to improve internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information called for by Item 10 is incorporated by reference from information under the captions entitled Corporate Governance, Section 16(a) Beneficial Ownership Reporting Compliance, Election of Directors and Executive Compensation and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 11. EXECUTIVE COMPENSATION

The information called for by Item 11 is incorporated by reference from information under the caption entitled Executive Compensation and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

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

The information called for by Item 12 is incorporated by reference from information under the caption entitled Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and other relevant portions of our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

The information called for by Item 13 is incorporated by reference from information under the captions entitled Certain Relationships and Related Transactions and Director Independence in our definitive proxy statement to be filed pursuant to Regulation 14A no later than 120 days after the close of our fiscal year.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements:

See Index to Financial Statements and Schedules on page F-1.

(2) Financial Statement Schedules:

See Index to Financial Statements and Schedules on page F-1.

Schedules and Financial Statements Omitted

All other financial statement schedules are omitted because they are not required, inapplicable, or the information is included in the Financial Statements or Notes thereto.

(3) Exhibits:

See Exhibits Index on page 67.

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SIGNATURES

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

PETROLEUM DEVELOPMENT CORPORATION

By /s/ Steven R. Williams
Steven R. Williams,
Chairman and Chief Executive Officer

March 20, 2008

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

Signature	Title	Date
/s/ Steven R. Williams Steven R. Williams	Chairman, Chief Executive Officer and Director (principal executive officer)	March 20, 2008
/s/ Richard W. McCullough Richard W. McCullough	President, Chief Financial Officer and Director (principal financial officer)	March 20, 2008
/s/ Darwin L. Stump Darwin L. Stump	Chief Accounting Officer (principal accounting officer)	March 20, 2008
/s/ Daniel W. Amidon Daniel W. Amidon	General Counsel, Corporate Secretary	March 20, 2008
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	March 20, 2008
/s/ Vincent F. D'Annunzio Vincent F. D'Annunzio	Director	March 20, 2008
/s/ Kimberly Luff Wakim Kimberly Luff Wakim	Director	March 20, 2008
/s/ David C. Parke David C. Parke	Director	March 20, 2008
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	March 20, 2008
/s/ Joseph E. Casabona		

Joseph E. Casabona	Director	March 20, 2008
/s/ Larry F. Mazza Larry F. Mazza	Director	March 20, 2008

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GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this Form 10-K.

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

Bcf - One billion cubic feet.

Bcfe - One billion cubic feet of natural gas equivalents.

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

DD&A - Refers to depreciation, depletion and amortization of our property and equipment.

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

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

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

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

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

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

MBbls - One thousand barrels.

Mcf - One thousand cubic feet.

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

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

MMcf - One million cubic feet.

MMcfe - One million cubic feet of natural gas equivalents.

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

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

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

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

Oil - Crude oil or condensate.

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

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

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

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

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

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

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

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

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

Reserve replacement - Calculated by dividing the sum of reserve additions fro all sources (revisions, extensions, discoveries and other additions and acquisitions) by the actual production for the corresponding period. The values used for reserve additions are derived directly from the proved reserves table located in Note 20, Supplemental Oil and Gas information, to our consolidated financial statements included in this report. We use the reserve replacement ratio as an indicator of our ability to replenish annual production volumes and grow our reserves, thereby providing some information on the sources of future production. It should be noted that the reserve replacement ratio is a statistical indicator that has limitations. As an annual measure, the ratio limited because it typically varies widely based on the extent and timing of new discoveries and property acquisitions. Its predictive and comparative value is also limited for the same reasons. In addition, since the ratio does not imbed the cost or timing of future production of new reserves, it cannot be used as a measure of value creation.

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

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

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

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

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

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Exhibits Index

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Petroleum Development Corporation, filed herewith.
3.2	Bylaws of Petroleum Development Corporation, amended and restated effective October 11, 2007, incorporated by reference to Exhibit 3.2 to Form 8-K filed on October 17, 2007.
4.1	Rights Agreement by and between Petroleum Development Corporation and Transfer Online, Inc., as Rights Agent, dated as of September 11, 2007, including the forms of Rights Certificates and Summary of Stockholder Rights Plan attached thereto as Exhibits A and B, incorporated by reference to Exhibit 4.1 to Form 8-K filed September 14, 2007.
4.2	Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and The Bank of New York, incorporated by reference to Exhibit 4.1 to Form 8-K filed on February 12, 2008.
4.3	First Supplemental Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and the Bank of New York, incorporated by reference to Exhibit 4.2 to Form 8-K filed on February 12, 2008.
4.4	Form of 12% Senior Note due 2018, incorporated by reference to Exhibit 4.2 to Form 8-K filed on February 12, 2008.
10.1	Amended and Restated Credit Agreement, dated as of November 4, 2005, Petroleum Development Corporation, as borrower and JPMorgan Chase Bank, N.A and BNP Paribas, as lenders, incorporated by reference to Exhibit 10.2 to Form 8-K dated November 4, 2005.
10.2	First Amendment to Amended and Restated Credit Agreement, dated as of August 9, 2007, by an among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., BNP Paribas and Wachovia Bank, N.A., incorporated by reference to Exhibit 10.1 to Form 8-K filed August 15, 2007.
10.3	Second Amendment to Amended and Restated Credit Agreement, dated as of October 16, 2007, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., BNP Paribas, Wachovia Bank, N.A., Guaranty Bank, FSB, Bank of Oklahoma and Morgan Stanley Bank, incorporated by reference to Exhibit 10.1 to Form 8-K filed October 22, 2007.
10.4	Limited Consent and Waiver, Borrowing Base Increase and Aggregate Revolving Commitment Increase relating to the Amended and Restated Credit Agreement, dated as of November 21, 2007, by and among Petroleum Development Corporation, certain of its subsidiaries, JPMorgan Chase Bank, N.A., BNP Paribas, Wachovia Bank, N.A., Guaranty Bank, FSB, Bank of Oklahoma and Morgan Stanley Bank, incorporated by reference to Exhibit 10.1 to Form 8-K filed November 28, 2007.
10.5	Employment Agreement with Steven R. Williams, Chief Executive Officer and Chairman, dated as of March 7, 2003 and amended December 29, 2005, incorporated by reference in Exhibit 10.2 to Form 10-K filed on March 7, 2003 and Exhibit 99.1 to Form 8-K filed January 4, 2006.

10.6	Employment Agreement with Darwin L. Stump, Chief Accounting Officer, dated as of January 5, 2004 and amended December 29, 2005, incorporated by reference to Exhibit 99.4 Form 10-K dated January 5, 2004, and Exhibit 99.4 to Form 8-K filed January 4, 2006.
10.7	Employment Agreement with Thomas E. Riley, President, dated as of January 5, 2004, and amended December 29, 2005, incorporated by reference to Exhibit 99.6 Form 10-K dated January 5, 2004, and Exhibit 99.2 to Form 8-K filed January 4, 2006.
10.8	Employment Agreement with Eric R. Stearns, Executive Vice President, dated as of January 5, 2004, and amended December 29, 2005, incorporated by reference to Exhibit 99.5 Form 10-K dated January 5, 2004, and Exhibit 99.3 to Form 8-K filed January 4, 2006.

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10.9	Employment Agreement with Richard W. McCullough, Chief Financial Officer, dated as of November 13, 2006, incorporated by reference to Exhibit 10.6 to Form 10-K filed on May 23, 2007.
10.10	The Petroleum Development Corporation 401(k) & Profit Sharing Plan, incorporated by reference to Exhibit 4.1 to Form S-8, SEC File No. 333-137836.
10.11	2007 Compensation Arrangements with Executive Officers, incorporated by reference to Form 8-K dated February 20, 2007.
10.12	2007 Long-Term Incentive Program, incorporated by reference to Exhibit 10.1 to Form 8-K dated February 20, 2007
10.13	2007 Short-Term Incentive Program, incorporated by reference to Form 8-K dated April 2, 2007.
10.14	2005 Non-Employee Director Restricted Stock Plan, incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-126444 filed on July 7, 2005.
10.15	2004 Long-Term Equity Compensation Plan, incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-118215, filed on August 13, 2004.
10.16	Non-Employee Director Deferred Compensation Plan, incorporated by reference Exhibit 99.1 to Form S-8, SEC File No. 333-118222, filed on August 13, 2004.
10.17	1999 Incentive Stock Option and Non-Qualified Stock, incorporated by reference to Exhibit 99.1 to Form S-8, SEC File No. 333-111825, filed on January 9, 2004.
10.18	Indemnification Agreement with Directors and Officers, incorporated by reference to Exhibit 10.1 to Form 10-Q filed August 9, 2007.
10.19	2007 Long-Term Incentive Program, incorporated by reference to Exhibit 10.1 to Form 8-K filed on April 13, 2007.
10.20	2006 Long-Term Equity Compensation Grants to Executive Officers, incorporated by reference to Form 8-K filed on April 10, 2007.
10.21	Purchase and Sale Agreement by and between Petroleum Development Corporation and Marathon Oil Company dated July 20, 2006, incorporated by reference to Exhibit 10.1 to Form 10-Q filed on August 8, 2006.
10.22	Purchase and Sale Agreement between EXCO Resources, Inc., as Seller, and Petroleum Development Corporation, as Buyer, dated effective October 1, 2006, incorporated by reference to Exhibit 10.1 to Form 8-K filed on January 11, 2007.
10.23	Purchase Agreement dated as of February 1, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein, incorporated by reference to Exhibit 10.1 to Form 8-K filed on February 7, 2008
10.24	Registration Rights Agreement dated as of February 8, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein, incorporated by

	reference to Exhibit 10-1 to Form 8-K filed on February 12, 2008.
14.1	Code of Business Conduct and Ethics, incorporated by reference to Exhibit 3.1 to Form 10-K for the year ended December 31, 2002, SEC File No. 0-07246 filed on March 7, 2003.
21.1	Subsidiaries, filed herewith.
23.1	Consent of PricewaterhouseCoopers LLP, filed herewith.
23.2	Consent of KPMG LLP, filed herewith.
23.3	Consent of Wright & Company, Inc., Petroleum Consultants, filed herewith.
23.4	Consent of Ryder Scott Company, L.P., Petroleum Consultants, filed herewith.

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31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, filed herewith.
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002, filed herewith.

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PETROLEUM DEVELOPMENT CORPORATION

Index to Consolidated Financial Statements and Financial Statement Schedule

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PETROLEUM DEVELOPMENT CORPORATION

Management's Report on Internal Control Over Financial Reporting

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

Management has assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2007, based upon the criteria established in “Internal Control – Integrated Framework” issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). Based on this evaluation, management concluded that the Company did not maintain effective internal control over financial reporting as of December 31, 2007 because of the material weaknesses discussed below. A material weakness 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 the Company's annual or interim financial statements will not be prevented or detected on a timely basis. The Company’s assessment, as of December 31, 2007, identified the following material weaknesses:

- The Company did not maintain effective controls to ensure the completeness, accuracy, validity and restricted access of certain key financial statement spreadsheets that support all significant balance sheet and income statement accounts. Specifically, the Company has inadequate controls over: 1) the security and integrity of the data used in the various spreadsheets, 2) access to the spreadsheets, 3) changes to spreadsheet functionality and the related approval process and documentation, and 4) management's review of the spreadsheets. These spreadsheets are used in the financial close and reporting process to perform calculations, generate financial data supporting all significant processes and key manual controls, and to compile information to post entries into the general ledger system. This control deficiency resulted in an audit adjustment to the Company's consolidated financial statements for the year ended December 31, 2007. This control deficiency could result in a misstatement of any of our financial statement accounts and disclosures that would result in a material misstatement of the annual or interim financial statements that would not be prevented or detected in a timely manner.

- The Company did not have effective policies and procedures, or personnel with sufficient technical expertise to record derivative activities in accordance with generally accepted accounting principles. Specifically, the Company’s internal control processes did not ensure the completeness and accuracy of the derivative activities in the fourth quarter. The lack of documented policies and procedures, and the turnover in key personnel, including ineffective management review process, resulted in an audit adjustment to the Company's consolidated financial statements for the year ended December 31, 2007. This control deficiency could result in a misstatement of any of our derivative financial statement accounts and disclosures that would result in a material misstatement of the annual or interim financial statements that would not be prevented or detected in a timely manner.

The effectiveness of Petroleum Development Corporation's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

PETROLEUM DEVELOPMENT CORPORATION

/s/ Steven R. Williams
Steven R. Williams
Chairman and Chief Executive Officer

/s/ Richard W. McCullough
Richard W. McCullough
President and Chief Financial Officer

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PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders
of Petroleum Development Corporation

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Petroleum Development Corporation and its subsidiaries at December 31, 2007, and the results of their operations and their cash flows for the year then ended December 31, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company did not maintain, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) because material weaknesses in internal control over financial reporting related to spreadsheets used in the financial reporting process and accounting for derivative activities existed as of that date. A material weakness 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 the annual or interim financial statements will not be prevented or detected on a timely basis. The material weaknesses referred to above are described in the accompanying Management's Report on Internal Control Over Financial Reporting. We considered these material weaknesses in determining the nature, timing, and extent of audit tests applied in our audit of the 2007 consolidated financial statements, and our opinion regarding the effectiveness of the Company’s internal control over financial reporting does not affect our opinion on those consolidated financial statements. The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting included in management's report referred to above. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audit. We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

As discussed in Note 6 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions in 2007.

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

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

/s/ PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania
March 20, 2008

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PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Petroleum Development Corporation:

We have audited the accompanying consolidated balance sheet of Petroleum Development Corporation and subsidiaries as of December 31, 2006, and the related consolidated statements of income, shareholders' equity, and cash flows for each of the years in the two-year period ended December 31, 2006. In connection with our audits of the consolidated financial statements, we also have audited the related financial statement schedule. These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Petroleum Development Corporation and subsidiaries as of December 31, 2006, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2006, in conformity with U. S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R), (“Share-Based Payment”), in 2006.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of quantifying errors based on SEC Staff Accounting Bulletin No. 108 (“Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements”) in 2006.

