PETROLEUM DEVELOPMENT CORP
Form 424B3
May 23, 2008
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**Filed Pursuant to Rule 424(b)(3)**
**Registration No. 333-150420**

**PROSPECTUS**

# $203,000,000

# Petroleum Development Corporation

**Offer to Exchange**

**All Outstanding 12% Senior Notes due 2018**

**for**

**12% Senior Notes due 2018**

**THE EXCHANGE OFFER WILL EXPIRE AT 5:00 P.M.,**

**NEW YORK CITY TIME, ON JUNE 23, 2008, UNLESS EXTENDED**

**The Notes**

We are offering to exchange all of our outstanding 12% Senior Notes due 2018, which we refer to as the old notes, for our new 12% Senior Notes due 2018, which we refer to as the new notes. We refer to the old notes and new notes collectively as the notes.

**Terms of The Exchange Offer:**

The terms of the new notes will be substantially identical to the old notes, except that the new notes will not be subject to transfer restrictions or registration rights relating to the old notes. The new notes will represent the same debt as the old notes, and will be issued under the same indenture.

Interest on the new notes will accrue from February 8, 2008 at the rate of 12% per annum, payable on February 15 and August 15 of each year, beginning on August 15, 2008.

We will exchange an equal principal amount of all old notes for new notes that you validly tender and do not validly withdraw before the exchange offer expires. We do not currently intend to extend the exchange offer.

You may withdraw tenders of the old notes at any time prior to the expiration of the exchange offer.

The exchange of old notes for new notes will not be a taxable event for United States federal income tax purposes.

We will not receive any proceeds from this exchange offer.

There is no existing market for the new notes to be issued, and we do not intend to apply for their listing on any securities exchange or arrange for them to be quoted on any quotation system.

See the section entitled Description of Notes that begins on page 127 for more information about the notes.

**This investment involves risks. See the section entitled Risk Factors that begins on page 13 for a discussion of the risks that you should consider in connection with your investment in the notes.**

**Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.**

Each broker-dealer that receives new notes for its own account pursuant to the exchange offer must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for old notes where such old notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. See Plan of Distribution.

**The date of this prospectus is May 23, 2008.**

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## NOTICE TO INVESTORS

Except as described below, based on interpretations of the staff of the SEC set forth in no-action letters issued to third parties, we believe that the new notes issued in exchange for old notes may be offered for resale, resold, and otherwise transferred by a holder without further registration under the Securities Act of 1933 and without delivering a prospectus in connection with any resale of the new notes, provided that the holder:

- is acquiring the new notes in the ordinary course of its business;

- is not engaging nor intends to engage, and has no arrangement or understanding with any person to participate, in the distribution of the new notes; and

- is not an affiliate of Petroleum Development Corporation within the meaning of Rule 405 under the Securities Act.

Holders wishing to tender their old notes in the exchange offer must represent to us that these conditions have been met.

Any holder who tenders in the exchange offer for the purpose of participating in a distribution of the new notes cannot rely on these interpretations by the SEC staff and must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a secondary resale transaction. Unless an exemption from registration is otherwise available, any secondary resale by a holder intending to distribute new notes should be covered by an effective registration statement under the Securities Act containing the selling security holder information required by Item 507 of Regulation S-K under the Securities Act.

Each broker-dealer who holds old notes acquired for its own account as a result of market-making or other trading activities may exchange the old notes pursuant to the exchange offer. However, the broker-dealer may be

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deemed to be an underwriter within the meaning of the Securities Act and must, therefore, deliver a prospectus meeting the requirements of the Securities Act in connection with its initial resale of each new note received in the exchange offer. The letter of transmittal states that by acknowledging and delivering a prospectus, a broker-dealer will not be deemed to admit that it is an underwriter within the meaning of the Securities Act.

Under existing interpretations of the SEC and for so long as the registration statement of which this prospectus is a part is effective under the Securities Act, a broker-dealer may use this prospectus, as it may be amended or supplemented from time to time, in connection with its resales of new notes received for its account in exchange for old notes that were acquired by the broker-dealer as a result of market-making or other trading activities. The SEC may change these interpretations at any time. We have agreed that until the earlier of (i) the close of business 180 days after the expiration date of the exchange offer and (ii) the date on which all broker-dealers have sold all such new notes, we will make this prospectus available to any broker-dealer for use in connection with any such resale. See Plan of Distribution. If we do not receive any letters of transmittal from broker-dealers requesting to use this prospectus in connection with resales of new notes, we intend to terminate the effectiveness of the registration statement as soon as practicable after the consummation or termination of the exchange offer. After we terminate the effectiveness of the registration statement, broker-dealers will not be able to use this prospectus in connection with resales of new notes. As a result, any broker-dealers intending to use this prospectus in connection with resales of new notes must deliver to us a letter of transmittal so stating.

The old notes and the new notes constitute new issues of securities with no established public trading market. We do not intend to apply for listing of the old notes or the new notes on any securities exchange or for inclusion of the old notes or the new notes in any automated quotation system. We cannot assure you that:

- an active public market for the new notes will develop;
- any market that may develop for the new notes will be liquid; or
- holders will be able to sell the new notes at all or at favorable prices.

Future trading prices of the new notes will depend on many factors, including among other things, prevailing interest rates, our operating results, our credit rating and the market for similar securities.

**The exchange offer is not being made to, nor will we accept surrenders for exchange from, holders of old notes in any jurisdiction in which the exchange offer or the acceptance thereof would violate the securities or blue sky laws of that jurisdiction.**

## SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements within the meaning of Section 27A of the Securities Act regarding our business, financial condition, results of operations and prospects. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein, which include statements of estimated oil and gas production and reserves, drilling plans, future cash flows, anticipated capital expenditures and our management s strategies, plans and objectives. However, these are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this prospectus 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;

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- the timing and extent of our success in discovering, acquiring, developing and producing natural gas and oil reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- the availability of capital to us;
- risks incident to the drilling and operation of natural gas and oil wells;
- future production and development costs;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the United States;
- the effect of natural gas and oil derivatives activities; and
- conditions in the capital markets.

You should not place undue reliance on forward-looking statements, which speak only as of the date of this prospectus. 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 prospectus or currently unknown facts or conditions or the occurrence of unanticipated events.

**Further information about the risks and uncertainties that may affect us are described in Risk Factors. You should read that section carefully.**

## DEFINITIONS

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

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

**Bcf** One billion cubic feet.

**Bcfe** One billion cubic feet of natural gas equivalent.

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

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

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

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

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

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

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

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

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

**MBbls** One thousand barrels.

**Mcf** One thousand cubic feet.

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

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

**MMcf** One million cubic feet.

**MMcfe** One million cubic feet of natural gas equivalent.

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

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

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

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

**Oil** Crude oil or condensate.

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

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

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

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

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

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

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

**Recompletion** A recompletion occurs when the producer reenters a well to complete (i.e., perforate) a new formation from that in which a well has previously been completed.

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

**SEC** The United States Securities and Exchange Commission.

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

**Tcf** One trillion cubic feet.

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

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

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

## AVAILABLE INFORMATION

We have filed a registration statement with the SEC under the Securities Act that registers the issuance and sale of the securities offered by this prospectus. The registration statement, including the attached exhibits, contains additional relevant information about us. The rules and regulations of the SEC allow us to omit some information included in the registration statement from this prospectus.

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We file annual, quarterly, and other reports, proxy statements and other information with the SEC under the Securities Exchange Act of 1934, as amended. You may read and copy any materials we file with the SEC at the SEC s public reference room at 100 F Street, N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the public reference room. Our SEC filings are also available to the public through the SEC s website at *http://www.sec.gov*. General information about us, including our annual reports on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, as well as any amendments and exhibits to those reports, are available free of charge through our website at *http://www.petd.com* as soon as reasonably practicable after we file them with, or furnish them to, the SEC. However, information on our website and our other SEC filings mentioned above are not incorporated into this prospectus and are not a part of this prospectus.

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**PROSPECTUS SUMMARY**

*This summary is not complete. It highlights selected information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including the information under the heading Risk Factors, our financial statements and the notes to those financial statements. Unless otherwise indicated or the context requires otherwise (for example, when describing the terms of the notes), references in this prospectus to PDC, we, us, our or ours refer, collectively, to Petroleum Development Corporation, its subsidiaries and its drilling partnerships, to the extent that such drilling partnerships are proportionately consolidated.*

*Please see the Definitions beginning on page iii for the definitions of certain natural gas and oil industry terms used in this Prospectus.*

**Our Business**

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 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 drill bit 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.

**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.

*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

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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 we bore the risk of changes in costs. In addition, we have typically purchased a 20% to 37% working interest in the wells developed through these partnerships. In September 2006, we raised approximately $90 million through investor subscriptions in one drilling partnership, and in August 2007, we raised approximately $90 million through an additional drilling partnership. Our 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 and 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

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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.

*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 area, 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. 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.

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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*

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. Completion operations have not commenced as we are awaiting the completion of a third party gas gathering infrastructure.

**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.

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*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.

*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.

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.

Our principal executive offices are located at 120 Genesis Boulevard, Bridgeport, West Virginia 26330, and our telephone number at that address is (304) 842-3597. Our website address is *http://www.petd.com*. However, information contained on our website is not incorporated by reference into this prospectus, and you should not consider the information contained on our website to be part of this prospectus.

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**Summary of the Terms of the Exchange Offer**

*On February 8, 2008, we completed a private offering of $203,000,00 aggregate principal amount of our 12.0% senior notes due 2018. In this prospectus, we refer to the notes that we issued in the February 2008 offering as our old notes. We entered into a registration rights agreement with the initial purchasers of the old notes in the private offering in which we agreed, among other things, to use our commercially reasonable efforts to complete this exchange offer. The following summary highlights selected information from this prospectus concerning the exchange offer and may not contain all of the information that is important to you. We encourage you to read the entire prospectus carefully.*

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|---|---|
| Old Notes | 12.0% senior notes due 2018. Transfer restrictions apply to the old notes. |
| New Notes | 12.0% senior notes due 2018. The terms of the new notes are substantially identical to those of the outstanding old notes, except that the transfer restrictions and registration rights relating to the old notes do not apply to the new notes. |
| The Exchange Offer | We are offering to exchange all old notes for the same aggregate principal amount of new notes, the offers and sales of which have been registered under the Securities Act. The old notes may be tendered only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof. We will exchange all old notes for new notes that are validly tendered and not withdrawn prior to the expiration of the exchange offer. We will cause the exchange to be effected promptly after the expiration date of the exchange offer. |

The new notes will evidence the same debt as the old notes and will be issued under and entitled to the benefits of the same indenture that governs the old notes. Because we have registered the offers and sales of the new notes, the new notes will not be subject to transfer restrictions, and holders of old notes that have tendered and had their outstanding notes accepted in the exchange offer will have no registration rights.

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| If You Fail to Exchange Your Old Notes | If you do not exchange your old notes for new notes in the exchange offer, you will continue to be subject to the restrictions on transfer provided in the old notes and the indenture governing those notes. In general, you may not offer or sell your old notes without registration under the federal securities laws or an exemption from the registration requirements of the federal securities laws and applicable state securities laws. |
| Procedures for Tendering Your Old Notes | If you wish to tender your old notes for new notes, you must: |

complete and sign the enclosed letter of transmittal by following the related instructions, and

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send the letter of transmittal, as directed in the instructions, together with any other required documents, to the exchange agent either (1) with the old notes to be tendered, or (2) in compliance with the specified procedures for guaranteed delivery of the old notes.