KPMG LLP
Pittsburgh, Pennsylvania
May 22, 2007

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PETROLEUM DEVELOPMENT CORPORATION

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

December 31,	2007	2006
Assets		
Current assets:		
Cash and cash equivalents	$ 84,751	$ 194,326
Restricted cash - current	14,773	519
Accounts receivable, net	60,024	42,600
Accounts receivable - affiliates	11,537	9,235
Inventories	2,248	3,345
Fair value of derivatives	4,817	15,012
Other current assets	13,643	5,977
Total current assets	191,793	271,014
Properties and equipment, net	845,864	394,217
Restricted cash - long term	1,294	192,451
Goodwill	-	6,783
Other assets	11,528	19,822
Total Assets	$ 1,050,479	$ 884,287
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable	$ 88,502	$ 67,675
Accounts payable - affiliates	3,828	7,595
Short term debt	-	20,000
Production tax liability	21,330	11,497
Other accrued expenses	12,913	9,685
Deferred gain on sale of leaseholds	-	8,000
Federal and state income taxes payable	901	28,698
Fair value of derivatives	6,291	2,545
Advances for future drilling contracts	68,417	54,772
Funds held for distribution	39,823	31,367
Total current liabilities	242,005	241,834
Long-term debt	235,000	117,000
Deferred gain on sale of leaseholds	-	17,600
Other liabilities	19,968	19,400
Deferred income taxes	136,490	116,393
Asset retirement obligation	20,731	11,916
Total liabilities	654,194	524,143
Commitments and contingent liabilities		
Minority interest in consolidated limited liability company	759	-
Shareholders' equity:		
	149	148

Common shares, par value $.01 per share; authorized 50,000,000 shares; issued 14,907,679 in 2007 and 14,834,871 in 2006		
Additional paid-in capital	2,559	64
Retained earnings	393,044	360,102
Treasury shares at cost, 5,894 shares in 2007 and 4,706 in 2006	(226)	(170)
Total shareholders' equity	395,526	360,144
Total Liabilities and Shareholders' Equity	$ 1,050,479	$ 884,287

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Income
(in thousands, except per share data)

Year Ended December 31,	2007	2006	2005
Revenues:			
Oil and gas sales	$ 175,187	$ 115,189	$ 102,559
Sales from natural gas marketing activities	103,624	131,325	121,104
Oil and gas well drilling operations	12,154	17,917	99,963
Well operations and pipeline income	9,342	10,704	8,760
Oil and gas price risk management gain (loss), net	2,756	9,147	(9,368)
Other	2,172	2,221	2,180
Total revenues	305,235	286,503	325,198
Costs and expenses:			
Oil and gas production and well operations cost	49,264	29,021	20,400
Cost of natural gas marketing activities	100,584	130,150	119,644
Cost of oil and gas well drilling operations	2,508	12,617	88,185
Exploration expense	23,551	8,131	11,115
General and administrative expense	30,968	19,047	6,960
Depreciation, depletion, and amortization	70,844	33,735	21,116
Total costs and expenses	277,719	232,701	267,420
Gain on sale of leaseholds	33,291	328,000	7,669
Income from operations	60,807	381,802	65,447
Interest income	2,662	8,050	898
Interest expense	(9,279)	(2,443)	(217)
Income before income taxes	54,190	387,409	66,128
Provision for income taxes	20,981	149,637	24,676
Net income	$ 33,209	$ 237,772	$ 41,452
Basic earnings per common share	$ 2.25	$ 15.18	$ 2.53
Diluted earnings per common share	$ 2.24	$ 15.11	$ 2.52

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Shareholders' Equity
(in thousands, except per share data)

Year Ended December 31,	2007	2006	2005
Common stock, par value $.01 per share - shares issued:			
Shares at beginning of year	14,834,871	16,281,923	16,589,824
Adjust prior conversion of predecessor shares	-	59,546	-
Exercise of stock options	38,000	8,000	3,000
Issuance of stock awards, net of forfeitures	46,828	112,902	20,895
Retirement of treasury shares	(12,020)	(1,627,500)	(331,796)
Shares at end of year	14,907,679	14,834,871	16,281,923
Treasury stock:			
Shares at beginning of year	(4,706)	-	-
Purchase of treasury shares	(12,020)	(1,627,500)	(331,796)
Retirement of treasury shares	12,020	1,627,500	331,796
Non-employee directors' deferred compensation plan	(1,188)	(4,706)	-
Shares at end of year	(5,894)	(4,706)	-
Common shares outstanding	14,901,785	14,830,165	16,281,923
Common stock, $.01 par:			
Balance at beginning of year	$ 148	$ 163	$ 166
Exercise of stock options	-	-	-
Issuance of stock awards, net of forfeitures	1	1	-
Retirement of treasury shares	-	(16)	(3)
Balance at end of year	149	148	163
Additional paid-in capital:			
Balance at beginning of year	64	30,423	37,684
Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)	-	(825)	-
Exercise of stock options	183	31	12
Issuance of stock awards, net of forfeitures	(1)	(1)	-
Stock based compensation expense	2,286	1,516	603
Retirement of treasury shares	(646)	(31,150)	(7,876)
Excess tax benefit of stock based compensation	673	70	-
Balance at end of year	2,559	64	30,423
Retained earnings:			
Balance at beginning of year	360,102	158,504	117,052
Cumulative effect adjustment for the adoption of SAB 108, net of tax	-	(1,021)	-
FIN 48 adoption	(267)	-	-
Retirement of treasury shares	-	(35,153)	-
Net income	33,209	237,772	41,452
Balance at end of year	393,044	360,102	158,504
Unamortized stock award			
Balance at beginning of year	-	(825)	(882)
Issuance of stock awards	-	-	(603)
Amortization of stock awards	-	-	660

Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)	-	825	-
Balance at end of year	-	-	(825)
Treasury stock, at cost:			
Balance at beginning of year	(170)	-	-
Purchase of treasury shares	(646)	(66,319)	(7,879)
Retirement of treasury shares	646	66,319	7,879
Non-employee directors' deferred compensation plan	(56)	(170)	-
Balance at end of year	(226)	(170)	-
Total shareholders' equity	$ 395,526	$ 360,144	$ 188,265

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Cash Flows
(in thousands)

Year Ended December 31,	2007	2006	2005
Cash flows from operating activities:			
Net income	$ 33,209	$ 237,772	$ 41,452
Adjustments to net income to reconcile to net cash provided by operating activities:			
Deferred income taxes	12,201	86,431	3,351
Depreciation, depletion and amortization	70,844	33,735	21,116
Amortization of debt issuance costs	394	-	-
Impairment of oil and gas properties	1,485	1,519	-
Accretion of asset retirement obligation	999	515	465
Exploratory dry hole costs	1,775	1,790	11,115
Gain from sale of leaseholds	(33,291)	(328,000)	(7,669)
(Gain) loss from sale of assets	(31)	9	(207)
Expired and abandoned leases	1,786	2,169	48
Stock based compensation	2,286	1,516	660
Unrealized losses (gains) on derivative transactions	4,642	(7,620)	3,226
Excess tax benefits from stock-based compensation	(673)	(70)	-
Changes in current assets and liabilities:			
(Increase) decrease in restricted cash	(14,254)	982	(836)
(Increase) in accounts receivable	(16,456)	(9,935)	(11,811)
(Increase) in accounts receivable - affiliates	(2,302)	(194)	(5,319)
Decrease (increase) in inventories	1,285	1,987	(3,398)
Decrease (increase) in other current assets	4,839	(2,106)	3,482
Increase (decrease) in production tax liability	10,802	(261)	3,317
(Decrease) increase in accounts payable and accrued expenses	(10,869)	13,010	19,440
(Decrease) increase in accounts payable - affiliates	(3,099)	6,116	112
Increase in advances for future drilling contracts	13,645	4,773	7,502
(Decrease) increase in federal and state income taxes payable	(27,124)	19,950	8,473
Increase (decrease) in funds held for future distribution	7,488	(575)	18,505
Other	723	3,877	(652)
Net cash provided by operating activities	60,304	67,390	112,372
Cash flows from investing activities:			
Capital expenditures	(238,988)	(146,180)	(97,390)
Acquisition of oil and gas properties, net of cash acquired	(255,661)	(18,512)	-
Investment in drilling partnerships	-	(7,151)	(7,160)
Exploration costs	-	(765)	(1,918)
Decrease (increase) in restricted/designated cash	191,156	(192,416)	-
Proceeds from sale of leases to partnerships	1,371	1,798	2,829
Proceeds from sale of leaseholds/assets	34,701	353,600	9,597
Net cash used in investing activities	(267,421)	(9,626)	(94,042)
Cash flows from financing activities:			
Proceeds from debt	352,000	302,000	91,000

Proceeds from short-term debt	-	20,000	-
Payment of long-term debt	(254,000)	(209,000)	(88,000)
Payment of debt issuance costs	(1,468)	(160)	(423)
Proceeds from issuance of stock	183	31	12
Excess tax benefits from stock-based compensation	673	70	-
Minority interest investment	800	-	-
Purchase of treasury stock	(646)	(66,489)	(7,879)
Net cash provided by (used in) financing activities	97,542	46,452	(5,290)
Net (decrease) increase in cash and cash equivalents	(109,575)	104,216	13,040
Cash and cash equivalents, beginning of period	194,326	90,110	77,070
Cash and cash equivalents, end of period	$ 84,751	$ 194,326	$ 90,110

See accompanying Notes to Consolidated Financial Statements.
Supplemental Cash Flow information See Note 18.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

Petroleum Development Corporation ("PDC," "we," "us" or "the Company") is an independent energy company engaged primarily in the drilling and development, production and marketing of natural gas and oil. Since we began oil and gas operations in 1969, we have grown primarily through drilling and development activities, the acquisition of producing natural gas and oil wells and the expansion of our natural gas marketing activities. As of December 31, 2007, we operate approximately 4,354 wells located in the Appalachian Basin, Michigan Basin, and the Rocky Mountain Region. All of our oil and gas wells are located in West Virginia, Tennessee, Pennsylvania, Michigan, North Dakota, Colorado, Kansas, Texas and Wyoming. Our operations are divided into four business segments: oil and gas sales, natural gas marketing, oil and gas well drilling operations and well operations and pipeline income. See Note 17.

Principles of Consolidation

The consolidated financial statements of PDC include the accounts of our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. We account for our investment in interests in oil and gas limited partnerships under the proportionate consolidation method. Under this method, our consolidated financial statements include our investments in the partnerships recorded by our working interest in each well thereby accumulating our pro rata share of assets, liabilities and revenues and expenses respectively of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships is eliminated.

Cash Equivalents

For purposes of the statement of cash flows, we consider all highly liquid debt instruments with original maturities of three months or less to be cash equivalents.

Restricted and Designated Cash

In July 2006, we established a trust in the amount of $300 million with a qualified intermediary in conjunction with our sale of undeveloped leaseholds and corresponding "like-kind exchange" agreement. As of December 31, 2006, $300 million remained in the trust, with $109 million reflected in cash and cash equivalents as a current asset in our consolidated balance sheet and the remaining $191 million reflected as designated cash – property acquisitions, a non-current asset. The $191 million represented the amounts paid in January 2007 for the acquisition of oil and gas properties qualifying for "like-kind exchange" treatment. Interest earned on the trust account in 2006 of $5.5 million along with the $109 million not utilized for "like-kind exchange" purchases, is reflected in cash and cash equivalents, a current asset, at December 31, 2006, which was available to us for operating purposes in January 2007 and is no longer subject to a "like-kind exchange." We terminated the trust in January 2007 following the acquisitions of suitable like-kind properties, see Note 2.

In December 2006, we had paid a deposit of $0.5 million, reflected in our consolidated balance sheet as designated cash, a non-current asset, for the acquisition of oil and gas properties subsequently closed in January 2007.

In June 2007, we funded an escrow account in the amount of $14.1 million for amounts due to the limited partners of our sponsored drilling partnerships as a result of us over withholding estimated production taxes in years prior to 2007, which is included, along with interest earned of $0.4 million, in restricted cash, current, in our consolidated balance sheet as of December 31, 2007.

We are required to maintain margin deposits with brokers for outstanding derivative contracts. As of December 31, 2007 and 2006, cash in the amount of $0.3 million and $0.5 million, respectively, was on deposit and reflected in our consolidated balance sheets as restricted cash, a current asset.

We are required by various government agencies or joint venture agreements to maintain a bond or cash account for the plugging and abandonment of wells. As of December 31, 2007 and 2006, we had bonds in the form of certificates of deposit for plugging and abandonment of wells totaling $1.3 million and $1 million, respectively, which are reflected in restricted/designated cash, a non-current asset.

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Inventories

Materials, supplies and commodity inventories are stated at the lower of average cost or market and removed at carrying value.

Derivative Financial Instruments

We account for derivative financial instruments in accordance with Statement of Financial Accounting Standards ("SFAS") No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, as amended.

During 2007, 2006 and 2005, none of our derivative instruments qualified for use of hedge accounting under the terms of SFAS No. 133. Accordingly, we recognize all derivative instruments as either assets or liabilities on our consolidated balance sheets at fair value, and changes in the derivatives' fair values are recorded in our consolidated statements of income in oil and gas price risk management, net for our oil and gas commodities (derivatives related to our production only), in gas sales from marketing activities for RNG's gas sales, in cost of gas marketing activities for RNG's gas purchases. See Note 15.

In our consolidated balance sheets, we record the fair value of derivatives entered into on behalf of the affiliated partnerships and records an offsetting receivable from or payable to the partnerships. See Note 15.

Properties and Equipment

Oil and Gas Properties.

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

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

Exploration costs, including geological and geophysical expenses and delay rentals, are charged to expense as incurred. Exploratory well drilling costs, including the cost of stratigraphic test wells, are initially capitalized but charged to expense if the well is determined to be nonproductive. The status of each in-progress well is reviewed quarterly to determine the proper accounting treatment under the successful efforts method of accounting. Exploratory well costs continue to be capitalized as long as the well has found a sufficient quantity of reserves to justify our completion as a producing well and we are making sufficient progress assessing our reserves and economic and operating viability. If an in-progress exploratory well is found to be unsuccessful (referred to as a dry hole) prior to the issuance of the financial statements, the costs are expensed to exploration costs. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the well is classified as “suspended well costs” until we have had sufficient time to conduct additional completion or testing operations to evaluate the pertinent geological and engineering data obtained. At the time when we are able to make a final determination of a well’s productive status, the well is removed from the suspended well status and the proper accounting treatment is recorded. At December 31, 2007, suspended well costs included in oil and gas properties on our accompanying consolidated financial statements was $2.3 million. See Note 4.