Brokers, dealers, commercial banks, trust companies and other nominees may also effect tenders by book-entry transfer.

By executing the letter of transmittal or by transmitting an agent s message in lieu thereof, you will represent to us that, among other things:

the new notes you receive will be acquired in the ordinary course of your business;

you are not participating, and you have no arrangement with any person or entity to participate, in the distribution of the new notes;

you are not our affiliate, as defined in Rule 405 under the Securities Act, or a broker-dealer tendering old notes acquired directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act; and

if you are not a broker-dealer, that you are not engaged in and do not intend to engage in the distribution of the new notes.

If your old notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee, we urge you to contact that person promptly if you wish to tender your old notes pursuant to this exchange offer. See The Exchange Offer Procedures for Tendering Old Notes. Please do not send your letter of transmittal or certificates representing your old notes to us. Those documents should be sent only to the exchange agent. Questions regarding how to tender and requests for information should be directed to the exchange agent. See The Exchange Offer Exchange Agent.

Resale of the New Notes

Except as provided below, we believe that the new notes may be offered for resale, resold and otherwise transferred by you without compliance with the registration and prospectus delivery provisions of the Securities Act *provided* that:

the new notes are being acquired in the ordinary course of business,

you are not participating, do not intend to participate, and have no arrangement or understanding with any person to participate in the distribution of the new notes issued to you in the exchange offer,

you are not our affiliate, and

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you are not a broker-dealer tendering old notes acquired directly from us for your account.

Our belief is based on interpretations by the staff of the SEC, as set forth in no-action letters issued to third parties that are not related to us. The SEC has not considered this exchange offer in the context of a no-action letter, and we cannot assure you that the SEC would make similar determinations with respect to this exchange offer. If any of these conditions are not satisfied, or if our belief is not accurate, and you transfer any new notes issued to you in the exchange offer without delivering a resale prospectus meeting the requirements of the Securities Act or without an exemption from registration of your new notes from those requirements, you may incur liability under the Securities Act. We will not assume, nor will we indemnify you against, any such liability. Each broker-dealer that receives new notes for its own account in exchange for old notes, where the old notes were acquired by such broker-dealer as a result of market-making or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of such new notes. See Plan of Distribution.

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| Expiration Date | The exchange offer will expire at 5:00 p.m., New York City time, on June 23, 2008, unless we decide to extend the expiration date. We do not currently intend to extend the exchange offer. |
| Conditions to the Exchange Offer | The exchange offer is not subject to any conditions other than that it does not violate applicable law or any applicable interpretation of the staff of the SEC. |
| Exchange Agent | We have appointed The Bank of New York as exchange agent for the exchange offer. You can reach the exchange agent at the address set forth on the back cover of this prospectus. For more information with respect to the exchange offer, you may call the exchange agent at (212) 815-3750; the fax number for the exchange agent is (212) 815-5704. |
| Withdrawal Rights | You may withdraw the tender of your old notes at any time before the expiration date of the exchange offer. You must follow the withdrawal procedures as described under the heading The Exchange Offer Withdrawal of Tenders. |
| Federal Income Tax Consequences | The exchange of old notes for new notes in the exchange offer will not be a taxable transaction for U.S. federal income tax purposes. See Material U.S. Federal Income Tax Considerations. |
| Acceptance of Old Notes and Delivery of New Notes | We will accept for exchange any and all old notes that are properly tendered in the exchange offer prior to the expiration date. See The Exchange Offer Procedures for Tendering Old Notes. The new notes issued pursuant to the exchange offer will be delivered promptly following the expiration date. |

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**Summary of the Terms of the New Notes**

*Set forth below is a brief summary of some of the principal terms of the new notes. You should also read the information under the caption Description of Notes later in this prospectus for a more detailed description and understanding of the terms of the new notes. In describing the terms of the notes, references to PDC, we, us and our mean Petroleum Development Corporation, and not any of its subsidiaries.*

| | |
|---|---|
| Issuer | Petroleum Development Corporation |
| New Notes | $203.0 million aggregate principal amount of 12.0% senior notes due 2018. |
| Maturity Date | February 15, 2018. |
| Interest Rate | 12.0% per year. |
| Interest Payment Dates | Each February 15 and August 15, beginning on August 15, 2008. Interest will accrue from February 8, 2008. |
| Subsidiary Guarantees | Initially, the new notes will not be guaranteed by any of our subsidiaries. Under specified conditions, certain of our subsidiaries may be required to guarantee the new notes in the future. Any such guarantee of the new notes may be released under certain circumstances. Each subsidiary guarantor s guarantee will be a general unsecured obligation of that subsidiary guarantor and will rank:<br>senior in right of payment to all existing and future subordinated indebtedness of that subsidiary guarantor;<br>equal in right of payment to all existing and future senior indebtedness of that subsidiary guarantor; and<br>effectively junior to that subsidiary guarantor s existing and future secured indebtedness, including any guarantee of indebtedness under our revolving credit facility, to the extent of the value of the assets of such subsidiary guarantor constituting collateral securing that indebtedness. |
| Ranking | The new notes will be our general unsecured, senior obligations. Accordingly, they will rank:<br>senior in right of payment to all of our existing and future subordinated indebtedness; |

equal in right of payment with any of our existing and future senior indebtedness;

effectively junior to our existing and future secured indebtedness, including indebtedness under our revolving credit facility, to the extent of our assets constituting collateral securing that indebtedness; and

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effectively junior to all existing and future indebtedness and other liabilities (other than indebtedness and liabilities owed to us) of our non-guarantor subsidiaries.

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|---|---|
| Optional Redemption | On or after February 15, 2013, we may redeem the notes, in whole or in part, at the redemption prices described under Description of Notes Optional Redemption. |

Prior to February 15, 2011, we may on one or more occasions redeem up to 35% of the aggregate principal amount of the notes with the net cash proceeds of certain equity offerings, at a redemption price equal to 112.0% of the aggregate principal amount of the notes plus accrued and unpaid interest.

In addition, prior to February 15, 2013, we may redeem all or part of the notes at a redemption price equal to 100% of the aggregate principal amount of the notes to be redeemed, plus a make-whole premium and accrued and unpaid interest.

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|---|---|
| Change of Control Offer and Assets Sales | If we experience certain kinds of changes of control or if we sell certain assets and do not apply the proceeds as required, we will be required to offer to repurchase the notes at prices described under Description of Notes Repurchase at the Option of Holders. |
| Certain Covenants | The old notes were issued under an indenture between PDC and The Bank of New York, as trustee. The indenture will also govern the new notes. The indenture contains covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to: |

- make investments;
- incur additional indebtedness or issue preferred stock;
- create liens;
- sell assets;
- enter into agreements that restrict dividends or other payments by restricted subsidiaries;
- consolidate, merge or transfer all of substantially all of the assets of our company;
- engage in transactions with our affiliates;
- pay dividends or make other distributions on capital stock or subordinated indebtedness; and

create unrestricted subsidiaries.

These covenants are subject to a number of important limitations and exceptions that are described later in this prospectus under the caption Description of Notes Covenants.

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|---|---|
| Use of Proceeds | We will not receive any proceeds from the exchange of the outstanding old notes for the new notes. See Use of Proceeds. |
| Transfer Restrictions; Absence of a Public Market for the Notes | The new notes generally will be freely transferable, but will also be new securities for which there is no established public trading market. We cannot assure you that: |

- an active public market for the new notes will develop;
- any market that may develop for the new notes will be liquid; or
- holders will be able to sell the new notes at all or at favorable prices.

Future trading prices of the new notes will depend on many factors, including among other things, prevailing interest rates, our operating results, our credit rating and the market for similar securities. We do not intend to apply for a listing of the old notes or the new notes on any securities exchange or for inclusion of the old notes or the new notes in any automated dealer quotation system.

| | |
|---|---|
| Risk Factors | Investing in the new notes involves risks. See Risk Factors beginning on page 13 of this prospectus for a description of risks you should consider before exchanging outstanding old notes for new notes. |

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**Summary Consolidated Historical Financial Information**

The following table shows summary consolidated historical financial information as of and for the years ended December 31, 2005, 2006, and 2007 and as of and for the three months ended March 31, 2007 and 2008. The financial information for each of the three years ended December 31, 2007 was derived from our audited financial statements that are included herein. The financial information as of March 31, 2008 and for the three months ended March 31, 2008 and 2007 was derived from our unaudited consolidated financial statements. In the opinion of management, the unaudited consolidated financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the financial condition and results of operations for these periods. Operating results for the three months ended March 31, 2008 and 2007 are not necessarily indicative of the results that may be expected for any full fiscal year. Our historical results are not necessarily indicative of results to be expected in future periods. The summary consolidated historical financial information below should be read together with, and is qualified in its entirety by reference to, our consolidated historical financial statements and the accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations, included in this prospectus.

| | Year Ended December 31, | | | Three Months Ended March 31, | |
|---|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2007 | 2008 |
| | | | | *(unaudited)* | |
| | *(in thousands, except ratios)* | | | | |
| **Income Statement Information:** | | | | | |
| Revenues | $ 325,198 | $ 286,503 | $ 305,235 | $ 57,912 | $ 58,099 |
| Costs and expenses | 267,420 | 232,701 | 277,719 | 54,287 | 75,568 |
| Gain on sale of leaseholds | 7,669 | 328,000 | 33,291 | | |
| Income (loss) from operations | 65,447 | 381,802 | 60,807 | 3,625 | (17,469) |
| Interest income | 898 | 8,050 | 2,662 | 1,143 | 271 |
| Interest expense | (217) | (2,443) | (9,279) | (831) | (4,932) |
| Income (loss) before income taxes | 66,128 | 387,409 | 54,190 | 3,937 | (22,130) |
| Provision (benefit) for income taxes | 24,676 | 149,637 | 20,981 | 1,436 | (8,202) |
| Net income (loss) | $ 41,452 | $ 237,772 | $ 33,209 | $ 2,501 | $ (13,928) |
| **Other Financial Information:** | | | | | |
| Net cash provided by (used in) operating activities | $ 112,372 | $ 67,390 | $ 60,304 | $ (32,738) | $ 48,789 |
| Net cash used in investing activities | $ (94,042) | $ (9,626) | $ (267,421) | $ (23,029) | $ (64,117) |
| Net cash (used in) provided by financing activities | $ (5,290) | $ 46,452 | $ 97,542 | $ (76,983) | $ (43,221) |
| Ratio of earnings to fixed charges[(1)] | 209.6x | 93.2x | 5.0x | | (2) |

| | Year Ended December 31, | | | Three Months Ended March 31, |
|---|---|---|---|---|
| | 2005 | 2006 | 2007 | 2008 |
| | | | | *(unaudited)* |
| | *(in thousands)* | | | |
| **Balance Sheet Information (end of period):** | | | | |
| Cash and cash equivalents | $ 90,110 | $ 194,326 | $ 84,751 | $ 26,202 |
| Total assets | $ 444,361 | $ 884,287 | $ 1,050,479 | $ 1,075,467 |
| Total current liabilities | $ 180,740 | $ 241,834 | $ 242,005 | $ 277,168 |
| Total debt | $ 24,000 | $ 117,000 | $ 235,000 | $ 203,000 |
| Total liabilities | $ 256,096 | $ 524,143 | $ 654,194 | $ 695,182 |
| Stockholders equity | $ 188,265 | $ 360,144 | $ 395,526 | $ 379,542 |

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

(2) Earnings for the period were insufficient to cover fixed charges by $22.1 million.

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## RISK FACTORS

*An investment in the notes is subject to numerous risks, including those listed below. You should carefully consider the following risks, along with the information provided elsewhere in this prospectus. These risks could materially affect our ability to meet our obligations under the notes. You could lose all or part of your investment in and fail to achieve the expected return on the notes.*

### Risks Related to Our Business and the Natural Gas 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 obligations under the notes.***

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. As a result of these material weaknesses, our management concluded that our disclosure controls and procedures were not effective as of December 31, 2007 and as of March 31, 2008.

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 the notes, 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 the value of our reserves and on our cash flow. 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

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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:

- 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.

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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) and future estimated costs. 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. 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.

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

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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 and those of the partnerships we form for investors, 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.

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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.

***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. 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 and ability to repay or refinance the notes.***

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

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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.

***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.

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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.

***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

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of the technologies we use now or in the future were to become obsolete or if we were unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

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

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

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

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

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

Illustrative of these risks are regulations currently proposed by the State of Colorado which target the oil and gas industry. These multi-faceted proposed regulations significantly enhance requirements regarding oil and gas permitting, environmental requirements, and wildlife protection. The wildlife protection requirements, in particular, could require an intensive wildlife survey prior to any drilling, and may further entirely prohibit drilling for extended periods during certain wildlife breeding seasons. Many landowners and energy companies are strenuously opposing these proposed regulatory changes, and it is impossible at this time to assess the form of the final regulations or the cost to our company. Significant permitting delays and increased costs could result from any final regulations.

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

Recent litigation has commenced against us and several other companies in our industry regarding royalty practices and payments in jurisdictions where we conduct business. We intend to defend ourselves vigorously in these cases. 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 Related to the Notes and 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.

***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 the 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 the notes or any other debt securities we may offer.

***The indenture governing the notes and our senior credit agreement impose (and we anticipate that the indentures governing any other debt securities we may offer 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 the notes and our senior credit agreement contain (and we anticipate that the indentures governing any other debt securities we may offer 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;

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- 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 the notes and any other debt securities we may offer and/or the senior credit agreement. If there were an event of default under the indenture and/or the senior credit agreement, the affected creditors could cause all amounts borrowed under these instruments to be due and payable immediately. Additionally, if we fail to repay indebtedness under our senior credit agreement when it becomes due, the lenders under the senior credit agreement could proceed against the assets which we have pledged to them as security. Our assets and cash flow might not be sufficient to repay our outstanding debt in the event of a default.

The 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.

***The notes are unsecured and effectively junior to our secured indebtedness.***

The notes are not secured. Our obligations under the senior credit agreement are secured by substantially all of our assets. If we become insolvent or are liquidated, or if payment under the senior credit agreement or any of our other future secured debt obligations is accelerated, the lenders under our senior credit agreement would be entitled to exercise the remedies available to a secured lender under applicable law and the terms of our senior credit agreement and will have a claim on the assets used as collateral. The notes are therefore effectively junior to our existing and future secured indebtedness to the extent of the value of the assets securing that indebtedness. As a result, the holders of the notes may recover ratably less than the lenders of our secured debt in the event of a bankruptcy or liquidation.

***Your right to receive payments on the notes will be effectively subordinated to the rights of creditors of our subsidiaries that do not guarantee the notes or whose guarantees are invalidated.***

Initially, the notes will not be guaranteed by any of our subsidiaries. Creditors of our subsidiaries that do not guarantee the notes will have claims, with respect to the assets of those subsidiaries, that rank effectively senior to the notes. In the event of any distribution or payment of assets of such subsidiaries in any dissolution, winding up, liquidation, reorganization or other bankruptcy proceeding, the claims of those creditors must be satisfied prior to making any such distribution or payment to us in respect of its direct or indirect equity interests in such subsidiaries. Accordingly, after satisfaction of the claims of such creditors, there may be little or no amounts left available to make payments in respect of the notes. Also, as described below, there are federal and state laws that could invalidate any guarantee of our subsidiary or subsidiaries that guarantee the notes. If that were to occur, the claims of creditors of a guaranteeing subsidiary would also rank effectively senior to the notes, to the extent of the assets of that subsidiary.

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***Federal and state statutes allow courts, under specific circumstances, to void guarantees and require note holders to return payments received from guarantors.***

Under U.S. federal bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee could be voided, or claims in respect of a guarantee could be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time it incurred the indebtedness evidenced by its guarantee:

- received less than reasonably equivalent value or fair consideration for the incurrence of such guarantee; and
- was insolvent or rendered insolvent by reason of such incurrence; or
- was engaged in a business or transaction for which the guarantor s remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay such debts as they mature.

In addition, any payment by that guarantor pursuant to its guarantee could be voided and required to be returned to the guarantor, or to a fund for the benefit of the creditors of the guarantor. In any such case, your right to receive payments in respect of the notes from any such guarantor would be effectively subordinated to all indebtedness and other liabilities of that guarantor.

The measures of insolvency for purposes of these fraudulent transfer laws will vary depending upon the law applied in any proceeding to determine whether a fraudulent transfer has occurred. Generally, however, a guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all of its assets; or
- if the present fair saleable value of its assets was less than the amount that would be required to pay its probable liability on its existing debts, including contingent liabilities, as they become absolute and mature; or
- it could not pay its debts as they become due.

***We may not be able to finance a change of control offer required by the indenture governing the notes.***

If we were to experience a change of control, the indenture governing the notes will require us to offer to purchase all the notes then outstanding at 101% of their principal amount, plus unpaid accrued interest to the date of repurchase. If a change of control were to occur, we cannot assure you that we would have sufficient funds to purchase the notes. In addition, our senior credit agreement restricts our ability to repurchase the notes, even when we are required to do so by the indenture in connection with a change of control. A change in control could therefore result in a default under the senior credit agreement and could cause the acceleration of our debt. The inability to repay such debt, if accelerated, and to purchase all of the tendered notes following a change of control, would constitute an event of default under the indenture.

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## USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement that we entered into with the initial purchasers of the old notes. We will not receive any proceeds from the issuance of the new notes. In exchange for issuing the new notes, we will receive a like principal amount of old notes. The old notes surrendered in exchange for the new notes will be retired and cancelled and will not be reissued. Accordingly, issuing the new notes will not result in any increase or decrease in our outstanding debt.

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## SELECTED CONSOLIDATED HISTORICAL FINANCIAL INFORMATION

The following table shows selected consolidated historical financial information as of and for the years ended December 31, 2003, 2004, 2005, 2006 and 2007 and as of and for the three months ended March 31, 2007 and 2008. The financial information for each of the five years ended December 31, 2007 was derived from our audited financial statements. The financial information as of March 31, 2008 and for the three months ended March 31, 2008 and 2007 was derived from our unaudited consolidated financial statements. In the opinion of management, the unaudited consolidated financial statements include all adjustments, consisting only of normal recurring adjustments, necessary for a fair presentation of the financial condition and results of operations for these periods. Operating results for the three months ended March 31, 2008 and 2007 are not necessarily indicative of the results that may be expected for any full fiscal year. Our historical results are not necessarily indicative of results to be expected in future periods. The selected consolidated historical financial information below should be read together with, and is qualified in its entirety by reference to, our consolidated historical financial statements and the accompanying notes and Management s Discussion and Analysis of Financial Condition and Results of Operations, included in this prospectus.

| | Year Ended December 31, | | | | | Three Months Ended March 31, | |
|---|---|---|---|---|---|---|---|
| | 2003 | 2004 | 2005 | 2006 | 2007 | 2007 | 2008 |
| | | | | | | *(unaudited)* | |
| | *(in thousands)* | | | | | | |
| **Income Statement Information** | | | | | | | |
| Revenues: | | | | | | | |
| Oil and gas well drilling operations | $ 57,510 | $ 94,076 | $ 99,963 | $ 17,917 | $ 12,154 | $ 4,030 | $ 3,083 |
| Gas sales from marketing activities | 73,132 | 94,627 | 121,104 | 131,325 | 103,624 | 21,987 | 23,325 |
| Oil and gas sales | 48,394 | 69,492 | 102,559 | 115,189 | 175,187 | 34,016 | 71,646 |
| Well operations and pipeline income | 6,907 | 7,677 | 8,760 | 10,704 | 9,342 | 3,298 | 2,352 |
| Oil and gas price risk management gains (losses), net | (812) | (3,085) | (9,368) | 9,147 | 2,756 | (5,645) | (42,310) |
| Other income | 3,338 | 1,696 | 2,180 | 2,221 | 2,172 | 226 | 3 |
| Total revenues | 188,469 | 264,483 | 325,198 | 286,503 | 305,235 | 57,912 | 58,099 |
| Costs and expenses: | | | | | | | |
| Cost of oil and gas well drilling operations | 46,946 | 77,696 | 88,185 | 12,617 | 2,508 | 564 | 78 |
| Cost of gas marketing activities | 72,361 | 92,881 | 119,644 | 130,150 | 100,584 | 21,512 | 22,121 |
| Oil and gas production and well operations costs | 13,630 | 17,713 | 20,400 | 29,021 | 49,264 | 9,035 | 18,132 |
| Exploration cost | | | 11,115 | 8,131 | 23,551 | 2,678 | 4,283 |
| General and administrative expense | 4,975 | 4,506 | 6,960 | 19,047 | 30,968 | 7,424 | 9,823 |
| Depreciation, depletion and amortization | 15,313 | 18,156 | 21,116 | 33,735 | 70,844 | 13,074 | 21,131 |
| Total costs and expenses | 153,225 | 210,952 | 267,420 | 232,701 | 277,719 | 54,287 | 75,568 |
| Gain on sale of leaseholds | | | 7,669 | 328,000 | 33,291 | | |
| Income (loss) from operations | 35,244 | 53,531 | 65,447 | 381,802 | 60,807 | 3,625 | (17,469) |
| Interest income | 190 | 185 | 898 | 8,050 | 2,662 | 1,143 | 271 |
| Interest expense | (816) | (238) | (217) | (2,443) | (9,279) | (831) | (4,932) |
| Income (loss) before income taxes and cumulative effect of change in accounting principle | 34,618 | 53,478 | 66,128 | 387,409 | 54,190 | 3,937 | (22,130) |
| Provision (benefit) for income taxes | 11,934 | 20,250 | 24,676 | 149,637 | 20,981 | 1,436 | (8,202) |
| Income before cumulative effect of change in accounting principle | 22,684 | 33,228 | 41,452 | 237,772 | 33,209 | 2,501 | (13,928) |
| Cumulative effect of change in accounting principle (net of taxes of $1,392) | (2,271) | | | | | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Net income | $ 20,413 | $ 33,228 | $ 41,452 | $ 237,772 | $ 33,209 | $ 2,501 | $ (13,928) |