The acquisition costs of unproved properties are capitalized when incurred, until such properties are transferred to proved properties or charged to expense when expired, impaired or amortized. Unproved oil and gas properties with individually significant acquisition costs are periodically assessed, and any impairment in value is charged to exploratory expense. The amount of impairment recognized on unproved properties which are not individually significant is determined by amortizing the costs of such properties within appropriate fields based on our historical experience, acquisition dates and average lease terms. In 2007, the aggregate impairment resulting from individually significant unproved properties and insignificant unproved properties was $1.5 million (which includes the liquidated damages of $1.1 million related to the abandonment of an exploration agreement with an unaffiliated party) and $1.8 million, respectively. In 2006, the impairment resulting from individually significant unproved properties and insignificant unproved properties was $0.5 million and $0.2 million, respectively. In 2005, impairment charges for individually significant and insignificant unproved properties were immaterial. These impairment costs are included in the statements of income as a component of exploration cost. The valuation of unproved properties is subjective and requires us to make estimates and assumptions which, with the passage of time, may prove to be materially different from actual realizable values.

In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, we assess our oil and gas properties for possible impairment quarterly by comparing net capitalized costs to estimated undiscounted future net cash flows on a field-by-field basis using estimated production based upon prices at which we reasonably estimate the commodity to be sold. The estimates of future prices may differ from current market prices of oil and natural gas. Any downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs could result in a reduction in undiscounted future net cash flows and an impairment of our oil and gas properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value which would consider future discounted cash flows. We recognized impairment losses on proved oil and gas properties of $1.5 million in 2006 in our Nesson Field in North Dakota, which is included in the statements of income as a component of exploration cost. No impairments were recorded in 2007 or 2005.

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

Other Property and Equipment.

Transportation Equipment, Pipelines and Other Equipment. Transportation equipment, pipelines and other equipment are carried at cost. Depreciation is provided principally on the straight-line method over the assets estimated useful lives. In accordance with SFAS No. 144, Accounting for the Impairment or Disposal of Long-Lived Assets, long-lived assets, such as property, plant and equipment, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds our estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds the fair value of the asset. No impairments were recorded in 2007, 2006, or 2005.

Maintenance and repairs are charged to expense as incurred. Major renewals and improvements are capitalized. Upon the sale or other disposition of assets, the cost and related accumulated depreciation, depletion and amortization are removed from the accounts, the proceeds are applied thereto and any resulting gain or loss is reflected in income.

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

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

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

Total depreciation expense related to other property and equipment was $4.3 million, $2 million and $2 million in 2007, 2006 and 2005, respectively.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Capitalized Interest

Interest costs are capitalized as part of the historical cost of acquiring assets. Oil and gas investments in unproved properties and major development projects, on which DD&A expense is not currently recorded and on which exploration or development activities are in progress, qualify for capitalization of interest. Major construction projects also qualify for interest capitalization until the asset is ready for service. Capitalized interest is calculated by multiplying our weighted-average interest rate on our debt by the qualifying costs. Interest capitalized may not exceed gross interest expense for the period. As the qualifying asset is moved to the DD&A pool, the related capitalized interest is also transferred and is amortized over the useful life of the asset. Interest costs of $3 million and $1.6 million were capitalized for the year 2007 and 2006, respectively. No interest costs were capitalized during 2005.

Production Tax Liability

Production tax liability represents estimated taxes, primarily severance and property, to be paid to the states and counties in which we produce oil and gas. Our share of these taxes is expensed to oil and gas production and well operations cost.

Advances for Future Drilling Contracts

Advances for future drilling contracts represent funds received from our sponsored drilling partnerships for drilling activities which have not been completed, a portion of which will be recognized as revenue in accordance with our revenue recognition policies.

Income Taxes

We account for income taxes under the asset and liability method. We recognize deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. If we determine that it is more likely than not that some portion or all of the deferred tax assets will not be realized, we record a valuation allowance thereby reducing the deferred tax assets to what we consider realizable. No valuation allowance was recorded at December 31, 2007 or 2006.

Asset Retirement Obligations

We account for asset retirement obligations by recording the fair value of our plugging and abandonment obligations when incurred, which is at the time the well is completely drilled. Upon initial recognition of an asset retirement obligation, we increase the carrying amount of the long-lived asset by the same amount as the liability. Over time, the liabilities are accreted for the change in their present value, through charges to oil and gas production and well operations costs. The initial capitalized costs are depleted over the useful lives of the related assets, through charges to depreciation, depletion and amortization. If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Revisions in estimated liabilities can result from revisions of estimated inflation rates, escalating retirement costs and changes in the estimated timing of settling asset retirement obligations. See Note 7 for a reconciliation of asset retirement obligation activity.

Minority Interest in Consolidated Limited Liability Company

In May 2007, we contributed $0.8 million for a 50% interest in WWWV, LLC ("LLC"), a limited liability company for which we serve as the managing member. One-sixth of the entity is owned by the Chief Executive Officer of our Company, who paid the same unit price for his interest as was paid by us and unrelated third parties for such interests in the LLC. The LLC's only asset is an aircraft and the LLC was formed for the purpose of owning and operating the aircraft.

The minority interest portion of pre-tax expense incurred by and belonging to the minority interest holders of the consolidated limited liability company is not material and included in our consolidated statement of income as an offset to DD&A expense.

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Retirement of Treasury Shares

We have historically retired all treasury share purchases, with the exception of shares purchased in accordance with our non-employee deferred compensation plan for non-employee directors, see Note 9. As treasury shares are retired, we charge any excess of cost over the par value entirely to additional paid-in-capital, to the extent we have amounts in paid-in-capital, with any remaining excess cost being charged to retained earnings.

Revenue Recognition

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

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

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

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

Oil and gas well drilling operations. Our drilling segment recognizes revenue from drilling contracts with sponsored drilling programs using the percentage of completion method based upon the percentage of contract costs incurred to date to the estimated total contract costs for each contract. We utilize this method since reasonably dependable estimates of the total estimated costs can be made and recognized revenues are subject to revisions as a contract progresses, the term of which can range from three to twelve months. In addition, we offer our drilling services under two types of contractual arrangements, cost-plus or footage-based service contracts, which result in differing risk and reward relationships, and consequently, different revenue reporting policies pursuant to Emerging Issues Task Force ("EITF") Issue No. 99-19, Reporting Revenue Gross as a Principal versus Net as an Agent.

The first cost-plus drilling service arrangement was entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Due to the fixed-fee-percentage nature of our revenues from these services, we have determined that, in substance, we are acting as an agent, without risk of loss during the performance of the drilling activities. Accordingly, our services provided under the cost-plus drilling agreements are reported on a net basis. We entered into our second and third cost-plus drilling arrangements in September 2006 and August 2007 and commenced drilling immediately.

Footage-based contracts provide for the drilling, completion and equipping of wells at footage rates and are generally completed within nine to twelve months after the commencement of drilling. We provide geological, engineering, and drilling supervision on the drilling and completion process and use subcontractors to perform drilling and completion services and accordingly has the risk of loss in performing services under these arrangements. Accordingly, we report revenue under these agreements gross of related expenses. Anticipated losses, if any, on uncompleted contracts are recorded at the time that the estimated total costs exceed the estimated total contract revenue. At December 31, 2007 and 2006, the loss contract reserve was $0.2 million and $0.3 million, respectively.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

Stock-Based Compensation

Effective January 1, 2006, we adopted SFAS No. 123R, Share-Based Payment (revised 2004). We elected the modified prospective method of adoption, and accordingly, prior period financial statements have not been restated. Pursuant to SFAS No. 123R we are required to recognize in our financial statements, based on fair value, compensation expense for all unvested stock options and other equity-based awards as of January 1, 2006. For all unvested options outstanding as of January 1, 2006 the previously measured but unrecognized compensation expense, based on the fair value at the original grant date, will be recognized in the financial statements over the remaining requisite service period for each separately vesting portion. For equity-based compensation awards granted or modified subsequent to January 1, 2006, compensation expense, based on the fair value on the date of grant or modification, will be recognized in the financial statements on a straight-line basis over the vesting period for the entire award. To the extent compensation cost relates to employees directly involved in oil and natural gas acquisition, exploration and development activities, such amounts are capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the appropriate cost and expense line item in the statement of income. For the year ended December 31, 2007 and 2006, we recognized stock-based compensation expense of \$2.3 million and \$1.5 million related to stock awards, respectively. Compensation capitalized as part of properties and equipment was immaterial in 2007 and 2006.

For periods prior to the adoption of SFAS No. 123(R), we accounted for our share-based compensation awards using the intrinsic value based method as prescribed by Accounting Principles Board Opinion ("APB") No. 25, Accounting for Stock Issued to Employees, and related interpretations. Under the intrinsic value based method, compensation expense for option awards was recorded on the date of grant only if the then-current market price of the underlying stock exceeded the exercise price. The following table illustrates the effect on net income and earnings per share had we applied the fair value recognition provisions of SFAS No. 123(R), as amended, to stock-based employee compensation during 2005 (in thousands, except per share data):

		Year ended December 31, 2005 (in thousands, except per share data)
Net income, as reported:	$	41,452
Stock-based compensation expense included in reported net income, net of tax		414
Total stock-based compensation expense determined under fair value method for all awards, net of tax		(509)
Pro forma net income	$	41,357
Earnings per share:		
Basic earnings per share, as reported and pro forma	$	2.53

Diluted earnings per share, as reported and pro forma	$	2.52

Earnings Per Share

Our basic earnings per share ("EPS") amounts have been computed based on the average number of shares of common stock outstanding for the period. Diluted EPS amounts include the effect of our outstanding stock options, unamortized portion of restricted stock and shares held pursuant to our non-employee director deferred compensation plan using the treasury stock method if including such potential shares of common stock is dilutive. See Note 12.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Use of Estimates

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

Fair Value of Financial Instruments

The carrying values of our receivables, payables and debt obligations approximate fair value as of December 31, 2007 and 2006, due to the short-term maturity of these instruments.

Recent Accounting Standards

Recently Adopted Accounting Standards

In December 2004, the Financial Accounting Standards Board ("FASB") issued SFAS No. 123(R), Share-Based Payment. In March 2005, the Securities and Exchange Commission ("SEC") issued Staff Accounting Bulletin ("SAB") No. 107, Share-Based Payment, regarding the interaction between SFAS No. 123(R) and certain SEC rules and regulations. Effective January 1, 2006, we adopted SFAS No. 123(R). We elected to use the modified prospective method for adoption, which requires compensation expense to be recognized in the statement of income for all unvested stock options and other equity-based compensation beginning in the first quarter of adoption. Prior to the adoption of SFAS No. 123(R), we followed the intrinsic value method in accordance with APB No. 25 (as amended) to account for employee stock-based compensation. The adoption of SFAS No. 123(R) required the unamortized stock award recorded under APB No. 25 related to stock-based compensation awards as of January 1, 2006, in the amount of $0.8 million to be eliminated against additional paid-in-capital. See Stock-Based Compensation policy above and Note 9 for further discussion of the Company's accounting for share-based compensation awards.

In September 2006, the SEC issued SAB No. 108, Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements. SAB No. 108 provides guidance on how the effects of prior year misstatements should be considered in quantifying misstatements in the current year financial statements. SAB No. 108 requires registrants to quantify misstatements using both the income statement ("rollover") and balance sheet ("iron curtain") approach and evaluate whether either approach results in a misstatement that, when all relevant quantitative and qualitative factors are considered, is material. Historically, we evaluated uncorrected misstatements using the "rollover" method which resulted in an accumulation of quantitatively and qualitatively immaterial misstatements to our consolidated financial statements. SAB No. 108 provides for a one time transitional adjustment to retained earnings for errors which were not deemed material to prior year financial statements, but which is material under guidance of SAB No. 108. We adopted SAB No. 108 during the fourth quarter of 2006 and recorded a one time adjustment to reduce retained earnings by $1.0 million.

In June 2006, the FASB issued EITF No. 06-3, How Taxes Collected from Customers and Remitted to Governmental Authorities Should be Presented in the Income Statement (That Is, Gross versus Net Presentation). EITF 06-3 addresses the income statement presentation of any tax collected from customers and remitted to a government authority and concludes that the presentation of taxes on either a gross basis or a net basis is an accounting policy decision that should be disclosed pursuant to APB No. 22, Disclosures of Accounting Policies. For taxes that are reported on a gross basis (included in revenues and costs), EITF 06-3 requires disclosure of the amounts of those taxes in interim and annual financial statements, if those amounts are significant. EITF 06-3 became effective for interim and annual reporting periods beginning after December 15, 2006. The adoption of the standard, effective January 1, 2007, did not have a significant effect on our consolidated financial statements. Our existing accounting policy, which was not changed upon the adoption of EITF 06-3, is to present taxes within the scope of EITF 06-3 on a net basis.

In July 2006, the FASB issued FASB Interpretation ("FIN") No. 48, Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement 109, which prescribes a comprehensive model for accounting for uncertainty in tax positions. FIN No. 48 provides that the tax effects from an uncertain tax position can be recognized in the financial statements, only if the position is more likely than not of being sustained on audit by the Internal Revenue Service ("IRS"), based on the technical merits of the position. The provisions of FIN No. 48 became effective for us on January 1, 2007. The cumulative effect of applying the provisions of FIN No. 48 has been accounted for as an adjustment to retained earnings in the first quarter of 2007. The adoption of FIN No. 48 resulted in a $0.3 million cumulative effect adjustment (see Note 6 for further discussion).

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In May 2007, the FASB issued FASB Staff Position FIN No. 48-1, Definition of Settlement in FASB Interpretation No. 48 ("FIN No. 48-1"). FIN No. 48-1 amends FIN No. 48 to provide guidance on how an entity should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The term "effectively settled" replaces the term "ultimately settled" when used to describe recognition, and the terms "settlement" or "settled" replace the terms "ultimate settlement" or "ultimately settled" when used to describe measurement of a tax position under FIN No. 48. FIN No. 48-1 clarifies that a tax position can be effectively settled upon the completion of an examination by a taxing authority without being legally extinguished. For tax positions considered effectively settled, an entity would recognize the full amount of tax benefit, even if the tax position is not considered more likely than not to be sustained based solely on the basis of its technical merits and the statute of limitations remains open. The adoption of FIN No. 48-1, effective January 1, 2007, did not have an incremental effect on our consolidated financial statements.