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| | Year Ended December 31, | | | | | Three Months Ended March 31, | |
|---|---|---|---|---|---|---|---|
| | 2003 | 2004 | 2005 | 2006 | 2007 | 2007 | 2008 |
| | | | | | | *(unaudited)* | |
| | *(in thousands)* | | | | | | |
| **Other Financial Information:** | | | | | | | |
| Net cash provided by (used in) operating activities | $ 74,502 | $ 73,301 | $ 112,372 | $ 67,390 | $ 60,304 | $ (32,738) | $ 48,789 |
| Net cash provided by (used in) investing activities | $ (71,503) | $ (43,346) | $ (94,042) | $ (9,626) | $ (267,421) | $ (23,029) | $ (64,117) |
| Net cash provided by (used in) financing activities | $ 27,251 | $ (31,398) | $ (5,290) | $ 46,452 | $ 97,542 | $ (76,983) | $ (43,221) |

| | Year Ended December 31, | | | | | Three Months Ended March 31, |
|---|---|---|---|---|---|---|
| | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 |
| | | | | | | *(unaudited)* |
| | *(in thousands)* | | | | | |
| **Balance Sheet Information (end of period):** | | | | | | |
| Cash and cash equivalents | $ 78,513 | $ 77,070 | $ 90,110 | $ 194,326 | $ 84,751 | $ 26,202 |
| Total assets | $ 294,004 | $ 329,453 | $ 444,361 | $ 884,287 | $ 1,050,479 | $ 1,075,467 |
| Total current liabilities | $ 103,428 | $ 119,531 | $ 180,740 | $ 241,834 | $ 242,005 | $ 277,168 |
| Total debt | $ 53,000 | $ 21,000 | $ 24,000 | $ 117,000 | $ 235,000 | $ 203,000 |
| Total liabilities | $ 181,445 | $ 175,432 | $ 256,096 | $ 524,143 | $ 654,194 | $ 695,182 |
| Stockholders equity | $ 112,559 | $ 154,021 | $ 188,265 | $ 360,144 | $ 395,526 | $ 379,542 |

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## MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION

## AND RESULTS OF OPERATIONS

*The following discussion of financial condition and results of operations should be read in conjunction with our historical financial statements and the accompanying notes included in this prospectus. The following discussion contains, in addition to historical information, forward-looking statements that are subject to significant risks and uncertainties. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of various factors, including those factors set forth under the captions Special Note Regarding Forward-Looking Statements and Risk Factors and elsewhere in this prospectus.*

**Overview**

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 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.

During the second quarter of 2007, we dismissed KPMG as our independent registered public accounting firm, and engaged the independent registered public accounting firm of PricewaterhouseCoopers LLP. This change is effective with respect to the current fiscal year ending December 31, 2007. The replacement of our independent registered public accountants was not the result of any disagreement as to any audit-related issues.

In the third quarter of 2006, we sold undeveloped property in the Grand Valley Field for a gain of $328.0 million, with approximately $25.6 million in additional gains recognized in the second quarter of 2007.

In 2005, we restated our results of operations for the quarterly periods ending March 31, 2005, June 30, 2005, and September 30, 2005, and the years ended December 31, 2004, 2003, 2002 and 2001. The restatement was made to correct errors in the reporting of certain revenues and expenses to properly reflect the elimination of transactions between us and our drilling partnerships. The corrections resulted in the elimination of revenues and expenses of equal amounts. The restatement had no effect on net income, earnings per share, cash flows, proved oil and gas reserves, or our financial position.

Net loss for the three months ended March 31, 2008, was $13.9 million compared to net income of $2.5 million for the same prior year period. The primary reason for the loss during the first quarter of 2008 compared to 2007 was due to the unrealized losses on derivatives of $39.9 million compared to $6.2 million for the same prior year period. Rapid increases during the first quarter of 2008 to record high oil prices and sharp increases in natural gas prices from December 31, 2007, to March 31, 2008, along with our increased use of derivative contracts and specifically more fixed price swaps caused the increase in realized and unrealized losses in oil and gas price risk management loss, net. See *Oil and Gas Price Risk Management Loss, Net* discussion below for a detailed discussion of realized and unrealized losses on oil and gas derivative activity. The major offsetting factors, which somewhat mitigated the non-cash unrealized derivative loss, were the effect on oil and gas sales due to significantly increased production and commodity prices realized during the period.

Our total oil and natural gas production increased by 3.1 Bcfe or approximately 59% during the quarter ended March 31, 2008, compared to the quarter ended March 31, 2007. During this same time period, the average

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sales price per Mcfe increased by approximately 32% from $6.38 per Mcfe during the quarter ended March 31, 2007, to $8.45 per Mcfe during the quarter ended March 31, 2008. See our oil and gas production table below under *Oil and Gas Sales*.

Total revenues for the three months ended March 31, 2008, were $58.1 million compared to $57.9 million for the same prior year period. The two offsetting items for the quarter ended March 31, 2008, compared with 2007 were oil and gas sales and oil and gas price risk management loss, net. Our total oil and gas sales increased from $34 million for the three months ended March 31, 2007, to $71.6 million for the three months ended March 31, 2008, an increase of $37.6 million or 111%. The increase was driven by an increase in production of 59% and an increase in realized oil and natural gas prices of 32%.

The $37.6 million increase in oil and gas sales was almost entirely offset by an increase in oil and gas price risk management loss, net of $36.7 million for the three months ended March 31, 2008, compared with the prior year first quarter. Of the $42.3 million oil and gas price risk management loss for the first quarter of 2008, $39.9 million resulted from non-cash unrealized losses resulting from significant increases in oil and gas commodity prices from December 31, 2007, to March 31, 2008, on open derivative positions.

Costs and expenses for the three months ended March 31, 2008, were $75.6 million compared to $54.3 million for the same prior year period, an increase of $21.3 million or 39.2%. The increase was primarily the result of increases in oil and gas production and well operations cost, general and administrative expense and depreciation, depletion and amortization.

The 59% or 3.1 Bcfe increase in production for the first quarter of 2008 compared to the same prior year period was the primary contributor to the increases in oil and gas production and well operations cost and depreciation, depletion and amortization. The increase in general and administrative expense is primarily due to expenses associated with the separation agreement executed with our former president upon his resignation.

While we benefit significantly from the rising energy prices in our oil and gas sales, the rising energy prices bring about inflationary factors that affect our costs and expenses. The increase in energy prices has affected demand for drilling and completion services, land acquisitions, and the cost of experienced industry personnel. The cost of steel used for tubular goods and surface equipment has increased dramatically over the past several years and represents approximately 20% to 30% of the total cost of a new well. We expect this inflationary trend to continue as energy prices rise. We consume great quantities of fuel in the use of drilling rigs, service rigs, vehicles used for hauling materials, such as surface casing, tubular goods and water, as well as, vehicles used for well tending and general operations.

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**

***Three Months Ended March 31, 2008, Compared to Three Months Ended March 31, 2007***

***Revenues***

*Oil and Gas Sales*

| | Three Months Ended March 31, | | Change | |
|---|---|---|---|---|
| | 2008 | 2007 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Oil and gas sales | $ 71,646 | $ 34,016 | $ 37,630 | 110.6% |

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Oil and gas sales from our producing properties for the three months ended March 31, 2008, were $71.6 million compared to $34.0 million for the same prior year period, an increase of $37.6 million or approximately 111%. The increase was due to increased volumes of natural gas and oil along with increased average sales prices of natural gas and oil.

Increased volumes of oil and natural gas produced contributed $25.1 million to oil and gas sales revenue for the current quarter and significantly increased commodity prices contributed the remaining $12.5 million increase in oil and gas sales revenue, for a total increase in oil and natural gas sales revenue of $37.6 million for the first quarter of 2008 compared to the same prior year period. The volume of natural gas sold for the three months ended March 31, 2008, was 6.9 Bcf at an average sales price of $7.33 per Mcf compared to 4.1 Bcf at an average sales price of $6.05 per Mcf for the three months ended March 31, 2007. Oil sales were 255,500 barrels at an average sales price of $81.14 per barrel for the three months ended March 31, 2008, compared to 199,500 barrels at an average sales price of $45.06 per barrel for the three months ended March 31, 2007. The increase in oil and natural gas volumes resulted from acquisitions of producing oil and gas properties and a significant increase in the number of wells drilled for our own account over the past year.

*Oil and Gas Production*. Our oil and natural gas production by area of operations along with average sales price (excluding derivative gains/losses) is presented below:

| | Three Months Ended March 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2008 | | | 2007 | | | Change | | |
| | Oil *(Bbls)* | Natural Gas *(Mcf)* | Natural Gas Equivalent *(Mcfe)* | Oil *(Bbls)* | Natural Gas *(Mcf)* | Natural Gas Equivalent *(Mcfe)* | Oil | Natural Gas | Total |
| Production | | | | | | | | | |
| Appalachian Basin | 1,096 | 967,620 | 974,196 | 1,374 | 609,397 | 617,641 | 20% | 59% | 58% |
| Michigan Basin | 823 | 379,437 | 384,375 | 815 | 420,887 | 425,777 | 1% | 10% | 10% |
| Rocky Mountain Region | 253,533 | 5,599,765 | 7,120,963 | 197,350 | 3,105,669 | 4,289,769 | 28% | 80% | 66% |
| Total | 255,452 | 6,946,822 | 8,479,534 | 199,539 | 4,135,953 | 5,333,187 | 28% | 68% | 59% |

| | Three Months Ended March 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2008 | | | 2007 | | | Change | | |
| | Oil | Natural Gas | Total | Oil | Natural Gas | Total | Oil | Natural Gas | Total |
| | *(dollars in thousands, except average price)* | | | | | | | | |
| Sales | | | | | | | | | |
| Appalachian Basin | $ 97 | $ 8,138 | $ 8,235 | $ 69 | $ 4,052 | $ 4,121 | 41% | 101% | 100% |
| Michigan Basin | 79 | 2,895 | 2,974 | 40 | 2,568 | 2,608 | 98% | 13% | 14% |
| Rocky Mountain Region | 20,551 | 39,886 | 60,437 | 8,882 | 18,408 | 27,290 | 131% | 117% | 121% |
| Total | $ 20,727 | $ 50,919 | $ 71,646 | $ 8,991 | $ 25,028 | $ 34,019 | 131% | 103% | 111% |
| Average Sales Price *(Oil per Bbl, Natural Gas per Mcf, Total per Mcfe)* | | | | | | | | | |
| Appalachian Basin | $ 88.71 | $ 8.41 | $ 8.45 | $ 50.59 | $ 6.65 | $ 6.67 | 75% | 26% | 27% |
| Michigan Basin | 96.03 | 7.63 | 7.74 | 49.02 | 6.10 | 6.12 | 96% | 25% | 26% |
| Rocky Mountain Region | 81.08 | 7.13 | 8.49 | 45.02 | 5.92 | 6.36 | 80% | 20% | 33% |
| Total | $ 81.14 | $ 7.33 | $ 8.45 | $ 45.06 | $ 6.05 | $ 6.38 | 80% | 21% | 32% |

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Late in June 2007, we placed into service the upgraded Garden Gulch pipeline and compressor facility, which serves a majority of our wells in the Piceance Basin of our Rocky Mountain Region. 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 our wells feeding this facility.

*Oil and Gas Pricing*. Financial results depend upon many factors, particularly the price of oil and 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. Oil and natural gas 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 have resulted 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, was a decrease in the price of Rocky Mountain natural gas compared to the New York Mercantile Exchange, or NYMEX, price and other markets as shown in the graph below. The expansion in January 2008 of the Rockies Express pipeline, a major interstate pipeline constructed and operated by a non-affiliated entity, is the primary reason for the narrowing of the NYMEX/Colorado Interstate Gas, or CIG, gap from November 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. Oil pricing is also driven strongly by supply and demand relationships. In the Rocky Mountain Region in 2007, and the first quarter of 2008, the oil prices we received were below the NYMEX oil market due to supply competition from Rocky Mountain and Canadian oil that has driven down market prices. Beginning in the middle of the second quarter of 2008, through the end of 2010, we have contracted the majority of our oil sales at a price with a smaller spread below NYMEX.

*Rocky Mountain Region Pricing*. 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 CIG prices. The CIG Index, and other indices for production delivered to other Rocky Mountain pipelines, has historically been less than the price received for natural gas produced in the eastern regions, which is NYMEX based.

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The graph below identifies the actual NYMEX and CIG natural gas prices by month from January 2006 through April 2008 and the forward curve for natural gas prices from May 2008 through November 2009 as of April 21, 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 nineteen 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.

* Source: Derived from various sources including FutureSource, Inside Federal Energy Regulatory Commission s, or FERC, Gas Market Report and ClearPort Trading.

While the above graph shows a large differential between 2007 NYMEX and CIG pricing, the gap began narrowing in November 2007 and has continued to narrow. As of April 21, 2008, the negative price differential between NYMEX and CIG for 2008 has narrowed to $1.93 from $3.38 average for the fourth quarter of 2007. Although 80.6% of our first quarter 2008 natural gas production came from the Rocky Mountain Region, our Rocky Mountain natural gas pricing is based upon other indices in addition to CIG.

The table below identifies the pricing basis of our oil and natural gas pricing for sales volumes during the quarter ended March 31, 2008. The pricing basis is the index that most closely relates to the contract under which the oil and natural gas is sold. As it indicates, 40% of our natural gas sales are derived from the CIG Index and other similarly priced Rocky Mountain pipelines.

**Energy Market Exposure**

**For the Three Months Ended March 31, 2008**

| Area | Pricing Basis | Commodity | Percent of Oil and Gas Sales |
|---|---|---|---|
| Piceance/Wattenberg | Rocky Mountain (CIG, et. al.) | Gas | 40.0% |
| NECO | Mid Continent (Panhandle Eastern) | Gas | 26.0% |
| Colorado/North Dakota | NYMEX | Oil | 16.0% |
| Appalachian | NYMEX | Gas | 11.0% |
| Michigan | Mich-Con/NYMEX | Gas | 5.0% |
| Wattenberg | Colorado Liquids | Gas | 2.0% |
| | | | 100.0% |

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*Natural Gas Marketing Activities*

| | Three Months Ended March 31, 2008 | 2007 | Change Amount | Percent |
|---|---|---|---|---|
| | | (dollars in thousands) | | |
| Sales from natural gas marketing activities | 23,325 | 21,987 | 1,338 | 6.1% |

The increase in sales from natural gas marketing activities in 2008 is primarily due to an increase in prices and volumes sold, partially offset by a $4.3 million increase in unrealized losses on derivative transactions from a $3.3 million loss in 2007 to a $7.6 million loss in 2008.

Our natural gas marketing segment specializes in the purchase, aggregation and sale of natural gas production in our eastern operating areas. Through our natural gas marketing segment, we market the natural gas we produce as well as our purchases of natural gas from other producers in the Appalachian Basin, including our affiliated partnerships. Our derivative activities related to natural gas marketing activities include both physical and cash-settled derivatives. We offer fixed-price derivative contracts for the purchase or sale of physical gas and enter into cash-settled derivative positions with counterparties in order to offset those same physical positions. We do not take speculative positions on commodity prices.

***Oil and Gas Price Risk Management Loss, Net***

| | Three Months Ended March 31, 2008 | 2007 | Change Amount | Percent |
|---|---|---|---|---|
| | | (dollars in thousands) | | |
| Oil and gas price risk management: | | | | |
| Realized gain (loss): | | | | |
| Oil | $ (1,306) | $ (52) | $ (1,254) | * |
| Natural gas | (1,105) | 632 | (1,737) | * |
| Total realized gain (loss) | (2,411) | 580 | (2,991) | * |
| Unrealized loss | (39,899) | (6,225) | (33,674) | * |
| Oil and gas price risk management loss, net | $ (42,310) | $ (5,645) | $ (36,665) | * |

* Represents percentages in excess of 250%.

The rapid increases during the first quarter of 2008 to record high oil prices and sharp increases in natural gas prices from December 31, 2007, to March 31, 2008, along with our increased use of derivative contracts and specifically more fixed price swaps caused the increase in realized and unrealized losses in oil and gas price risk management loss, net. The $39.9 million in unrealized losses for the three months ended March 31, 2008, is the fair value of the derivative positions as of March 31, 2008, less the fair value as of December 31, 2007, and includes all open positions as of March 31, 2008, for the entire period from April 2008 until the expiration of the last position, which is February 2011. The unrealized loss is a non-cash item in the first quarter of 2008 and there will be further gains or losses as prices increase or decrease until the positions are closed. While the required accounting treatment for derivatives that do not qualify for hedge accounting treatment under SFAS No. 133 results in significant swings in value and resulting gains and losses for reporting purposes over the life of the derivatives, the combination of the settled derivative contracts and the revenue received from the oil and gas sales at delivery are expected to result in a more predictable cash flow stream than would the sales contracts without the associated derivatives.

Oil and gas price risk management loss, net includes realized gains and losses 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 loss, net does not include commodity based derivative transactions related to transactions from

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natural gas marketing activities, which are included in sales from and cost of natural gas marketing activities. See Notes 4 and 5 to the accompanying condensed consolidated financial statements for additional details of our derivative financial instruments.

*Oil and Gas Derivative Activities*. Because of uncertainty surrounding oil and natural gas prices we have used various derivative instruments to manage some of the impact of fluctuations in prices. Through February 2011, we have in place a series of floors, ceilings, collars and fixed price swaps on a portion of our oil and natural gas 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. During the three months ended March 31, 2008, we averaged natural gas volumes sold of 2.3 Bcf per month and oil sales of 85,000 barrels per month.

The following table sets forth our derivative positions in effect as of May 12, 2008, on our share of production by area.

| Commodity/ Index/Area | Month Set | Month | Gross Monthly Quantity Gas-MMbtu Oil-Bbls | Floors Net Monthly Quantity Gas-MMbtu Oil-Bbls | Floors Floor Price | Ceilings Net Monthly Quantity Gas-MMbtu Oil-Bbls | Ceilings Ceiling Price | Swaps (Fixed Prices) Net Monthly Quantity Gas-MMbtu Oil-Bbls | Swaps (Fixed Prices) Price |
|---|---|---|---|---|---|---|---|---|---|
| **Natural Gas Colorado Interstate Gas (CIG) Based Derivatives Piceance Basin** | | | | | | | | | |
| | Feb-08 | Apr 08 Oct 08 | 750,000 | | $ | | $ | 454,650 | $ 7.05 |
| | Jan-08 | Apr 08 Oct 08 | 630,000 | | | | | 381,906 | 6.54 |
| | Apr-08 | Nov 08 Mar 09 | 570,000 | | | | | 345,534 | 7.76 |
| | Feb-08 | Nov 08 Mar 09 | 340,000 | 206,108 | 7.00 | 206,108 | 9.70 | | |
| | Feb-08 | Nov 08 Mar 09 | 340,000 | | | | | 206,108 | 8.18 |
| | Jan-08 | Apr 09 Oct 09 | 570,000 | 345,534 | 5.75 | 345,534 | 8.75 | | |
| | Mar-08 | Apr 09 Oct 09 | 560,000 | 339,472 | 5.75 | 339,472 | 9.05 | | |
| **Wattenberg Field** | | | | | | | | | |
| | Feb-08 | Apr 08 Oct 08 | 450,000 | | | | | 321,480 | 7.05 |
| | Jan-08 | Apr 08 Oct 08 | 290,000 | | | | | 211,460 | 6.54 |
| | Apr-08 | Nov 08 Mar 09 | 320,000 | | | | | 241,460 | 7.76 |
| | Feb-08 | Nov 08 Mar 09 | 180,000 | 133,590 | 7.00 | 133,590 | 9.70 | | |
| | Feb-08 | Nov 08 Mar 09 | 180,000 | | | | | 133,590 | 8.18 |
| | Jan-08 | Apr 09 Oct 09 | 320,000 | 241,460 | 5.75 | 241,460 | 8.75 | | |
| | Mar-08 | Apr 09 Oct 09 | 290,000 | 218,600 | 5.75 | 218,600 | 9.05 | | |
| **Natural Gas Panhandle Based Derivatives NECO** | | | | | | | | | |
| | Feb-08 | Apr 08 Oct 08 | 180,000 | | | | | 180,000 | 7.45 |
| | Jan-08 | Apr 08 Oct 08 | 120,000 | | | | | 120,000 | 6.80 |
| | Apr-08 | Nov 08 Mar 09 | 110,000 | | | | | 110,000 | 8.09 |
| | Feb-08 | Nov 08 Mar 09 | 80,000 | 80,000 | 7.25 | 80,000 | 10.05 | | |
| | Feb-08 | Nov 08 Mar 09 | 80,000 | | | | | 80,000 | 8.44 |
| | Jan-08 | Apr 09 Oct 09 | 110,000 | 110,000 | 6.00 | 110,000 | 9.70 | | |
| | Mar-08 | Apr 09 Oct 09 | 130,000 | 130,000 | 6.25 | 130,000 | 11.75 | | |
| **Natural Gas NYMEX Based Derivatives Appalachian and Michigan Basins** | | | | | | | | | |
| | Feb-08 | Apr 08 Oct 08 | 170,000 | | | | | 124,763 | 8.33 |
| | Feb-08 | Apr 08 Oct 08 | 170,000 | | | | | 124,763 | 8.58 |
| | Mar-08 | Nov 08 Mar 09 | 170,000 | 124,763 | 9.00 | 124,763 | 11.32 | | |
| | Feb-08 | Nov 08 Mar 09 | 100,000 | 73,390 | 8.40 | 73,390 | 13.05 | | |
| | Feb-08 | Nov 08 Mar 09 | 100,000 | | | | | 73,390 | 9.62 |
| | Jan-08 | Apr 09 Oct 09 | 170,000 | 124,763 | 6.75 | 124,763 | 12.45 | | |
| | Mar-08 | Apr 09 Oct 09 | 170,000 | 124,763 | 7.50 | 124,763 | 13.25 | | |
| | Feb-08 | Mar 08 Feb 11 | 90,000 | | | | | 90,000 | 8.62 |
| | May-08 | Apr 09 Mar 12 | 60,000 | | | | | 44,034 | 9.89 |

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| | | | | Floors | | Ceilings | | Swaps (Fixed Prices) | |
|---|---|---|---|---|---|---|---|---|---|
| | | | Gross Monthly | Net Monthly | | Net Monthly | | Net Monthly | |
| Commodity/ | | | Quantity | Quantity | | Quantity | | Quantity | |
| Index/Area | Month Set | Month | Gas-MMbtu Oil-Bbls | Gas-MMbtu Oil-Bbls | Floor Price | Gas-MMbtu Oil-Bbls | Ceiling Price | Gas-MMbtu Oil-Bbls | Price |
| **Oil NYMEX Based Wattenberg Field** | | | | | | | | | |
| | Oct-07 | Apr 08 Dec 08 | 48,667 | | | | | 31,741 | 84.20 |
| | May-08 | Jun 08 Dec 08 | 36,686 | | | | | 23,927 | 108.05 |
| | Jan-08 | Jan 09 Dec 09 | 30,417 | | | | | 19,838 | 84.90 |
| | Jan-08 | Jan 09 Dec 09 | 30,417 | | | | | 19,838 | 85.40 |
| | May-08 | Jan 10 Dec 10 | 12,167 | | | | | 7,935 | 117.35 |
| | May-08 | Jan 10 Dec 10 | 30,417 | | | | | 19,838 | 92.74 |
| | May-08 | Jan 10 Dec 10 | 30,417 | | | | | 19,838 | 93.17 |

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 will change. The gross volumes in the above table reflect the total volumes hedged for ourselves and the partnerships jointly by area of operation. The above table reflects such revisions necessary to present our positions in effect as of March 31, 2008.