Recently Issued Accounting Standards

In September 2006, the FASB issued SFAS No. 157, Accounting for Fair Value Measurements. SFAS No. 157 defines fair value, establishes a framework for measuring fair value within generally accepted accounting principles and expands required disclosure about fair value measurements. SFAS No. 157 does not expand the use of fair value in any new circumstances. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007. However, on February 12, 2008, the FASB issued FASB Staff Position ("FSP") FAS 157-2, Effective Date of FASB Statement No. 157, which delayed the effective date of SFAS No. 157 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). This FSP partially defers the effective date of SFAS No. 157 to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years for items within the scope of this FSP. Effective January 1, 2008, we will adopt SFAS No. 157 except as it applies to those nonfinancial assets and nonfinancial liabilities as noted in FSP FAS 157-b. We are evaluating the effect that these new standards will have, if any, on our consolidated financial statements when adopted.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities. SFAS No. 159 permits entities to choose to measure, at fair value, many financial instruments and certain other items that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity's first fiscal year beginning after November 15, 2007. We are evaluating the effect that SFAS No. 159 will have, if any, in our consolidated financial statements when it is adopted in 2008.

In April 2007, the FASB issued FSP FIN No. 39-1, Amendment of FASB Interpretation No. 39 ("FIN No. 39-1'), to amend certain portions of Interpretation 39. FIN No. 39-1 replaces the terms "conditional contracts" and "exchange contracts" in Interpretation 39 with the term "derivative instruments" as defined in Statement 133. FIN No. 39-1 also amends Interpretation 39 to allow for the offsetting of fair value amounts for the right to reclaim cash collateral or receivable, or the obligation to return cash collateral or payable, arising from the same master netting arrangement as the derivative instruments. FIN No. 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. We are evaluating the effect that FIN No. 39-1 will have, if any, on our consolidated financial statements when adopted in 2008.

In December 2007, FASB issued SFAS No. 141 (revised 2007), Business Combinations ("SFAS No. 141R"), which replaces FASB Statement No. 141. SFAS No. 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. This statement also establishes disclosure requirements which will enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141R is effective as of the beginning of an entity's fiscal year beginning after December 15, 2008. We are evaluating the potential effect that the adoption of SFAS No. 141R will have, if any, on our consolidated financial statements when adopted in 2008.

In December 2007, the FASB issued SFAS No. 160, Non-controlling Interests in Consolidated Financial Statement—An Amendments of ARB No. 51 ("SFAS No. 160"). SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. Additionally, SFAS No. 160 establishes reporting requirements that provide sufficient disclosures which clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS No. 160 is effective as of the beginning of an entity's first fiscal year beginning after December 15, 2008. We are currently evaluating the potential effect that the adoption of SFAS No. 160 will have, if any, on our consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 2 – ACQUISITIONS

2007 Acquisitions

Acquisition of Internal Revenue Code Section 1031 – Like-Kind Exchange Properties

During the first quarter of 2007, we completed the acquisition of suitable like-kind properties in accordance with the like-kind exchange ("LKE") agreement we entered into in connection with our sale of undeveloped leaseholds located in Grand Valley Field, Garfield County, Colorado in July 2006. We acquired, for cash, qualifying oil and gas properties totaling $188.9 million, including costs of acquisition, as described below.

EXCO Properties. On January 5, 2007, we completed the purchase of producing properties and undeveloped drilling locations and acreage in the Wattenberg Field of the DJ Basin, Colorado from EXCO Resources Inc., an unaffiliated party. The acquisition included substantially all of EXCO's assets in the area and encompassed 144 oil and natural gas wells (approximating 25.5 Bcfe proved developed reserves as of December 31, 2005) and 8,160 acres of leasehold interests. The wells and leases acquired are located in Weld, Adams, Larimer, and Broomfield Counties, Colorado. We operate the assets and hold a majority working interest in the properties.

Company Sponsored Partnerships. On January 10, 2007, we completed the purchase of the remaining working interests in 44 of our sponsored partnerships. The transaction resulted in an increase in our ownership in 718 gross (423 net) wells that we currently operate. The wells are located primarily in the Appalachian Basin and Michigan.

The following table presents the adjusted purchase price for the like-kind exchange property acquisitions described above as of December 31, 2007.

	EXCO	Partnerships
	(in thousands)	
Cash consideration paid	$ 128,672	$ 57,776
Plus: direct costs of acquisition	1,662	1,664
Less: acquisition cost adjustments	(119)	(2,792)
Total acquisition cost	$ 130,215	$ 56,648

The following table presents, as of the respective date of acquisition, the final allocations of the purchase prices based on estimates of fair value.

	EXCO	Partnerships
	(in thousands)	

Current assets acquired	$ 91	$ -
Proved oil and gas properties	117,099	45,813
Unproved oil and gas properties	14,960	13,268
Asset retirement obligation	(422)	(2,433)
Other liabilities assumed	(1,513)	-
Preliminary acquisition cost	$ 130,215	$ 56,648

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

Other. In January 2007, we acquired from unaffiliated parties other like-kind undeveloped leaseholds in Erath County, Texas for $2.1 million, including costs of acquisition. Acreage in this area is prospective for development of oil and natural gas reserves in the Barnett Shale.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Other Acquisitions

On February 22, 2007, we acquired, from an unaffiliated party, 28 producing wells and associated undeveloped acreage located in Colorado (Wattenberg Field) for a purchase price of $12 million, which was allocated to oil and gas properties.

On October 30, 2007, with an effective date of October 1, 2007, we purchased from unrelated parties, Castle Gas Company, et.al., a majority working interest in 762 natural gas wells located in southwestern Pennsylvania for approximately $54 million. We estimated that the acquisition included approximately 47 Bcfe of reserves, or 31 Bcfe of proved reserves and 16 Bcfe of unproved reserves. The purchase also included associated pipelines, equipment, real estate and undeveloped acreage.

The following table presents the adjusted purchase price for the Castle acquisition described above as of December 31, 2007.

	(in thousands)	
Cash consideration paid	$	53,041
Plus: direct costs of acquisition		443
Plus: acquisition cost adjustments		583
Total acquisition cost	$	54,067

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

	(in thousands)	
Current assets acquired	$	185
Proved oil and gas properties		55,778
Unproved oil and gas properties		217
Real estate and equipment, and other assets		2,115
Non current assets		783
Asset retirement obligation		(4,043)
		(968)

Other liabilities assumed		
Preliminary acquisition cost	$	54,067

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

Pro Forma Financial Information

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

The following unaudited pro forma financial information presents a summary of our consolidated results of operations for the years ended December 31, 2007 and 2006, assuming the acquisitions of the EXCO properties, our sponsored partnerships and the Castle properties had been completed as of January 1, 2006, including adjustments to reflect the allocation of the purchase price to the acquired net assets. The pro forma effect of the inclusion of the results of operations for all of the other acquisitions described above, individually and in the aggregate, was not material.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(in thousands, except per share data)	
Total revenues	$ 310,351	$ 315,492
Net income	34,571	243,105
Earnings per common share:		
Basic	$ 2.34	$ 15.52
Diluted	$ 2.33	$ 15.44

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

2006 Acquisitions

On December 6, 2006, we completed our cash tender offer and purchased approximately 95.5% or 9,112,750 shares of the outstanding common stock of Unioil, an independent energy company with properties in northern Colorado and southern Wyoming. The acquisition of more than 90% of the outstanding shares of common stock allowed us to effect a short-form merger of Unioil and one of our wholly owned subsidiaries, resulting in the acquisition of the remaining 428,719 shares of Unioil. Each share of Unioil common stock not tendered through the offer was converted into the right to receive $1.91 in cash, the same consideration paid for shares in the tender offer. The total price paid for 100% of Unioil's outstanding common stock was $18.6 million, including $0.4 million in direct costs of the acquisition. The preliminary acquisition cost allocation included $6.8 million goodwill, in which was re-allocated to properties and equipment in the first quarter of 2007 as part of our process of finalizing the allocation of the preliminary purchase price. Further, as a result of this reclass, the deferred tax liabilities increased and thus increased property and equipment.

The following table presents the adjusted purchase price for the Unioil acquisition described above as of December 31, 2007.

	(in thousands)
Cash consideration paid	$ 18,224
Plus: direct costs of acquisition	382
Total acquisition cost	$ 18,606

The following table presents the final allocations of the purchase price based on estimates of fair value.

	(in thousands)
Current assets acquired	$ 660
Properties and equipment acquired	25,839
Deferred tax liability	(6,783)
Other liabilities assumed	(968)
Preliminary acquisition cost	$ 18,748

NOTE 3 – ACCOUNTS RECEIVABLE

Accounts receivable is presented on our consolidated balance sheets net of allowance for doubtful accounts. Accounts receivable are reviewed to determine which are doubtful of collection. In making the determination of the appropriate allowance for doubtful accounts, we consider our historical write-offs, relationships and overall credit worthiness of our customers, additional consideration is given to well production data for receivables related to well operations. The allowance as reflected in the accompanying balance sheets is our best estimate of the amount of probable credit losses in our existing accounts receivable. Our allowance for doubtful accounts as of December 31, 2007 and 2006, was $0.4 million and $0.4 million, respectively.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The nature of the independent oil and gas industry involves a concentration of oil and gas sales to a few customers. We sell oil and natural gas to various public utilities, gas marketers and industrial customers. The following table identifies significant customers as a percent of total oil and gas sales and total revenues for each of the years presented.

	Oil and Gas Sales Year Ended December 31,			Total Revenue Year Ended December 31,		
	2007	2006	2005	2007	2006	2005
Customer						
Tepco Crude Oil, LLC	14.8%	14.9%	10.5%	13.5%	12.9%	6.9%
Williams Production RMT Company	14.1%	8.7%	4.7%	12.9%	7.5%	3.1%
DCP Midstream, LP	7.8%	10.6%	10.6%	7.1%	9.1%	6.9%
Integrys (formerly WPS, Energy)	6.9%	9.4%	12.9%	6.3%	8.1%	8.4%
Sempra Energy Trading	6.0%	10.3%	15.2%	5.5%	8.9%	9.9%

NOTE 4 – PROPERTIES AND EQUIPMENT

	December 31, 2007	December 31, 2006
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	$ 953,904	$ 473,451
Unproved	41,023	27,055
Total oil and gas properties	994,927	500,506
Pipelines and related facilities	22,408	12,673
Transportation and other equipment	23,669	7,870
Land and buildings	11,303	11,620
Construction in progress(1)	2,929	4,801
	1,055,236	537,470
Accumulated depreciation, depletion and amortization ("DD&A")	(209,372)	(143,253)
	$ 845,864	$ 394,217

(1) At December 31, 2007, includes cost primarily related to a new integrated oil and gas financial software system.

Suspended Well Costs

The following table sets forth the capitalized exploratory well costs, which are pending the determination of proved reserves, included in oil and gas properties.

2007	2006	2005
	(in thousands)	

Beginning balance at January 1	$	765	$	1,918	$	4,170
Additions to capitalized exploratory well costs pending the determination of proved reserves		3,953		12,016		6,441
Reclassifications to wells, facilities and equipment based on the determination of proved reserves		(878)		(13,169)		(4,523)
Capitalized exploratory well costs charged to expense		(1,540)		-		(4,170)
Ending balance at December 31	$	2,300	$	765	$	1,918

As of December 31, 2007, the three wells awaiting the determination of proved reserves have not been capitalized for a period greater than one year.

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NOTE 5 - LONG-TERM DEBT

We have a credit facility with JPMorgan Chase Bank, N.A. ("JPMorgan") and BNP Paribas, as amended, dated as of November 4, 2005, with an activated commitment of $295 million as of December 31, 2007. The credit facility, through a series of amendments, includes commitments from Wachovia Bank, N.A., Bank of Oklahoma, Allied Irish Banks p.l.c., Guaranty Bank, BSB, Royal Bank of Canada and The Royal Bank of Scotland, plc. The maximum allowable commitment under the current credit facility is $400 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. We are required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate ("ABR") or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan's prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus 0.5%. ABR borrowings are assessed an additional margin spread up to 0.375% and adjusted LIBOR borrowings are assessed an additional margin spread of 1.125% to 1.875%, based upon the outstanding balance under the credit facility. The credit agreement requires, among other things, the maintenance of certain working capital and tangible net worth ratios. No principal payments are required until the credit agreement expires on November 4, 2010.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on our ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on our assets, (c) consolidate, merge or sell assets, (d) pay dividends and other distributions, (e) make certain investments, loans and advances, (f) enter into sale/leaseback transactions, (g) enter into transactions with our affiliates, (h) change the character of our business, (i) engage in hedging activities unless certain requirements are satisfied, (j) issue certain types of stock, and (k) make certain amendments to our organizational documents. The credit facility also requires us to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. In addition, we are required to comply with certain financial tests and maintain certain financial ratios. The financial tests and ratios include requirements to: (a) maintain a minimum ratio of consolidated current assets to consolidated current liabilities, or working capital ratio, and (b) not to exceed a maximum leverage ratio.

Effective August 9, 2007, the first amendment to our credit facility waived our working capital covenant until the earlier of (i) a debt or equity transaction resulting in net proceeds, as defined, to us of at least $200 million or (ii) July 1, 2008, which was further extended to October 1, 2008, effective October 16, 2007. In accordance with the first amendment, the ABR rate was increased by 0.375% as long as the waiver of the working capital covenant is in effect.

On February 8, 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018 for net proceeds received of approximately $196 million (see Note 19). In accordance with the senior credit agreement, upon the issuance of any senior notes, the borrowing base then in effect on our credit facility will automatically be reduced by $300 for each $1,000 in stated principal amount of such senior notes issued by us. Accordingly, effective February 8, 2008, our borrowing base under the credit facility was reduced from $295 million to $234.1 million. Further, our notes issuance meets the requirements of a debt transaction described above, and thus, the testing of our working capital covenant will resume with our quarter ending March 31, 2008.

The indenture governing our senior notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company.

As of December 31, 2007, the outstanding balance under our credit facility was $235 million compared to $117 million, excluding the overline note discussed below, as of December 31, 2006. The borrowing rate on the outstanding balance was 7.07% and 7.79% at December 31, 2007, and December 31, 2006, respectively. Amounts outstanding under the credit facility were secured by substantially all of our properties. We were in compliance with all covenants at December 31, 2007.