***Costs and Expenses***

*Oil and Gas Production and Well Operations Cost*

Oil and gas production and well operations costs for the three months ended March 31, 2008 and 2007, are presented below.

| | Three Months Ended March 31, 2008 | 2007 | Change Amount | Percent |
|---|---|---|---|---|
| | *(dollars in thousands, except per Mcfe)* | | | |
| Oil and gas production and well operations cost | $ 18,132 | $ 9,035 | $ 9,097 | 100.7% |
| *Per Mcfe* | *$ 2.14* | *$ 1.69* | *$ 0.45* | *26.6%* |

The increase in oil and gas production and well operations cost for the year was primarily attributable to the 59% increase in production volumes and the increased number of wells and pipeline systems we operate. Lifting costs per Mcfe increased approximately 50% from $1.15 per Mcfe in the first quarter of 2007 to $1.72 per Mcfe in 2008. Included in our lifting costs are production taxes which are based upon the sales prices of the oil and natural gas sold. Since the average prices per Mcfe increased from $6.38 in the first quarter of 2007 to $8.45 for the first quarter of 2008, $.15 per Mcfe of the $.57 per Mcfe increase in lifting costs is due to the production taxes on higher oil and gas sales.

In addition to increased production, the increase in costs is also attributable to increased personnel in the production and engineering staffs, increased maintenance and operating cost of the new pipeline and compressor upgrades and improvements, increased production enhancements and workovers associated with the December 2006 and the first quarter 2007 acquisitions and significant general oil field services inflation pressures. Oil and gas production and well operations cost includes the lifting cost of our production, the cost to operate wells and pipelines for our sponsored partnerships and other third parties (whose income is included in well operations and pipeline income) and certain production and engineering staff related overhead costs.

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*Natural Gas Marketing Activities*

Cost of natural gas marketing activities for the three months ended March 31, 2008 and 2007, is presented below.

| | Three Months Ended March 31, | | Change | |
|---|---|---|---|---|
| | 2008 | 2007 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Cost of natural gas marketing activities | $ 22,121 | $ 21,512 | $ 609 | 2.8% |

The increase in the cost of natural gas marketing activities in 2008 was primarily due to an increase in prices and volumes purchased for resale, primarily offset with a $5.3 million increase in unrealized gains on derivative transactions, from a $2.9 million gain in 2007 to an $8.2 million gain in 2008.

*Exploration Expense*

Exploration expense for the three months ended March 31, 2008 and 2007, is presented below.

| | Three Months Ended March 31, | | Change | |
|---|---|---|---|---|
| | 2008 | 2007 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Exploration expense | $ 4,283 | $ 2,678 | $ 1,605 | 59.9% |

The increase in exploration expense is primarily due to an increase in staffing costs, including the use of consultants, along with additional seismic work and an increase in lease expense.

*General and Administrative Expense*

General and administrative expense for the three months ended March 31, 2008 and 2007, is presented below.

| | Three Months Ended March 31, | | Change | |
|---|---|---|---|---|
| | 2008 | 2007 | Amount | Percent |
| | *(dollars in thousands, except per Mcfe)* | | | |
| General and administrative expense | $ 9,823 | $ 7,424 | $ 2,399 | 32.3% |
| *Per Mcfe* | *$ 1.16* | *$ 1.39* | *$ (0.23)* | *16.5%* |

The increase in general and administrative expense for the three months ended March 31, 2008, was the result of expenses related to a separation agreement for our former president in the amount of $3.2 million during the first quarter of 2008. Although general and administrative expense increased $2.4 million from 2007 to 2008, the rate per Mcfe declined from $1.39 per Mcfe to $1.16 per Mcfe.

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*Depreciation, Depletion, and Amortization*

DD&A for the three months ended March 31, 2008 and 2007, is presented below.

| | Three Months Ended March 31, | | Change | |
|---|---|---|---|---|
| | 2008 | 2007 | Amount | Percent |
| | *(dollars in thousands, except per Mcfe)* | | | |
| Depreciation, depletion and amortization | $ 21,131 | $ 13,074 | $ 8,057 | 61.6% |
| *Per Mcfe* | *$ 2.49* | *$ 2.45* | *$ 0.04* | *1.6%* |

The 59% higher production volumes realized in 2008 resulted in an $8.1 million increase in DD&A expense in the quarter ended March 31, 2008, compared to 2007. The DD&A rates for oil and gas properties are shown in the table below for our significant areas of operations.

| | Three Months Ended March 31, | |
|---|---|---|
| | 2008 | 2007 |
| | *(per Mcfe)* | |
| Appalachian Basin | $ 1.47 | $ 1.27 |
| Michigan Basin | 1.30 | 1.26 |
| Rocky Mountain Region: | | |
| Wattenberg Field (1) | 3.37 | 2.90 |
| Piceance Basin | 1.81 | 2.21 |
| NECO | 1.29 | 1.40 |

(1) This field contains 93.9% and 87.5% of our oil production for the quarters ended March 31, 2008 and 2007, respectively.

The weighted average DD&A rate for oil and gas properties increased to $2.33 per Mcfe for the three months ended March 31, 2008 from $2.32 per Mcfe for the same period in 2007. Although the overall DD&A rate increased only by $.01 per Mcfe from the first quarter of 2007 to the first quarter of 2008, the upward revision in our reserve report at December 31, 2007, due to higher commodity pricing, partially offset by increased operation costs, lowered our DD&A rate per Mcfe at about the same proportion that the higher cost of well drilling, completion and equipping of new wells increased the DD&A rate. As reflected in the above table of field DD&A rates, this overall increase of $.01 per Mcfe varied greatly among our major fields depending on whether the increase in reserves out weighted the increase in costs. DD&A expense for non-oil and gas properties, which are not included in the above table, increased to $1.4 million in 2008 from $0.7 million in 2007, and consist primarily of the Garden Gulch Road, a new integrated oil and gas financial reporting system and equipment acquired in our October 2007 acquisition.

*Non-operating Income/Expense*

Non-operating income and expense for the three months ended March 31, 2008 and 2007, are presented below.

| | Three Months Ended March 31, | | Change | |
|---|---|---|---|---|
| | 2008 | 2007 | Amount | Percent |
| | *(dollars in thousands)* | | | |
| Non-operating income (expense): | | | | |
| Interest income | $ 271 | $ 1,143 | $ (872) | 76.3% |
| Interest expense | $ (4,932) | $ (831) | $ (4,101) | 493.5% |

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The decrease in interest income for the quarter is a result of lower cash balances earning interest at lower rates 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 earning interest until reinvested in oil and gas properties in mid January 2007. The increase in interest expense in 2008 was due to significantly higher average outstanding balances of our credit facility and the 12% senior notes, offset by capitalized construction period interest of $0.6 million in 2008 and $0.5 million in 2007. We utilize our daily cash balances to reduce the line of credit borrowings, lowering the cost of interest.

***Provision for Income Taxes***

The effective income tax rate for the current quarter was 37.1%, relatively unchanged from 36.5% in the same prior year quarter.

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

***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.

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.

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

| | 2007 | | | 2006 | | | Change | | |
|---|---|---|---|---|---|---|---|---|---|
| | Oil *(Bbls)* | Natural Gas *(Mcf)* | Natural Gas Equivalent *(Mcfe)* | Oil *(Bbls)* | Natural Gas *(Mcf)* | Natural Gas Equivalent *(Mcfe)* | Oil *(Bbls)* | Natural Gas *(Mcf)* | 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% |

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| | 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.

*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

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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.

* 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.

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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.

**Energy Market Exposure**

**as of December 31, 2007**

| Area | Price 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 | Michi-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, 2007 | 2006 | Change 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.

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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) | |
|---|---|---|---|---|---|---|---|
| Month Set | Months Covered | Monthly Quantity Gas-MMbtu Oil-Bbls | Contract Price | Monthly Quantity MMbtu | Contract Price | Monthly Volume MMbtu/Bbls | Price |
| **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 | April 2008 Oct 2008 | | | | | 488,900 | 7.05 |
| Jan-08 | April 2008 Oct 2008 | | | | | 410,700 | 6.54 |
| Jan-08 | Nov 2008 Mar 2009 | 371,600 | 6.50 | 371,600 | 10.15 | | |
| Feb-08 | Nov 2008 Mar 2009 | 221,650 | 7.00 | 221,650 | 9.70 | | |
| Feb-08 | Nov 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 |
| **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 | | |

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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, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | 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.

*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.

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*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 natural 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.

*General and Administrative Expense*

General and administrative 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, 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%* |

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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, | | Change | |
|---|---|---|---|---|
| | 2007 | 2006 | Amount | 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 | 2006 |
| | *(per Mcfe)* | |
| Appalachian Basin | $ 1.32 | $ 1.13 |
| 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.

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%.

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***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***

***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, | | Change | |
|---|---|---|---|---|
| | 2006 | 2005 | Amount | 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 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.

*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.

| | Year Ended December 31, | | Change | |
|---|---|---|---|---|
| | 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).

*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) | | |
| 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.

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*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, 2006 | 2005 | Change 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):

| | 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 | $ 100.00 |
| 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, 2006 | 2005 | Change 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%* |

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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.

*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. 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

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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 March 31, 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 as additional properties are developed. See *Long Term Debt* discussed below.

We establish a capital budget for each calendar year based on our development opportunities and the expected cash flow from operations for that year. Our 2008 capital expenditure budget was initially approved at $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. With higher than anticipated oil and natural gas prices and resulting increases in cash flows from operations, our Board of Directors has approved an increase in our capital expenditure budget of $40 million for a total of $295 million. The entire $40 million increase was designated for additional development drilling in our Grand Valley field of our Rocky Mountain Region. 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 schedule, which is 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, our ability to increase production and changes in costs are the principal determinants of the level of our cash flow from operations. Oil and natural gas sales in the three months ended March 31, 2008 were 111% higher than the three months ended March 31, 2007, resulting from a 32% increase in average oil and natural gas prices and a 59% increase in oil and natural gas production. 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 fixed-price swaps, as of May 12, 2008, that we estimate will largely offset price changes for approximately 70% of our expected oil production and fixed price swaps and collars on 69% of our expected natural gas production for the remainder of 2008, thereby reducing the risk of significant declines for a substantial portion of our 2008 cash flow. The remaining 30% and 31% of estimated 2008 oil and natural gas production, respectively, is unhedged and will be impacted by increasing and decreasing commodity market prices. 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 derivatives as of May 12, 2008, are detailed above in *Results of Operations Oil and Gas Price Risk Management Loss, Net: Oil and Gas Derivative Activities*.

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

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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.

Additionally, beginning August 15, 2008, we are required to pay our semi-annual interest payment on our 12% senior notes in the amount of $12.2 million. See *Contractual Obligations and Contingent Commitments* below detailing projected interest payments through maturity of the notes.

**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 our financial statement restatement and incremental costs to comply with various provisions of Sarbanes-Oxley; 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 balance fluctuates as a result of the amount of borrowings and the timing of repayments under our credit facility. Generally, to the extent that we have outstanding borrowing, we use excess cash to pay down borrowings under our credit facility. As a result, we often have a working capital deficit or a relatively small amount of positive working capital. Our working capital usage for 2007 was $50.2 million. Our working capital usage for the three months ended March 31, 2008, was $57 million, largely related to cash used in drilling

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activities. 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 March 31, 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.