On December 19, 2006, we executed, pursuant to our credit facility, an overline note in the amount of $20 million to be repaid on January 31, 2007. Interest on the overline note accrued at a per annum rate equal to the alternate base rate plus 0.8% until December 22, 2006, at which time the rate converted to a Eurodollar borrowing for a one month period and at a per annum rate equal to an adjusted LIBOR rate plus 2.30%. The overline note was paid in full in accordance with its terms in January 2007.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 6 - INCOME TAXES

In both 2007 and 2006, we utilized our tax election to currently expense approximately $44 million and $55 million, respectively, of intangible drilling costs ("IDC"). This election substantially reduced our current tax expense but resulted in a correspondingly higher deferred tax expense as shown below. Additionally, in 2006, we had a substantial taxable gain from the sale of undeveloped oil and gas properties (see Note 16). We have chosen to use the favorable deferral aspects of the Internal Revenue Code ("IRC") Section 1031, LKE to defer the tax liability on a portion of the gain utilized by purchasing replacement properties (see Note 2). Accordingly, our current and deferred provision for income taxes increased proportionately in 2006 due to the current and deferred tax associated with this large taxable gain. The components of our tax expense consisted of the following:

	2007	2006 (in thousands)	2005
Current:			
Federal	$ 7,579	$ 54,467	$ 17,894
State	1,201	8,739	3,431
Total current income taxes	8,780	63,206	21,325
Deferred:			
Federal	11,074	74,003	2,834
State	1,127	12,428	517
Total deferred income taxes	12,201	86,431	3,351
Total income taxes	$ 20,981	$ 149,637	$ 24,676

Income tax expense differed from the amounts computed by applying the U.S. federal income tax rate of 35%.

	2007	2006 (in thousands)	2005
Computed "expected" tax	$ 18,966	$ 135,594	$ 23,145
State income tax (net)	1,907	13,744	2,566
Percentage depletion	(624)	(545)	(771)
Domestic production activities deduction	(374)	-	(399)
Other	1,106	844	135
	$ 20,981	$ 149,637	$ 24,676

In order to reduce current income taxes payable, we elected to expense, for income tax purposes, a large amount of IDC in 2007, our domestic production activities deduction, which in 2007 was statutorily equal to six percent of our qualified production activity income (QPAI), was $1.1 million. In 2006, due to our decision to expense $55 million of IDC, our domestic production deduction, which in 2006 was statutorily equal to three percent of QPAI, was zero. In addition, the amount in "Other" for 2007, was primarily nondeductible tax penalties.

The Internal Revenue Service ("IRS") examination of our federal tax returns for the 2003 and 2004 tax years was concluded on July 31, 2007. There was no significant affect on 2007 tax expense from the conclusion of this examination as most of the tax adjustments had been previously agreed to and accrued for at December 31, 2006. We have received notice from the IRS that they will be beginning the examination of our 2005 and 2006 returns in the near future.

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2007 and 2006, are presented below.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	2007	2006
	(in thousands)	
Deferred tax assets:		
Allowance for doubtful accounts	$ 138	$ 161
Drilling notes	31	46
Allowance for lease impairment	912	-
Litigation allowance	578	-
Deferred revenue related to cash withheld for future plugging cost	1,011	929
Deferred compensation	2,058	2,105
Asset retirement obligations	7,782	4,428
Unrealized loss - Derivatives	703	-
Employee benefits	456	798
Other	16	-
Total gross deferred tax assets	13,685	8,467
Less valuation allowance	-	-
Deferred tax assets	13,685	8,467
Deferred tax liabilities:		
Properties and equipment, principally due to differences in depreciation and amortization	(75,663)	(58,790)
Like kind exchange - deferred gain	(69,836)	(63,783)
Unrealized gains - derivatives	(55)	(1,203)
Total gross deferred tax liabilities	(145,554)	(123,776)
Net deferred tax liability	$ (131,869)	$ (115,309)
Classification in the Consolidated Balance Sheets:		
Net current deferred tax assets*	$ 4,621	$ 1,084
Net non-current deferred tax liability	(136,490)	(116,393)
Net deferred tax liability	$ (131,869)	$ (115,309)

*included in other current assets

As noted above, deferred tax liabilities for properties and equipment increased in 2007 and 2006 primarily as a result of our election to expense $44 million and $55 million of IDC for income tax purposes. Deferred tax liabilities also increased substantially in 2006 due to our utilization of the like-kind exchange tax deferral for a portion of the taxable gain on the undeveloped land sale (Note 16). In addition, approximately $9.8 million of the deferred liability for properties and equipment is due to the Unioil acquisition.

In assessing whether a valuation allowance for the deferred tax assets should be recorded, we consider whether it is more likely than not that some portion or all of the deferred tax assets will not be realized. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Based upon the level of historical taxable income and projections for future taxable income over the periods in which the deferred tax assets are deductible, we believe it is more likely than not that we will realize the benefits of these deductible differences. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.

We adopted the provisions of FIN No. 48 on January 1, 2007. As a result of adoption, retained earnings decreased by \$0.3 million, deferred income taxes payable decreased by \$0.9 million, current income taxes payable increased by \$0.2 million and the liability for unrecognized tax benefit increased by \$1.0 million.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table sets forth a reconciliation of the total amounts of unrecognized tax benefits for 2007:

		(in thousands)
Balance, January 1, 2007	$	952
Gross increases for tax positions of prior years		819
Gross decrease for tax positions of prior years		(883)
Settlements		-
Lapses of applicable statute of limitation		-
Unrecognized tax benefits at Balance, December 31, 2007	$	888

Interest and penalties related to uncertain tax positions are recognized in income tax expense. As of January 1, 2007, and December 31, 2007 we have approximately $0.3 million and $0.1 million of accrued interest related to uncertain tax positions, respectively. In addition, at December 31, 2007, $0.2 million of income tax penalties were accrued while no income tax penalties were accrued at January 1, 2007. The total amount of unrecognized tax benefits that would affect the effective tax rate, if recognized, is $0.4 million as of December 31, 2007 and zero as of January 1, 2007. We expect the unrecognized tax benefit at December 31, 2007, to decrease in the next twelve months because of the IRS examination of our 2005 and 2006 tax years that will be conducted in 2008. It is currently estimated that the decrease in our unrecognized tax benefits will be between $0.4 million and $0.9 million primarily due to settlements.

The statute of limitations for tax years 2003-2006 remains open for both federal and state taxing jurisdictions for the tax years 2003-2006. However, due to the recent July 31, 2007 completion date of the federal examination of our 2003 and 2004 tax years, we believe that certain tax positions related to these tax years have been “effectively settled” for federal tax purposes.

Our subsidiary, Unioil Inc., which was acquired on December 6, 2006, filed separate tax returns for years prior to the acquisition date. Unioil’s 2003-2006 tax returns remain open to examination at December 31, 2007. Any unrecognized tax benefit associated with Unioil's tax returns is included in the above table amount.

NOTE 7 - ASSET RETIREMENT OBLIGATIONS

Changes in carrying amounts of the asset retirement obligations associated with our working interest in oil and gas properties are as follows:

	2007	2006

(in thousands)

Balance at beginning of year	$ 11,966	$ 8,333
Obligations assumed with development activities and acquisitions	7,909	1,264
Obligations discharged with disposed properties and asset retirements	(93)	(115)
Accretion expense	999	515
Revisions to estimated cash flows	-	1,969
Balance at end of year	$ 20,781	$ 11,966

If the fair value of the estimated asset retirement obligation changes, an adjustment is recorded to both the asset retirement obligation and the asset retirement cost. Approximately $0.1 million of the asset retirement obligations were classified as short-term and included in other accrued expenses as of December 31, 2007 and 2006.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 8 - COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. We are a party to a pipeline expansion agreement with an unrelated third party, which is also currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to invest a minimum of $65 million to develop specified acreage in the Wattenberg Field, during a three-year period ending December 31, 2009. Such capital spending will include costs to drill new wells and the cost to recomplete existing wells in this area. Should we not meet the minimum commitment by December 31, 2009, we will be required to pay liquidated damages of $2 million, prorated based on our actual capital investment made to date. As of December 31, 2007, our total capital expenditures pursuant to the agreement were $27.5 million, resulting in a maximum potential obligation of $1.2 million.

In connection with the sale of undeveloped leaseholds in July 2006, we were obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per undrilled well for a total contingent obligation of $25.6 million, which was reflected as a deferred gain on sale of leaseholds in our consolidated balance sheet at December 31, 2006. On May 31, 2007, we entered into a letter agreement amending the original purchase and sale agreement. The letter agreement relieved us of the obligation, in its entirety, to either drill 16 wells or pay liquidated damages, resulting in the recognition of the remaining $25.6 million deferred gain on sale of leaseholds in the quarter ended June 30, 2007.

Pursuant to the above letter agreement, we are obligated to drill six wells on specifically identified acreage. These wells will be drilled on the unaffiliated party's leasehold for its benefit and at its cost. In addition, the unaffiliated party will return 160 acres of leasehold property acquired from us pursuant to the purchase and sale agreement. As of the date of this report, we have drilled the six wells and received the 160 acres of leasehold property.

In connection with the acquisition of oil and gas properties in October 2007, we are obligated to drill 100 wells in the Appalachian Basin by January 2016. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of $25,000 per undrilled well for a total contingent obligation of $2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of December 31, 2007, no wells had been drilled pursuant to this agreement.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months' cash distributions), if repurchase is requested by investors, and subject to our financial ability to do so. The maximum annual repurchase obligation as of December 31, 2007, was approximately $6.7 million. We have adequate liquidity to meet this obligation. During 2007 and 2006, we paid $1.6 million and $0.8 million, respectively, under this provision for the repurchase of partnership units. As of December 31, 2007, outstanding repurchase offers to investing partners totaled $0.5 million, principally all of which were consummated in 2008 prior to expiration.

Performance Supplements. Our drilling programs formed from 1996 through the second quarter of 2005 contain a performance supplement that provides for changes in the distribution of partnership profits if certain levels of performance are not met. The terms of this provision in the partnership agreements are not a guarantee of a rate of return on an investment in the partnership. Under those specific conditions, such changes can result in our share of an affected partnership’s profits being reduced by up to one half of the amount to which we otherwise would be entitled in the affected period. In no event would we be obligated to assume a disproportionate share of losses in such partnerships; should the partnerships which contain this provision in the partnership agreements incur a loss, our share of such losses would be unaffected by the terms of this provision. In accordance with these provisions, our share of partnership profits was reduced by an aggregate of $0.6 million, $1 million and $0.7 million during 2007, 2006 and 2005, respectively. As of December 31, 2007 and 2006, based on production through December 31 of the corresponding year, we had accrued $0.2 million and $0.4 million, respectively.

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Drilling Rig Contracts. In order to secure the services for drilling rigs, we made commitments to the drilling contractors, which call for a minimum commitment of $12,500 daily for a specified amount of time if we cease to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $40,680 daily for a specified amount of time for daily use of the drilling rigs. As of December 31, 2007, commitments for these two separate contracts expire in August 2009 and July 2010. As of December 31, 2007, we have an outstanding minimum commitment for $6.4 million and an outstanding maximum commitment for $24.7 million.

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

On May 29, 2007, Glen Droegemueller, individually and as representative plaintiff on behalf of all others similarly situated, filed a class action complaint against the Company in the District Court, Weld County, Colorado alleging that we underpaid royalties on natural gas produced from wells operated by us in the State of Colorado (the "Droegemueller Action"). The plaintiff seeks declaratory relief and to recover an unspecified amount of compensation for underpayment of royalties paid by us pursuant to leases. We removed the case to Federal Court on June 28, 2007, and on July 10, 2007, we filed its answer and affirmative defenses. A second similar Colorado class action suit was filed against the Company in the U.S. District Court for the District of Colorado on December 3, 2007, by Ted Amsbaugh et al. On December 31, 2007, plaintiff in this second action filed a motion to consolidate the case with the Droegemueller Action above. On January 28, 2008, the Court granted plaintiff's motion to consolidate the action with the Droegemueller Action. On February 29, 2008, the court approved a 90 day stay in proceedings while the parties pursue mediation of the matter. Given the preliminary stage of this proceeding and the inherent uncertainty in litigation, we are unable to predict the ultimate outcome of this suit at this time. We believe that the ultimate outcome of the proceedings will not have a material adverse effect on our financial condition or results of operations.

Litigation similar to the preceding actions has recently been commenced against several other companies in other jurisdictions where we conduct business. While our business model differs from that of the parties involved in such other litigation, and although the Company has not been named as a party in such other litigation, there can be no assurance that the Company will not be named as a party to such other litigation in the future.

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

In the event of termination without cause or if an executive officer terminates employment for good reason, the executive officer is entitled to receive a payment in the amount of three times the sum of his highest base salary during the previous two years of employment immediately preceding the termination date and his highest bonus received during the same two year period. The executive officer is also entitled to (i) vesting of any unvested equity compensation, (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of any earned and unpaid bonus amounts. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitle to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated. See Note 19 for a discussion regarding the departure of our President for good reason.

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

In the event that an executive officer voluntarily terminates his employment for other than good reason, he is entitled to receive (i) his base salary, bonus and incremental retirement payment prorated for the portion of the year that the executive officer is employed, (ii) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted or in full without discount within 60 days of the termination date at our discretion, (iii) any unpaid expense reimbursement upon presentation by the executive officer of an accounting of such expenses in accordance with our normal practices, and (iv) any other payments for benefits earned under the employment agreement or our plans.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Derivative Contracts. We would be exposed to oil and natural gas price fluctuations on underlying purchase and sale contracts should the counterparties to our derivative instruments or the counterparties to our gas marketing contracts not perform. Nonperformance is not anticipated. There were no counterparty default losses in 2007, 2006 or 2005.

NOTE 9 - COMMON STOCK

Stock-Based Compensation Plans

As approved by the shareholders in June 2004, we maintain a long-term equity compensation plan for officers and certain key employees of (the "2004 Plan"). In accordance with the plan, awards may be issued in the form of stock options, stock appreciation rights, restricted stock or performance shares. A total of 750,000 new shares of common stock have been reserved for issuance. Awards pursuant to the plan vest over periods set at the discretion of the Compensation Committee of our Board of Directors ("Board") and have a maximum exercisable period of ten years. As of December 31, 2007, 468,984 common shares remain available for future awards.

As approved by the shareholders in June 2005, we also maintain a restricted stock plan for non-employee directors. A total of 40,000 new shares of common stock have been reserved for issuance under the plan. During 2007, 2006 and 2005, 12,710, 6,551 and 6,895 common shares, respectively, were awarded in accordance with the plan. Compensation expense for each of the years ended December 31, 2007, 2006 and 2005, related to these restricted shares was $0.2 million, $0.1 million and $0.1 million, respectively. As of December 31, 2007, 13,844 common shares remain available for future awards.

In August 1999, the shareholders approved the 1999 Incentive Stock Option and Non-Qualified Stock Option Plan. A total of 500,000 shares of our common stock were reserved for issuance upon the exercise of stock options. All shares authorized to be awarded pursuant to this plan were awarded in years prior to 2002. At December 31, 2007, options for 11,000 common shares remain outstanding and exercisable through 2011, at which time the options will expire.

The following table provides a summary of the effect of our stock based compensation plans on the results of operations for the periods presented. Prior to the adoption of SFAS No. 123R, we did not recognize stock based compensation expense in our financial statements.

	Year Ended December 31,	
	2007	2006
	(in thousands)	
Total stock based compensation expense	$ 2,286	$ 1,516
Income tax benefit	(882)	(585)
Net income impact	$ 1,404	$ 931

Stock Option Awards. We granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. We did not grant any stock option awards in 2007 or 2006. The fair values of stock options granted during the year ended December 31, 2006, were estimated at the date of grant using a Black-Scholes option-pricing model assuming no dividends and the following weighed average assumptions:

	2006
Expected volatility	40.4%
Expected term (in years)	6.0
Risk-free interest rate	4.2%
Weighted-average grant date fair value per share	$ 20.30

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Expected volatilities are based on our historical volatility. The expected life of an award is estimated using historical exercise behavior data. The risk-free interest rate is based on the U.S. Treasury yields in effect at the time of grant and extrapolated to approximate the expected life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

The following table provides a summary of our stock option award activity for the year ended December 31, 2007:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (years)
Outstanding at December 31, 2006	89,567	$ 21.36	5.6
Exercised	(38,000)	4.81	
Outstanding at December 31, 2007	51,567	33.55	6.4
Vested and expected to vest at December 31, 2007	46,340	32.51	6.2
Exercisable at December 31, 2007	29,582	26.30	5.1

	Year Ended December 31,		
(in millions)	2007	2006	2005
Total intrinsic value of options exercised	$ 1.7	$ 0.3	$ 0.1
Total intrinsic value of options outstanding	1.3	2.0	1.6
Total intrinsic value of options exercisable	1.0	1.9	1.6

The intrinsic value of options exercised represents the amount by which the market value of our stock at date of exercise exceeds the exercise price of the option. The intrinsic values of the options outstanding and exercisable represent the amount by which the closing market price of our common stock at the last trading day of the year exceeds the exercise price of the options.

Total unrecognized compensation cost related to stock options granted under the 2004 Plan was $0.2 million as of December 31, 2007. This cost is expected to be recognized over a weighted average period of 2.2 years.

Restricted Stock Awards

We began issuing shares of restricted common stock to employees in 2004. Our restricted stock awards have been awarded with vesting conditions that are either time-based or market-based.

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, primarily over four years.

The following table sets forth the changes in non-vested time-based awards for the year ended December 31, 2007:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2006	131,730	$ 39.87
Granted	79,595	48.09
Vested	(37,341)	36.63
Forfeited	(2,139)	40.07
Non-vested at December 31, 2007	171,845	$ 44.38

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	Year Ended December 31,		
(in millions)	2007	2006	2005
Total intrinsic value of time-based awards vested	$ 2.2	$ 0.8	$ 0.2
Total intrinsic value of time-based awards non-vested	10.2	5.7	1.3

The intrinsic value above is based upon the closing market price of our common stock on the last trading date of the year, $59.13.

The total compensation cost related to non-vested time-based awards not yet recognized as of December 31, 2007, is $5.3 million. This cost is expected to be recognized over a weighted-average period of 2.7 years.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years for market-based awards. The market-based shares vest only upon the achievement of certain per share price thresholds and continuous employment during the vesting period. All compensation cost related to the market based-awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

The weighted average grant date fair value of each market-based share was computed using the Monte Carlo pricing model and the following weighted average assumptions:

Expected term of award	3 years
Risk-free interest rate	4.7%
Volatility	44.0%

The following table sets forth the changes in non-vested marked-based awards for the year ended December 31, 2007:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2006	-	$ -
Granted	31,972	36.07
Vested	-	-
Forfeited	-	-
Non-vested at December 31, 2007	31,972	$ 36.07

The intrinsic value of market-based awards outstanding at December 31, 2007, was $1.9 million, based upon the closing market price of our common stock on the last trading date of the year, $59.13.

The total compensation cost related to non-vested market-based awards not yet recognized as of December 31, 2007, is $0.4 million. This cost is expected to be recognized over a weighted-average period of 2 years.

Treasury Share Purchases

In January 2006, we announced that our Board authorized the purchase of up to 10% (1,627,500 shares) of our common stock during 2006. Stock purchases under this program were made in the open market or in private transactions, at times and in amounts that we deemed appropriate. In October 2006, we completed our January 2006 program. Total shares purchased pursuant to the program were 1,627,500 common shares at a cost of $66.3 million ($40.75 average price paid per share), including 100,000 shares from one of our executive officers at a cost of $4.1 million ($40.66 price paid per share). All shares purchased in accordance with the program have subsequently been retired.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

On October 16, 2006, our board of directors of approved a second 2006 purchase program authorizing us to purchase up to 10% (1,477,109 shares) of our then outstanding common stock through April 2008. Stock purchases under this program may be made in the open market or in private transactions, at times and in amounts that we deem appropriate. Shares are generally purchased at fair market value based on the closing price on the date of purchase. Total shares purchased in 2007 pursuant to the program were 12,020 common shares at a cost of $0.6 million ($53.78 average price paid per share), including 5,187 shares from our executive officers at a cost of $0.3 million ($57.93 price paid per share). Shares purchased pursuant to the plan were primarily to satisfy the statutory minimum tax withholding requirement for restricted stock that vested in 2007. All shares were subsequently retired.

Pursuant to our senior notes indenture entered on February 8, 2008, any future purchases are limited, see Note 19, Subsequent Events, to our accompanying consolidated financial statements.

On February 25, 2008, pursuant to a separation agreement, we purchased 50,000 shares of our common stock from one of our executive officers at a cost of $3.4 million, or $67.92 per share. See Note 19, Subsequent Events, to our consolidated financial statements

NOTE 10 - SHAREHOLDERS' RIGHTS AGREEMENT

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

NOTE 11 - EMPLOYEE BENEFIT PLANS

We sponsor a qualified deferred compensation plan covering substantially all of our employees. The plan consists of a 401(k) retirement plan with a profit sharing component. The plan enables eligible employees to contribute a portion of their compensation through payroll deductions in accordance with specific guidelines. We provide a discretionary matching contribution based on a percentage of the employees' contributions up to certain limits. Our contribution to the profit sharing component is discretionary. Our total combined expense for to both 401(k) and profit sharing in 2007, 2006 and 2005, were $1.4 million, $3.1 million and $0.9 million, respectively.

We provide a supplemental retirement benefit of deferred compensation under terms of the various employment agreements with certain executive officers. During 2007, 2006 and 2005, we charged $0.4 million, $0.3 million and $0.2 million related to this plan to general and administrative expenses, respectively, and we have recorded a related liability in the amount $2.2 million and $1.9 million as of December 31, 2007 and 2006, respectively.

In addition to the supplemental retirement benefit of deferred compensation, we offer a supplemental healthcare benefit covering certain executive officers and their spouses in accordance with each officer's employment agreement. Expense incurred during 2007 related to this plan was immaterial. As of December 31, 2007, we had a recorded liability of $0.6 million.

We maintain a non-qualified deferred compensation plan for our non-employee directors. The amount of compensation deferred by each participant is based on participant elections. The amounts deferred pursuant to the plan are invested in our common stock, maintained in a rabbi trust and are classified in the accompanying balance sheet as treasury shares as a component of shareholders' equity. The plan may be settled in either cash or shares as requested by the participant. As of December 31, 2007, we had recorded a long-term liability of $0.3 million, which is included in other liabilities in our consolidated balance sheet.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 12 - EARNINGS PER SHARE

The following is a reconciliation of the numerators and denominators used in the calculation of basic and diluted earnings per share for the years ended December 31:

	2007	2006	2005
	(in thousands, except per share data)		
Weighted average common shares outstanding	14,744	15,660	16,362
Dilutive effect of share-based compensation: (1)			
Unamortized portion of restricted stock	44	22	13
Stock options	48	55	52
Non employee director deferred compensation	5	4	-
Weighted average common and common equivalent shares outstanding	14,841	15,741	16,427
Net income	$ 33,209	$ 237,772	$ 41,452
Basic earnings per common share	$ 2.25	$ 15.18	$ 2.53
Diluted earnings per common share	$ 2.24	$ 15.11	$ 2.52

(1) Excludes the effect of average anti-dilutive common share equivalents related to out-of-the-money options and unvested restricted shares of zero and 18,004 in 2007, 23,687 and zero in 2006 and 16,880 and zero in 2005, respectively.

NOTE 13 - TRANSACTIONS WITH AFFILIATES

Funds held for future distribution on our consolidated balance sheets represent amounts owed to affiliated partnerships for production proceeds received by us on their behalf and undistributed as of December 31, 2007 and 2006.

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

Our natural gas marketing segment manages the marketing of oil and natural gas for our affiliated partnerships in the Appalachian Basin. Our sales from of natural gas marketing activities includes $9.3 million, $17.6 million and $22.2 million in 2007, 2006 and 2005, respectively, related to the marketing of oil and natural gas on behalf of our affiliated partnerships. Included in our cost of natural gas marketing activities is $9.1 million, $17.3 million and $22.2 million for 2007, 2006 and 2005, respectively, related to these sales.

We provided oil and gas well drilling services to our affiliated partnerships. Pursuant to our cost-plus drilling arrangements and our corresponding net presentation, we performed drilling services for our affiliated partnerships totaling $68.4 million and $87 million in 2007 and 2006, for which we recognized $11.4 million and $12.4 million in oil and gas well drilling operations revenue, respectively. Pursuant to our footage-based drilling arrangements and our corresponding gross presentation, in 2005, we billed our affiliated partnerships for drilling services and recognized oil and gas well drilling operations revenue of $100 million. Further, we provide well operations and pipeline services to our affiliated partnerships. Substantially all of our revenue and expenses related to oil and gas well drilling operations and revenues from well operations and pipeline income are associated with services provided to our affiliated partnerships.

Revenues from oil and gas well drilling operations and costs of oil and gas well drilling operations each include $0.1 million and $0.2 million during 2006 and 2005, respectively, related to investments made by executive officers for working interests in wells drilled during the respective years. Amounts invested by the executive officers during 2007 were immaterial.

Management fees collected from the affiliated partnerships amounted to $1.3 million in 2007 and 2006 and $1.7 million in 2005, respectively, which are included in other income on our consolidated statements of income.

Through our wholly-owned subsidiary, PDC Securities Incorporated, we act as Dealer-Manager of the drilling partnerships. PDC Securities receives the applicable commissions and marketing allowances from the Escrow Agent of the drilling program and distributes them to the soliciting broker/dealers who sell the programs. The commissions and marketing allowances received by PDC Securities are included in other income net of the commissions distributed to the soliciting broker/dealer. The commissions and marketing allowances retained by PDC Securities were $0.5 million, $0.6 million and $0.5 million and those distributed to the soliciting broker/dealers amounted to $8.3 million, $8.8 million and $11.4 million for the years ended December 31, 2007, 2006 and 2005, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 14 - LEASE OBLIGATIONS

We have entered into operating leases principally for the leasing of natural gas compressors, our Denver office space, and general office equipment. The future minimum lease payments under these non-cancelable operating leases as of December 31, 2007, are as follows:

Year	(in thousands)
2008	$ 1,850
2009	1,131
2010	534
2011	430
2012	92
Thereafter	-
	$ 4,037

Lease operating expense for the years ended December 31, 2007, 2006 and 2005 was $1.5 million, $0.4 million and $0.3 million, respectively.

NOTE 15 – DERIVATIVE FINANCIAL INSTRUMENTS

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

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

Economic Hedging Strategies. Our results of operations and operating cash flows are affected by changes in market prices for oil and natural gas. To mitigate a portion of the exposure to adverse market changes, we have entered into various derivative instruments. As of December 31, 2007, our oil and natural gas derivative instruments were comprised of futures, swaps and collars. These instruments generally consist of New York Mercantile Exchange ("NYMEX") -traded natural gas futures contracts and option contracts for Appalachian and Michigan production, Panhandle-based contracts and NYMEX-traded contracts for NECO production and Colorado Interstate Gas Index ("CIG") -based contracts for other Colorado production and NYMEX-based swaps for our Colorado and North Dakota oil production.

- For swap instruments, we receive a fixed price for the hedged commodity and pay a floating market price to the counterparty. The fixed-price payment and the floating-price payment are netted, resulting in a net amount due to or from the counterparty.

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

We purchase puts and set collars and swaps for our own and affiliate partnerships' production to protect against price declines in future periods while retaining much of the benefits of price increases. RNG enters into fixed-price physical purchase and sale agreements that are derivative contracts. In order to offset these fixed-price physical derivatives, we enter into financial derivative instruments that have the effect of locking in the prices we will receive or pay for the same volumes and period, offsetting the physical derivative. While these derivatives are structured to reduce our exposure to changes in price associated with the derivative commodity, they also limit the benefit we might otherwise have received from price changes in the physical market. We believe our derivative instruments continue to be highly effective in achieving the risk management objectives for which they were intended.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The net fair value of the commodity based derivatives was $(1.4) million of which $0.2 million is included in other long term assets at December 31, 2007. The net fair value of the commodity based derivatives was $13.6 million of which $1.1 million is included in other long term assets at December 31, 2006. We recognized in the statement of income unrealized losses on commodity based derivatives of $4.6 million in 2007, unrealized gains of $7.6 million in 2006, and unrealized losses of $3.2 million in 2005.