**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 and $234.1 million as of March 31, 2008. 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. 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 resumed with our quarter ended March 31, 2008.

As of March 31, 2008, our credit facility was undrawn, compared to an outstanding balance of $235 million as of December 31, 2007 and $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 are secured by substantially all of our properties. We were in compliance with all covenants at March 31, 2008 and December 31, 2007, and expect to remain in compliance throughout 2008.

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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.

The following table summarizes our development and exploratory drilling activity for the first three months ended March 31, 2008 and 2007. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of producing wells and wells capable of commercial production.

| | Drilling Activity Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | 2008 | | 2007 | |
| | Gross | Net | Gross | Net |
| Development | | | | |
| Productive[1] | 92.0 | 58.8 | 54.0 | 38.4 |
| Dry | | | 2.0 | 1.4 |
| Total development | 92.0 | 58.8 | 56.0 | 39.8 |
| Exploratory | | | | |
| Productive[1] | | | | |
| Dry | 2.0 | 2.0 | 2.0 | 0.7 |
| Pending determination | 7.0 | 7.0 | 3.0 | 1.0 |
| Total exploratory | 9.0 | 9.0 | 5.0 | 1.7 |
| Total Drilling Activity | 101.0 | 67.8 | 61.0 | 41.5 |

(1) As of March 31, 2008, a total of 161 productive wells, 84 drilled in 2008 and 77 drilled in 2007, were waiting to be fractured and/or for gas pipeline connection.

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

| | Three Months Ended March 31, | | | |
|---|---|---|---|---|
| | 2008 | | 2007 | |
| | Gross | Net | Gross | Net |
| Rocky Mountain Region: | | | | |
| Wattenberg | 45.0 | 21.7 | 30.0 | 13.8 |
| Piceance | 21.0 | 13.4 | 16.0 | 14.1 |
| NECO | 29.0 | 26.6 | 13.0 | 13.0 |
| North Dakota | | | 2.0 | 0.6 |
| Total Rocky Mountain Region | 95.0 | 61.8 | 61.0 | 41.5 |
| Appalachian Basin | 4.0 | 4.0 | | |
| New York | 1.0 | 1.0 | | |
| Fort Worth Basin | 1.0 | 1.0 | | |
| Total | 101.0 | 67.8 | 61.0 | 41.5 |

**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.

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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 sheets. 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. As of March 31, 2008, we have drilled for the partnership a total of 100 wells, with completion and equipping operations to continue through the third quarter of 2008. The balance of the partnership s prepayment remaining at March 31, 2008, was $39.9 million. 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.

**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 were made in the open market or in private transactions, at times and in amounts that we deemed appropriate. Shares were 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). For the three months ended March 31, 2008, an additional 64,110 common shares were purchased at a cost of $4.4 million ($67.95 average price paid per share), including 13,756 shares from our executive officers at a cost of $0.9 million ($68.19 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 and options that were exercised in 2007 and 2008. All shares were subsequently retired. As the share purchase program expired on April 30, 2008, the remaining 1,400,979 shares authorized for purchase at March 31, 2008, have effectively expired.

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.

**Contractual Obligations and Contingent Commitments**

The table below sets forth our contractual obligations and contingent commitments as of March 31, 2008:

| | | Payments due by period | | | |
|---|---|---|---|---|---|
| **Contractual Obligations and Contingent Commitments[1]** | **Total** | **Less than 1 year** | **1-3 years** | **3-5 years** | **More than 5 years** |
| | | | *(in thousands)* | | |
| Long-Term Debt[2] | $ 203,000 | $ | $ | $ | $ 203,000 |
| Interest on long-term debt[2] | 240,797 | 24,360 | 48,720 | 48,720 | 118,997 |
| Operating leases | 4,921 | 2,194 | 1,993 | 682 | 52 |
| Asset retirement obligations | 21,213 | 50 | 100 | 100 | 20,963 |
| Rig commitments[3] | 22,925 | 10,605 | 12,320 | | |
| Drilling commitments[4] | 3,217 | | 717 | | 2,500 |
| Derivative agreements[5] | 76,895 | 57,518 | 19,351 | 26 | |
| Other liabilities[6] | 8,383 | 245 | 720 | 720 | 6,698 |
| Total | $ 581,351 | $ 94,972 | $ 83,921 | $ 50,248 | $ 352,210 |

(1) Table does not include maximum annual repurchase obligation of $7 million as of March 31, 2008, see Note 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements.

(2) Amounts presented consist only of amounts due related to our 12% senior notes and does not include any amounts due under our credit facility as it was undrawn as of March 31, 2008. Interest on long-term debt, therefore, represents only amounts payable to holders of our

12% senior notes due 2018.

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(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 7, Commitments and Contingencies, to our accompanying condensed consolidated financial statements. These amounts do not include advances for future drilling contracts totaling $40.9 million at March 31, 2008.

(5) Amount represents gross liability related to fair value of derivatives and related costs. Includes fair value of derivatives for natural gas marketing activities, Petroleum Development Corporation s share of oil and natural gas production and derivatives contracts we entered into on behalf of our affiliate partnerships as the managing general partner. We have a related net receivable from the partnerships of $18.4 million as of March 31, 2008.

(6) Includes funds held from revenue distribution to third party investors for plugging liabilities related to wells we operate and deferred officer compensation.

**Commitments and Contingencies**

As managing general partner of 33 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. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

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.

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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.

*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. 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

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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. 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.

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.

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

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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.

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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.

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.

**Quantitative and Qualitative Disclosure About Market Risk**

**Market-Sensitive Instruments and Risk Management**

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

***Interest Rate Risk***

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. Our interest-bearing cash and cash equivalents includes our money market accounts, short-term certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of March 31, 2008, is $53.3 million with an average interest rate of 1.99%.

In February 2008, we completed the issuance and sale of $203 million aggregate principal amount of 12% senior notes due 2018, which we utilized to pay down our variable rate credit facility. The fixed-price debt transaction reduced our current sensitivity to interest rate fluctuations as we did not have any borrowings outstanding under our credit facility at March 31, 2008.

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***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.

*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 March 31, 2008, 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, CIG-based contracts for other Colorado production and NYMEX-based swaps and collars for our Colorado oil production.

For swap instruments, we receive a fixed price for the derivative contract 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 fixed call strike price, we receive the market price from the purchaser and pay the difference between the call strike price and market price to the counterparty. If the market price falls below the fixed put strike price, we receive the market price from the purchaser and receive the difference between the put strike price and market price from the counterparty. If the market price is between the call and the put strike price, no payments are due from either party.

With regard to our natural gas marketing activities, we enter 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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The following table presents monthly average NYMEX and CIG closing prices for oil and natural gas for the three months ended March 31, 2008, and the year ended December 31, 2007, as well as average sales prices we realized for the respective commodity.

| | Three Months Ended March 31, 2008 | Year Ended December 31, 2007 |
|---|---|---|
| Average Index Closing Prices | | |
| Oil (per Barrel) | | |
| NYMEX | $ 93.69 | $ 69.79 |
| Natural Gas (per MMbtu) | | |
| NYMEX | 8.03 | 6.89 |
| CIG | 6.96 | 3.97 |
| Average Sales Price | | |
| Oil | 81.14 | 60.65 |
| Natural Gas | 7.33 | 5.33 |

Based on a sensitivity analysis as of March 31, 2008, 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 $46.3 million and a 10% decrease in oil and natural gas prices would have resulted in a decrease in unrealized losses of $49.8 million.

See Note 4, *Derivative Financial Instruments*, to our accompanying condensed consolidated financial statements included in this report for additional disclosure regarding derivative instruments including, but not limited to, a summary of our open derivative positions as of March 31, 2008.

***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 or the three months ended March 31, 2008.

***Disclosure of Limitations***

Because the information above included only those exposures that exist at March 31, 2008, 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.

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## BUSINESS

### Our Company

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 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.

### 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.

*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

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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 we bore the risk of changes in costs. In addition, we have typically purchased a 20% to 37% working interest in the wells developed through these partnerships. In September 2006, we raised approximately $90 million through investor subscriptions in one drilling partnership, and in August 2007, we raised approximately $90 million through an additional drilling partnership. Our 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 and 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

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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.

*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 area, 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. 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.

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*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*

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. 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 |

**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.

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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.

*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.

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.

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**Natural Gas Industry Overview**

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

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

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

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

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

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

**Operations**

***Exploration and Development Activities***

Our 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

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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.

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

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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.

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**Production, Sales, Prices and Lifting Costs**

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

| | Year Ended December 31, | | |
|---|---|---|---|
| | 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 |

(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.

**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

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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%.

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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 |

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**Title to Properties**

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the oil and natural gas industry. As is customary in the industry, a 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.

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.

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**Natural Gas Marketing**

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

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

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

RNG, our wholly owned subsidiary, is a natural gas marketing company that specializes in the purchase, aggregation and sale of natural gas production in our Eastern operating areas. RNG markets the natural gas we produce and also purchases natural gas 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.

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**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.

**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

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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.

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

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been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, RCRA and analogous state laws, as well as state laws governing the management of oil and natural gas wastes. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the disposal site or sites where the release occurred and companies that disposed of or arranged for the disposal of the hazardous substances found at the site. Persons who are or were responsible for release of hazardous substances under CERCLA may be subject to full liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. As an owner and operator of oil and natural gas wells, we may be liable pursuant to CERCLA and similar state laws.

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

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**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.

**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.

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**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.

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## MANAGEMENT

### Board of Directors and Executive Officers

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

| Name | Age | Position(s) | Director Since | Directorship Term Expires |
|---|---|---|---|---|
| Steven R. Williams | 57 | Chairman, Chief Executive Officer and Director | 1983 | 2009 |
| Richard W. McCullough | 56 | Vice Chairman, President, Chief Financial Officer and Director | 2007 | 2008 |
| Darwin L. Stump | 53 | Chief Accounting Officer | | |
| Eric R. Stearns | 50 | Executive Vice President | | |
| Daniel W. Amidon | 47 | General Counsel and Secretary | | |
| Barton R. Brookman, Jr. | 45 | Senior Vice President Exploration and Production | | |
| Vincent F. D Annunzio | 55 | Director | 1989 | 2010 |
| Jeffrey C. Swoveland | 53 | Director | 1991 | 2008 |
| Kimberly Luff Wakim | 50 | Director | 2003 | 2009 |
| David C. Parke | 41 | Director | 2003 | 2008 |
| Anthony J. Crisafio | 55 | Director | 2006 | 2009 |
| Joseph E. Casabona | 64 | Director | 2007 | 2008 |
| Larry F. Mazza | 47 | Director | 2007 | 2008 |

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

*Richard W. McCullough* was appointed President in March 2008, was elected Vice Chairman of our Board of Directors in December 2007, was appointed Chief Financial Officer in November 2006 and also served as our Treasurer from November 2006 until October 2007. Prior to joining our company, Mr. McCullough served as an energy consultant from July 2005 to November 2006. From January 2004 to July 2005, Mr. McCullough served as president and chief executive officer of Gasource, LLC, Dallas, Texas, a marketer of long-term, natural gas supplies. From 2001 to 2003, Mr. McCullough served as an investment banker with J.P. Morgan Securities, Atlanta, Georgia, and served in the public finance utility group supporting bankers nationally in all natural gas matters. Additionally, Mr. McCullough has held senior positions with Progress Energy, Deloitte and Touche, and the Municipal Gas Authority of Georgia. Mr. McCullough, a Certified Public Accountant, was a practicing certified public accountant for 8 years.