At December 31, 2007 and 2006, we had the following open commodity based derivative instruments designed as an economic hedge for a portion of our oil and natural gas production for periods after December 2007:

Petroleum Development Corporation
Open Derivative Positions
(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2007					
Natural Gas	Cash Settled Option Sales	14,500,000	$ 10.69	$ 155,044	$ (293)
Natural Gas	Cash Settled Option Purchases	16,360,000	5.76	94,283	3,366
Oil	Cash Settled Futures/Swaps Purchases	585,600	84.20	49,308	(5,097)
					$ (2,024)
Positions maturing in 12 months following December 31, 2007					
Natural Gas	Cash Settled Option Sales	14,500,000	$ 10.69	$ 155,044	$ (293)
Natural Gas	Cash Settled Option Purchases	16,360,000	5.76	94,283	3,366
Oil	Cash Settled Futures/Swaps Purchases	585,600	84.20	49,308	(5,097)
					$ (2,024)
The maximum term for the derivative contracts listed above is 12 months.					
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Option Sales	17,390,000	$ 5.56	$ 96,613	$ 12,597

Natural Gas	Cash Settled Option Purchases	2,155,000	10.34	22,287	(14)
Oil	Cash Settled Option Purchases	300,000	50.00	15,000	155
					$ 12,738

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Riley Natural Gas
Open Derivative Positions
(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	588,950	$ 7.79	$ 4,586	$ (246)
Natural Gas	Cash Settled Futures/Swaps Sales	2,085,400	8.50	17,722	1,236
Natural Gas	Cash Settled Basis Swap Purchases	397,500	0.54	214	3
Natural Gas	Physical Purchases	2,085,400	8.51	17,748	(473)
Natural Gas	Physical Sales	518,951	8.50	4,409	129
					$ 649
Positions maturing in 12 months following December 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	588,950	$ 7.79	$ 4,586	$ (246)
Natural Gas	Cash Settled Futures/Swaps Sales	1,568,400	8.54	13,391	1,318
Natural Gas	Cash Settled Basis Swap Purchases	397,500	0.54	214	3
Natural Gas	Physical Purchases	1,568,400	8.32	13,044	(655)
Natural Gas	Physical Sales	518,951	8.50	4,409	129
					$ 549

The maximum term for the derivative contracts listed above is 48 months.

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Futures/Swaps Purchases	246,900	$ 7.34	$ 1,811	$ (304)
Natural Gas	Cash Settled Futures/Swaps Sales	1,952,150	8.42	16,444	2,815

Natural Gas	Cash Settled Basis Swap Purchases	90,000	0.42	38	(12)
Natural Gas	Cash Settled Basis Swap Sales	20,000	0.50	10	4
Natural Gas	Cash Settled Option Purchases	220,000	5.50	1,210	64
Natural Gas	Cash Settled Option Sales	110,000	10.10	1,111	(39)
Natural Gas	Physical Purchases	1,964,150	8.27	16,244	(1,974)
Natural Gas	Physical Sales	114,974	9.62	1,106	310
Natural Gas	Physical Basis Purchases	20,000	0.45	9	(3)
Natural Gas	Physical Basis Sales	90,000	0.44	39	14
					$ 875

In addition to including the gross assets and liabilities related to our share of oil and gas production, the above tables and our consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into on behalf of the affiliate partnerships as the managing general partner. Our consolidated balance sheets include the fair value of derivatives and a corresponding net receivable from the partnerships of $1.5 million at December 31, 2007, and a corresponding net payable to the partnerships of $7.5 million as of December 31, 2006.

We are required to maintain margin deposits with brokers for outstanding futures contracts. As of December 31, 2007 and 2006, restricted cash in the amount of $0.3 million and $0.5 million was on deposit.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

The following table identifies the fair value of commodity based derivatives as classified in our consolidated balance sheets.

	December 31, 2007	December 31, 2006
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives - current asset	$ 4,817	$ 15,012
Other assets - long-term asset	193	1,146
	5,010	16,158
Fair value of derivatives - current liability	6,291	2,545
Other liabilities - long-term liability	93	-
	6,384	2,545
Net fair value of commodity based derivatives - (liability) asset	$ (1,374)	$ 13,613

The following changes in the fair value of commodity based derivatives are reflected in our consolidated statements of income (in millions):

	Twelve Months Ended December 31,					
	2007		2006		2005	
Statement of income line item	Realized	Unrealized	Realized	Unrealized	Realized	Unrealized
	(in thousands, gain/(loss))					
Oil and gas price risk management gain (loss), net (1)	$ 7,173	$ (4,417)	$ 1,895	$ 7,252	$ (6,367)	$ (3,001)
Sales from natural gas marketing activities (2)	3,870	(1,736)	2,592	12,291	(5,643)	(8,472)
Cost of natural gas marketing activities (2)	(482)	1,511	(1,908)	(11,923)	(1,266)	8,247

(1) Includes realized and unrealized gains and losses on commodity based derivative instruments related to PDC.
(2) Includes realized and unrealized gains and losses on commodity based derivatives instruments related to RNG only.

Pursuant to SFAS No. 133, at this time our derivatives do not qualify for designation as cash flow hedges. Changes in the fair value of these non-qualifying derivatives that occur prior to their maturity (i.e., temporary fluctuations in value) are reported currently in our consolidated statements of operations as unrealized gains (losses). Oil and gas price risk management gain (loss), net includes realized and unrealized gains and losses on commodity based derivatives related to our oil and gas sales. Gas sales from marketing activities and cost of gas marketing activities includes realized and unrealized gains and losses on commodity based derivatives related to the RNG gas sales and gas purchases, respectively.

NOTE 16 - SALE OF OIL AND GAS PROPERTIES

Grand Valley Field Properties

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

Pursuant to the purchase and sale agreement, we were obligated to either drill 16 wells on specifically identified acreage over the next three years or pay liquidated damages of $1.6 million per un-drilled well for a total contingent obligation of $25.6 million, which was reflected as a deferred gain on sale of leaseholds on the balance sheet as of December 31, 2006. In May 2007, we entered into a letter agreement amending the original purchase and sale agreement. The letter agreement relieved us of the obligation, in its entirety, to either drill 16 wells or pay liquidated damages, resulting in the recognition of the remaining $25.6 million deferred gain on sale of leaseholds in the second quarter of 2007. Pursuant to the letter agreement, we were obligated to drill six wells on specifically identified acreage. As of December 31, 2007, we had drilled all six wells, which were drilled on the unaffiliated party's leasehold for its benefit and at its cost.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

In conjunction with the purchase and sale agreement described above, we entered into a LKE agreement, in accordance with Section 1031 of the Internal Revenue Code, with a "qualified intermediary." Proceeds in the amount of $300 million were transferred directly to the qualified intermediary to be held in trust pursuant to the terms of the LKE agreement. We had until mid-January 2007 to close any acquisition of suitable like-kind property, allowing us to take advantage of the income tax deferral benefits of a LKE transaction.

In December 2007, we sold to the same unaffiliated party above a portion of our North Dakota properties for approximately $34.7 million. The properties, located in Dunn, Williams and McKenzie Counties, North Dakota, include interests in five producing Bakken wells and approximately 72,000 net undeveloped acres. The reduction in our production and proved reserves as a result of this transaction is not material. We recorded a gain on sale of leaseholds of $7.7 million in the fourth quarter of 2007. The proceeds from the sale were used to pay down debt. Following the sale, we retain ownership in three producing wells in Dunn County, ten producing wells in Burke County and approximately 60,000 acres of undeveloped leasehold in Burke County.

During 2005, we sold a portion of an undeveloped leasehold in the Grand Valley Field to an unaffiliated entity. The proceeds of the sale were $6.2 million and our carrying value of the property was zero. The gain of $6.2 million was recognized in 2005 and is included in gain on sale of leaseholds in our consolidated statement of income.

Appalachian Basin Properties

Additionally, in 2005, we completed the sale to an unaffiliated party of 111 Pennsylvania wells we purchased in 1998. We received proceeds of $3.4 million and recorded a gain of $1.5 million, which is included in gain on sale of leaseholds in our consolidated statement of income.

NOTE 17 - BUSINESS SEGMENTS

Our operating activities can be divided into four major segments: oil and gas well drilling operations, natural gas marketing, oil and gas sales, and well operations and pipeline income. We drill natural gas wells for Company-sponsored drilling partnerships and retain an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. We own an interest in approximately 4,354 wells from which we sell our oil and gas production from our working interests in the wells. We charge Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the years ended December 31, 2007, 2006 and 2005 is presented below.

Year Ended December 31,	2007	2006	2005
Revenues:		(in thousands)	
Oil and gas sales (1)	$ 177,943	$ 124,336	$ 93,191
Natural gas marketing	103,624	131,326	121,114
Oil and gas well drilling operations	12,154	17,917	99,963
Well operations and pipeline income	9,342	10,704	8,760
Unallocated amounts	2,172	2,220	2,170
Total	$ 305,235	$ 286,503	$ 325,198
Segment Income Before Income Taxes:			

Oil and gas sales (2)	$ 42,068	$ 61,868	$ 46,095
Natural gas marketing	3,822	1,816	1,737
Oil and gas well drilling operations	9,646	5,300	11,778
Well operations and pipeline income (3)	3,136	2,823	3,539
Unallocated amounts (4)(5)	(4,482)	315,602	2,979
Total	$ 54,190	$ 387,409	$ 66,128

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

As of December 31,	2007	2006	2005
Segment Assets:			
Oil & gas sales	$ 862,237	$ 394,952	$ 251,897
Natural gas marketing	40,269	39,899	56,518
Oil and gas well drilling operations	4,959	87,746	89,030
Well operations and pipeline income	26,156	28,895	31,407
Unallocated amounts (6)	116,858	332,795	15,509
Total	$ 1,050,479	$ 884,287	$ 444,361
Year ended December 31,			
Expenditures for Segment Long-Lived Assets:			
Oil & gas sales	$ 226,801	$ 133,401	$ 92,907
Natural gas marketing	-	-	1
Oil and gas well drilling operations	-	-	-
Well operations and pipeline income	6,715	1,419	3,949
Unallocated amounts	5,472	12,125	2,452
Total	$ 238,988	$ 146,945	$ 99,309

(1) Includes oil and gas price risk management gain (loss), net.
(2) Includes $23.6, $8.1 and $11.1 million in exploration costs and $68.1, $31.3 and $19.3 million in DD&A expense in 2007, 2006 and 2005, respectively.
(3) Includes $1.2, $1.9 and $1.5 million in DD&A expense in 2007, 2006 and 2005, respectively.
(4) Includes interest income for PDC operations, $0.8, $0.6 and $0.3 million in interest income allocated to natural gas marketing in 2007, 2006 and 2005, respectively, in addition to partnership management fees.
(5) Includes $1.6, $0.5, and $0.3 million in DD&A expense in 2007, 2006 and 2005 respectively.
(6) The December 31, 2006, amount was expended in early 2007 in LKE transactions; the assets and liabilities of which have been included in the oil and gas sales segment.

NOTE 18 – SUPPLEMENTAL CASH FLOW

	Year Ended December 31,		
	2007	2006	2005
	(in thousands)		
Cash paid for:			
Interest	$ 12,557	$ 3,011	$ 101
Income taxes	43,785	46,735	10,675
Non-cash investing activities:			
Change in deferred tax liability resulting from reallocation of acquisition purchase price	4,188	-	-
Changes in accounts payable - affiliates related to acquisition of partnerships	668	-	-
Changes in accounts payable related to purchases of properties and equipment	32,820	1,800	-
Changes related to investment in drilling partnership	18,712	(7,151)	(7,160)

Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	7,850	3,164	(3)

NOTE 19 – SUBSEQUENT EVENTS

Issuance and Sale of Senior Notes

On February 8, 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018. The senior notes were offered and sold in private transactions pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended. The offer and sale of the senior notes were not registered under the Securities Act.

The senior notes accrue interest from February 8, 2008, at a rate of 12% per year and interest is payable semi-annually in arrears on February 15 and August 15 of each year, commencing on August 15, 2008. The notes are senior unsecured obligations and rank, in right of payment, equally with all of our existing and future senior unsecured indebtedness and senior to any of our existing and future subordinated indebtedness. The notes are effectively subordinated to any of our existing or future secured indebtedness to the extent of the assets securing such indebtedness.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

We may, at our option, redeem all or part of the notes, at any time prior to February 15, 2013, at a make-whole price, and on or after February 15, 2013, at fixed redemption prices, plus accrued and unpaid interest, if any, to the date of redemption.

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

- at least 65% of the aggregate principal amount of the notes issued on February 8, 2008, remains outstanding after each such redemption; and
- the redemption occurs within 180 days after the closing of the equity offering.

The indenture governing the senior notes contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company.

Additionally, if we experience certain kinds of changes of control, we must give holders of the notes the opportunity to sell to us their notes at 101% of their principal amount, plus accrued and unpaid interest.

We used the net proceeds from the sale of the senior notes to repay debt outstanding under our revolving credit facility and for general corporate purposes.

Registration Rights Agreement

On February 8, 2008, we entered into a registration rights agreement with the initial purchasers named therein, pursuant to which we agreed to use our commercially reasonable efforts to (i) file with the SEC a registration statement on an appropriate form under the Securities Act relating to a registered exchange offer for the notes described above under the Securities Act and (ii) cause the exchange offer registration statement to be declared effective under the Securities Act within 365 days following February 8, 2008. If we fail to comply with certain obligations under the registration rights agreement, we will be required to pay liquidated damages to the holders of our senior notes in accordance with the provisions of the registration rights agreement. We do not believe it is probable that we will be required to make such payments; therefore, have not recorded a liability at this time.

Departure of Executive Officer

On February 8, 2008, we accepted the resignation for good reason of Thomas E. Riley as our President and Director. In accordance with the provisions of his employment agreement, Mr. Riley will receive a single lump sum cash payment of $1,877,343 as separation compensation and retirement compensation equal to $37,500 per year for ten years beginning January 1, 2009. Additionally, a separation agreement executed on February 8, 2008, provides for the of vesting 16,123 shares of restricted stock and stock options to purchase 4,678 shares of our common stock. We will recognize expense of approximately $3.2 million in the first quarter of 2008 in connection with the resignation of Mr. Riley.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 20 – SUPPLEMENTAL OIL AND GAS INFORMATION - UNAUDITED

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (Unaudited)

We incurred costs in oil and gas property acquisition, exploration and development are presented below.

	Year Ended December 31, 2007	2006	2005
	(in thousands)		
Acquisition of properties:			
Proved properties	$ 257,330	$ 802	$ 1,608
Unproved properties	13,701	11,926	16,910
Development costs	194,031	114,487	68,605
Exploration costs:			
Exploratory drilling	12,972	18,660	12,943
Geological and Geophysical	6,299	2,234	-
Total costs incurred	$ 484,333	$ 148,109	$ 100,066

The proved reserves attributable to the development costs in the above table were 216,383 MMcf and 3,700 MBbls for 2007, 64,126 MMcf and 2,955 MBbls for 2006 and 76,669 MMcf and 1,576 MBbls for 2005. Of the above development costs incurred for the years ended December 31, 2007, 2006 and 2005, the amounts of $37.1 million, $20.1 million and $23.8 million, respectively, were incurred to develop proved undeveloped properties from the prior year end.

Property acquisition costs include costs incurred to purchase, lease or otherwise acquire a property. Development costs include costs incurred to gain access to and prepare development well locations for drilling, to drill and equip development wells, recompletions and to provide facilities to extract, treat, gather and store oil and gas. Exploration costs include costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves.

Capitalized Oil and Gas Costs (Unaudited)

Aggregate capitalized costs for related to oil and gas exploration and production activities with applicable accumulated depreciation, depletion and amortization are presented below:

	December 31, 2007	2006
	(in thousands)	
Proved oil and gas properties	$ 953,904	$ 473,451
Unproved oil and gas properties	41,023	27,055
	994,927	500,506
	196,310	133,172

Less accumulated depreciation, depletion and amortization		
	$ 798,617	$ 367,334

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

Results of Operations for Oil and Gas Producing Activities (Unaudited)

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

	Year Ended December 31,		
	2007	2006	2005
		(in thousands)	
Revenue:			
Oil and gas sales	$ 175,187	$ 115,189	$ 102,559
Oil and gas price risk management gain (loss), net	2,756	9,147	(9,368)
	177,943	124,336	93,191
Expenses:			
Production costs	44,238	20,855	16,194
Depreciation, depletion and amortization	68,086	30,988	19,322
Exploration costs	23,551	8,131	11,115
	135,875	59,974	46,631
Results of operations for oil and gas producing activities before provision for income taxes	42,068	64,362	46,560
Provision for income taxes	16,280	24,818	18,112
Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)	$ 25,788	$ 39,544	$ 28,448

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

Net Proved Oil and Gas Reserves (Unaudited)

Our proved oil and natural gas reserves have been estimated by independent petroleum engineers. Wright & Company prepared for us reserve reports estimating our proved reserves at December 31, 2007 and 2006, in the Appalachian and Michigan Basins. Ryder Scott Company, L.P. prepared for us reserve reports estimating our proved reserves at December 31, 2007 and 2006, in the Rocky Mountain Region. Wright & Company prepared reserve reports for us estimating all of our reserves at December 31, 2005, with the exception of our North Dakota wells, which were prepared by Ryder Scott Company, L.P. These reserve estimates have been prepared in compliance with professional standards and the reserves definitions prescribed by the SEC.

Proved reserves are the estimated quantities of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Estimates of proved reserves may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. The Company's net proved reserve estimates have been adjusted as necessary to reflect all contractual agreements, royalty obligations and interests owned by others at the time of the estimate.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

An analysis of the change in estimated quantities of oil and gas reserves, all of which are located within the United States, is shown below.

	Oil (MBbl)	Gas (MMcf)	Total (MMcfe)
Proved Reserves:			
Proved reserves, January 1, 2005	3,316	197,548	217,444
Revisions of previous estimates	80	(6,894)	(6,414)
Extensions, discoveries and other additions			
Rocky Mountain Region	1,576	76,669	86,125
Purchases of reserves			
Appalachian basin	-	434	434
Michigan Basin	-	47	47
Rocky Mountain region	5	71	101
Dispositions to partnerships	-	(9,556)	(9,556)
Production	(439)	(11,031)	(13,665)
Proved reserves, December 31, 2005	4,538	247,288	274,516
Revisions of previous estimates	226	(21,721)	(20,365)
Extensions, discoveries and other additions			
Michigan Basin	-	225	225
Rocky Mountain Region	2,955	63,901	81,631
Purchases of reserves			
Appalachian basin	-	222	222
Michigan Basin	-	35	35
Rocky Mountain region	276	3,504	5,160
Dispositions to partnerships	(92)	(1,215)	(1,767)
Production	(631)	(13,161)	(16,947)
Proved reserves, December 31, 2006	7,272	279,078	322,710
Revisions of previous estimates	1,375	14,177	22,427
Extensions, discoveries and other additions			
Appalachian Basin	-	5,493	5,493
Michigan Basin	-	488	488
Rocky Mountain Region	3,700	210,402	232,602
Purchases of reserves			
Appalachian basin	2	63,014	63,026
Michigan Basin	-	6,059	6,059
Rocky Mountain region	4,490	39,239	66,179
Dispositions to partnerships	(591)	(1,874)	(5,420)
Production	(910)	(22,513)	(27,973)
Proved reserves, December 31, 2007	15,338	593,563	685,591

Proved Developed Reserves, As of:			
January 1, 2005	3,190	146,152	165,292
December 31, 2005	3,860	155,354	178,514
December 31, 2006	4,629	158,978	186,752
December 31, 2007	8,927	314,123	367,685

2007 Activity. In 2007, we recorded an upward revision to our previous estimate of proved reserves of approximately 22 Bcfe. The revision was primarily due to an increase of approximately 25 Bcfe and 12 Bcfe, respectively, due to asset performance and higher commodity prices, partially offset by a decrease of approximately 15 Bcfe due primarily to increased operating costs, adjustments to proved undeveloped reserve values and change in well ownership interests. New discoveries and extensions of 239 Bcfe in 2007 are due to the drilling of 218 net wells and the addition of new proved undeveloped reserves. Approximately 233 Bcfe were added in the Rocky Mountain Region, with 43 Bcfe in the Wattenberg Field, 170 Bcfe in Grand Valley Field and 19 Bcfe in the NECO area. We acquired approximately 135 Bcfe of proved reserves through purchases of oil and natural gas properties. In the Rocky Mountain Region approximately 66 Bcfe of proved reserves were acquired in the Wattenberg Field, in the Appalachian Basin approximately 75 Bcfe were acquired and approximately 6 Bcfe in the Michigan Basin. We sold proved reserves of approximately 5 Bcfe to unaffiliated third parties and to our sponsored partnerships for drilling activity.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

2006 Activity. In 2006 we recorded a downward revision to our previous estimate of proved reserves of approximately 20 Bcfe. The revision was primarily due to a decrease of 3 Bcfe due to asset performance and a decrease of 10 Bcfe due to lower commodity prices and a decrease of approximately 7 Bcfe due to changes in proved undeveloped reserve value, operating expense, and well ownership interests. New discoveries and extensions in 2006 of approximately 82 Bcfe were primarily due to the drilling of 91 net wells and adding new proved undeveloped reserves in the Rocky Mountain Region. Approximately 34 Bcfe were added in Wattenberg Field, 33 Bcfe in Grand Valley Field and 12 Bcfe in the NECO area. We acquired approximately 5 Bcfe of proved reserves through purchases of oil and natural gas properties in Wattenberg Field. We sold proved reserves of approximately 2 Bcfe to our sponsored partnerships.

2005 Activity. In 2005, we recorded a downward revision to our previous estimate of proved reserves of approximately 6 Bcfe. The revision was primarily due to a decrease of 15 Bcfe due to asset performance, partially offset by additions of 6 Bcfe and 3 Bcfe, respectively, due to commodity price increases and proved undeveloped values, operating expense changes and well ownership interests. New discoveries and extensions in 2005 of approximately 86 Bcfe were primarily due to the drilling of 65 net wells and additions of new proved undeveloped reserves in the Rocky Mountain Region. Approximately 11 Bcfe were added in Wattenberg Field, 44 Bcfe were added in Grand Valley Field and 27 Bcfe were added in the NECO area. We sold proved reserves of approximately 10 Bcfe to our sponsored partnership.

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

Summarized in the following table is information with respect to the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. Future cash inflows are computed by applying year-end prices of oil and gas relating to our proved reserves to the year-end quantities of those reserves. Future production, development, site restoration and abandonment costs are derived based on current costs assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the statutory rate in effect at the end of each year to the future pretax net cash flows, less the tax basis of the properties and gives effect to permanent differences, tax credits and allowances related to the properties.

	2007	2006	2005
		(in thousands)	
Future estimated cash flows	$ 5,257,962	$ 1,804,796	$ 2,381,238
Future estimated production costs	(1,374,027)	(571,346)	(545,683)
Future estimated development costs	(876,961)	(373,460)	(207,164)
Future estimated income tax expense	(1,159,489)	(334,536)	(633,444)
Future net cash flows	1,847,485	525,454	994,947
10% annual discount for estimated timing of cash flows	(1,094,414)	(309,792)	(589,517)
Standardized measure of discounted future estimated net cash flows	$ 753,071	$ 215,662	$ 405,430

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

	2007	2006 (in thousands)	2005
Sales of oil and gas production net of production costs	$ (137,725)	$ (94,337)	$ (86,366)
Net changes in prices and production costs	157,797	(301,132)	188,836
Extensions, discoveries, and improved recovery, less related costs	317,031	46,109	150,654
Sales of reserves	(7,846)	(3,356)	(14,456)
Purchase of reserves	342,792	11,003	1,266
Development costs incurred during the period	42,510	20,051	24,035
Revisions of previous quantity estimates	92,462	(22,090)	4,917
Changes in estimated income taxes	(335,327)	120,818	(112,054)
Accretion of discount	38,660	62,838	38,241
Timing and other	27,055	(29,672)	(19,071)
Total	$ 537,409	$ (189,768)	$ 176,002

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

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

The estimated present value of future cash flows relating to proved reserves is extremely sensitive to prices used at any measurement period. The average December 31 price used for each commodity at December 31, 2007, 2006 and 2005 is presented below.

	Average Price	
As of December 31,	Oil	Gas
2007	$ 80.67	$ 6.77
2006	57.70	4.96
2005	58.25	8.56

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

NOTE 21 - QUARTERLY FINANCIAL DATA (UNAUDITED)

Quarterly financial data for the years ended December 31, 2007 and 2006, are presented below The sum of the quarters may not equal the total of the year's net income per share due to changes in the weighted average shares outstanding throughout the year.

	2007				
	Quarter				
	First	Second	Third	Fourth	Year
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 34,016	$ 39,246	$ 44,437	$ 57,488	$ 175,187
Sales from natural gas marketing activities	21,987	29,924	19,934	31,779	103,624
Oil and gas well drilling operations	4,030	1,739	1,573	4,812	12,154
Well operations and pipeline income	3,298	1,292	2,092	2,660	9,342
Oil and gas price risk management (loss) gain, net	(5,645)	3,742	6,345	(1,686)	2,756
Other income	226	2	1,894	50	2,172
Total revenues	57,912	75,945	76,275	95,103	305,235
Costs and expenses:					
Oil and gas production costs and well operations costs	9,035	11,628	12,645	15,956	49,264
Cost of natural gas marketing activities	21,512	28,780	19,810	30,482	100,584
Cost of oil and gas well drilling operations	564	246	749	949	2,508
Exploration expense	2,678	6,780	5,337	8,756	23,551
General and administrative expense	7,424	6,886	7,513	9,145	30,968
Depreciation, depletion and amortization	13,074	17,429	20,354	19,987	70,844
Total costs and expenses	54,287	71,749	66,408	85,275	277,719
Gain on sale of leaseholds	-	25,600	-	7,691	33,291
Income from operations	3,625	29,796	9,867	17,519	60,807
Interest income	1,143	454	462	603	2,662
Interest expense	(831)	(1,450)	(2,544)	(4,454)	(9,279)
Income before income taxes	3,937	28,800	7,785	13,668	54,190
Income taxes	1,436	10,749	3,326	5,470	20,981
Net income	$ 2,501	$ 18,051	$ 4,459	$ 8,198	$ 33,209
Basic earnings per common share	$ 0.17	$ 1.22	$ 0.30	$ 0.56	$ 2.25
Diluted earnings per common share	$ 0.17	$ 1.21	$ 0.30	$ 0.55	$ 2.24

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – (Continued)

	2006				
	Quarter First	Second	Third	Fourth	Year
	(in thousands, except per share data)				
Revenues:					
Oil and gas sales	$ 28,332	$ 27,992	$ 30,577	$ 28,288	$ 115,189
Sales from natural gas marketing activities	41,942	29,129	30,374	29,880	131,325
Oil and gas well drilling operations	5,278	3,745	2,659	6,235	17,917
Well operations and pipeline income	2,290	2,486	2,536	3,392	10,704
Oil and gas price risk management gain, net	4,925	1,370	2,707	145	9,147
Other income	3	21	1,964	233	2,221
Total revenues	82,770	64,743	70,817	68,173	286,503
Costs and expenses:					
Oil and gas production and well operations costs	6,949	6,830	8,584	6,658	29,021
Cost of natural gas marketing activities	41,780	28,471	29,988	29,911	130,150
Cost of oil and gas well drilling operations	4,212	3,278	3,838	1,289	12,617
Exploration expense	1,208	1,898	2,180	2,845	8,131
General and administrative expense	3,719	5,102	5,357	4,869	19,047
Depreciation, depletion and amortization	6,587	7,605	8,300	11,243	33,735
Total costs and expenses	64,455	53,184	58,247	56,815	232,701
Gain on sale of leaseholds	-	-	328,000	-	328,000
Income from operations	18,315	11,559	340,570	11,358	381,802
Interest income	392	349	3,475	3,834	8,050
Interest expense	(352)	(436)	(366)	(1,289)	(2,443)
Income before income taxes	18,355	11,472	343,679	13,903	387,409
Income taxes	6,710	4,192	132,795	5,940	149,637
Net income	$ 11,645	$ 7,280	$ 210,884	$ 7,963	$ 237,772
Basic earnings per common share	$ 0.72	$ 0.45	$ 13.39	$ 0.54	$ 15.18
Diluted earnings per common share	$ 0.72	$ 0.45	$ 13.33	$ 0.54	$ 15.11

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PETROLEUM DEVELOPMENT CORPORATION

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1	Charged to Costs and Expenses	Deductions	Ending Balance December 31
	(in thousands)			
2007:				
Allowance for doubtful accounts (a)	$ 415	$ 50	$ 108	$ 357
Valuation allowance for unproved oil and gas properties (b)	$ 596	$ 2,183	$ 414	$ 2,365
2006:				
Allowance for doubtful accounts (a)	$ 409	$ 7	$ 1	$ 415
Valuation allowance for unproved oil and gas properties (b)	$ 33	$ 653	$ 90	$ 596
2005:				
Allowance for doubtful accounts (a)	$ 409	$ -	$ -	$ 409
Valuation allowance for unproved oil and gas properties (b)	$ -	$ 81	$ 48	$ 33

(a) Deductions represent the write-off of accounts receivable deemed uncollectible.
(b) Deductions represent amortization of expired or abandoned unproved oil and gas properties.