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

*Eric R. Stearns* was appointed Executive Vice President in March 2008. Prior to his current position, Mr. Stearns served as Executive Vice President Exploration and Production since December 2004, Executive Vice President Exploration and Development from November 2003 until December 2004, and Vice President Exploration and Development from April 1995 until November 2003. Mr. Stearns joined our company as a geologist in 1985 after working at Hywell, Incorporated and for Petroleum Consultants.

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

*Barton R. Brookman, Jr.* was appointed Senior Vice President Exploration and Production in March 2008. Previously Mr. Brookman served as Vice President Exploration and Production since joining us in July 2005. Prior to joining our company, Mr. Brookman worked for Patina Oil and Gas and its predecessor Snyder Oil for 17 years in a series of positions of increasing responsibility ending his service as Vice President of Operations of Patina.

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

*Jeffrey C. Swoveland* is the Chief Operating Officer of Coventina Healthcare Enterprises, a medical device company specializing in therapeutic warming and multi-modal treatment systems used in the treatment, rehabilitation and management of pain since May 2007. Previously, Mr. Swoveland served as the Chief Financial Officer of Body Media, Inc., a life-science company specializing in the design and development of wearable body monitoring products and services, from September 2000 to May 2007. Prior thereto, Mr. Swoveland held various positions, including Vice President of Finance, Treasurer and interim Chief Financial Officer, with Equitable Resources, Inc., a diversified natural gas company, from 1997 to September 2000. Mr. Swoveland serves as a member of the Board of Directors of Linn Energy, LLC, a public, independent natural gas and oil company.

*Kimberly Luff Wakim*, an Attorney and Certified Public Accountant, is a Partner with the Pittsburgh, Pennsylvania law firm Thorp, Reed & Armstrong LLP, where she serves as a member of the Executive Committee. Ms. Wakim joined Thorp Reed & Armstrong LLP in 1990.

*David C. Parke* is a Managing Director in the investment banking group of Boenning & Scattergood, Inc., West Conshohocken, Pennsylvania, a full-service investment banking firm. Prior to joining Boenning & Scattergood in November 2006, he was a Director with Mufson Howe Hunter & Company LLC, Philadelphia, Pennsylvania, an investment banking firm, from October 2003 to November 2006. From 1992 through 2003, Mr. Parke was Director of Corporate Finance of Investec, Inc., and its predecessor Pennsylvania Merchant Group Ltd., investment banking companies. Prior to joining Pennsylvania Merchant Group, Mr. Parke served in the corporate finance departments of Wheat First Butcher & Singer, now part of Wachovia Securities, and Legg Mason, Inc., now part of Stifel Nicolaus.

*Anthony J. Crisafio*, a Certified Public Accountant, serves as an independent business consultant, providing financial and operational advice to businesses and has done so since 1995. Additionally, Mr. Crisafio has served as the Chief Operating Officer of Cinema World, Inc. from 1989 until 1993 and was a partner with Ernst & Young from 1986 until 1989.

*Joseph E. Casabona* served as Executive Vice President and member of the Board of Directors of Denver based Energy Corporation of America, a natural gas exploration and development company, from 1985 to his retirement in May 2007. Mr. Casabona s responsibilities included strategic planning as well as executive oversight of the drilling operations in the continental United States and internationally.

*Larry F. Mazza* has served as Chief Executive Officer of MVB Bank Harrison, Inc., in Bridgeport, West Virginia since March 2005. Prior to the formation of MVB Bank Harrison, Mr. Mazza served as Senior Vice

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President Retail Banking Manager for BB&T in West Virginia, where he was employed from June 1986 to March 2005.

**Corporate Governance**

*Corporate Governance Guidelines*

In January 2005, we adopted Corporate Governance Guidelines to promote the effective functioning of our Board of Directors and related committees. The Corporate Governance Guidelines govern the structure and functioning of the Board and establish the Board s policies on a number of corporate governance issues. The guidelines are posted under Governance Policies in the corporate governance section of our internet site at www.petd.com.

*Board of Directors*

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

*Director Independence*

Subject to some exceptions and transition provisions, the NASDAQ listing standards generally provide that a director will not be independent if:

- the director is, or at any time during the past three years was, employed by us;
- the director or a member of the director s immediate family has received from us compensation of more than $100,000 during any period of 12 consecutive months within the three years preceding the determination of independence other than for service as a director; or compensation paid to a family member who is an employee of our company (other than an executive officer);
- the director is a family member of an individual who is, or at any time during the past three years was, an executive officer of our company;
- the director or a member of the director s immediate family is a partner in, or a controlling person of, or an executive officer of any organization to which we made, or from which we received, payments for property or services in the current or any of the three past fiscal years that exceed 5% of the recipient s consolidated gross revenues for that year, or $200,000, whichever is more;
- the director or a member of the director s immediate family is employed as an executive officer of another entity where at any time during the past three years any of our executive officers serves on the compensation committee of the other entity; or
- the director or a member of the director s immediate family is a current partner of PricewaterhouseCoopers LLP, our independent registered public accounting firm, or during the past three years was a partner or employee of either PricewaterhouseCoopers LLP or KPMG LLP, our former independent registered public accounting firm.

Audit committee members are subject to additional, more stringent NASDAQ and Exchange Act requirements.

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The Board has reviewed business and charitable relationships between our company and each non-employee director to determine compliance with the NASDAQ listing standards described above and to evaluate whether there are any other facts or circumstances that might impair a director s independence. The Board has determined that all non-employee directors are independent under NASDAQ Marketplace Rule 4200 and the Exchange Act.

*Board Meetings and Attendance*

The Board met 15 times in 2007. Each of our directors attended at least 75% of the aggregate Board and committee meetings (on which he or she served) during 2007.

*Annual Meeting Attendance*

As specified in our Corporate Governance Guidelines, directors are strongly encouraged to attend the annual meeting of shareholders. All directors attended last year s meeting.

*Committees of the Board*

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

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

The non-employee directors generally meet in executive sessions without the presence of employee directors at their discretion in connection with each regularly scheduled board meeting. Mr. Swoveland serves as Presiding Independent Director at these sessions; however, the other non-employee directors may, in the event of his absence, select another director to preside over a particular session.

*Audit Committee.* The audit committee, which met nine times in 2007, is comprised entirely of persons whom the Board has determined to be independent under NASDAQ Marketplace Rule 4200(a)(15), Section 301 of the Sarbanes-Oxley Act of 2002 and Section 10A(m)(3) of the Exchange Act. Mr. Swoveland chairs the committee; other audit committee members are Ms. Wakim, Mr. Parke, Mr. Crisafio and Mr. Casabona. The Board has determined that Mr. Swoveland, Ms. Wakim, Mr. Crisafio and Mr. Casabona qualify as audit committee financial experts as defined by SEC regulations and that all the audit committee members are independent of management. The audit committee s purpose is to assist the Board in monitoring the integrity of our financial reporting process, systems of internal controls and financial statements and our compliance with legal and regulatory requirements. Additionally, the committee is directly responsible for the appointment, compensation and oversight of our independent auditors for the purpose of preparing or issuing an audit report or related work and to assess the need for an internal audit function and recommend its establishment when deemed appropriate.

In performing its responsibilities, the audit committee monitors the integrity of our financial reporting process and systems of internal controls regarding finance, accounting and legal compliance; monitors the independence of the Independent Registered Public Accounting Firm; and provides an avenue of communications among the Independent Registered Public Accounting Firm, management and the Board of Directors. The Board has adopted a charter of the audit committee which is posted on our website. The Board continues to assess the adequacy of the charter and will revise it as necessary.

*Compensation Committee.* The Board has determined that all members of the compensation committee are independent under Rule 4200(a)(15) of the NASDAQ s listing standards. The compensation committee met 10 times in 2007. The Board has adopted a compensation committee charter which is posted on our website.

The purpose and functions of the compensation committee are to (1) oversee the development of our compensation strategy, (2) oversee the administration of our compensation programs, (3) evaluate the performance of and set compensation for our Chief Executive Officer, (4) review and approve the elements of compensation for our other executive officers, (5) negotiate the terms of employment agreements with our executive officers, (6) review and recommend to the full Board compensation for our directors and changes in compensation levels to the Board, (7) approve equity grants and recommend equity-based incentive plans necessary to implement our compensation strategy, and (8) administer all of our equity-based incentive programs.

*Compensation Committee Interlocks and Insider Participation.* There are no compensation committee interlocks.

*Executive Committee.* The purpose and functions of the executive committee are to exercise the powers and duties of the Board between Board meetings and, while the Board is not in session, implement the policy decisions of the Board. The Board has adopted an executive committee charter which is posted on our website.

*Nominating and Governance Committee.* The Board has determined that all members of the nominating and governance committee are independent under Rule 4200(a)(15) of the NASDAQ s listing standards. The nominating and governance committee met five times in 2007. The purpose and functions performed by the committee are to (1) assist the Board by identifying individuals qualified to become Board members and to recommend to the Board the director nominees for the next annual meeting of shareholders or fill any vacancies; (2) recommend to the Board corporate governance guidelines applicable to our company; (3) lead the Board in its annual review of the Board s performance and (4) recommend to the Board director nominees for each committee. The Board has adopted a charter for the nominating and governance committee. The charter has been posted on our website.

*Director Qualifications and Selection.* The Board has adopted director nomination procedures that prescribe the process the nominating and governance committee will use to select our nominees for election to the Board. The nominating and governance committee evaluates each candidate based on the candidate s level and diversity of experience and knowledge (specifically within the industry and relevant industries in which we operate, as well as his or her general overall experience and knowledge), skills, education, reputation and integrity, professional stature and other factors that may be relevant depending on the particular candidate. Additional factors considered by the committee include the size and composition of the Board at a particular time, and allowing us to benefit from having a broad mixture of skills, experience and perspectives on the Board. Accordingly, one or more of these factors may be given more weight in a particular case at a particular time, no single factor would be viewed as determinative, and the committee has not specified any minimum qualifications that the committee believes must be met by any particular nominee. Our director nomination procedures are posted on our website.

The committee identifies director candidates primarily through recommendations made by the non-employee directors. These recommendations are developed based on the directors own knowledge and experience in a variety of fields, and research conducted by our staff at the committee s direction. The committee also considers recommendations made by the employee directors, employees, shareholders, and

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others, including search firms. All recommendations, regardless of the source, are evaluated on the same basis against the criteria contained in the guidelines. The committee has the authority to engage consultants to help identify or evaluate potential director nominees but has not done so recently.

*Shareholder Recommendations.* Our nominating and governance committee will consider director candidates recommended by our shareholders. Any shareholder who wishes to recommend a prospective Board nominee to the committee should notify the nominating and governance committee of their recommendation by writing to the committee at our headquarters, or by sending the information via email to board@petd.com. All recommendations will be received by the nominating and governance committee.

A submission recommending a candidate should include:

- sufficient biographical information to allow the committee to evaluate the candidate in light of the guidelines;
- an indication as to whether the proposed candidate will meet the requirements for independence under the NASDAQ guidelines;
- information concerning any relationships between the candidate and the shareholder recommending the candidate; and
- material indicating the willingness of the candidate to serve if nominated and elected.

*Shareholder Nominations.* Shareholders who wish to may nominate candidates for election to the Board. Our By-Laws require shareholders who wish to submit nominations of persons for election to the Board of Directors at the annual meeting of shareholders to follow certain procedures. The shareholder must give written notice to the Corporate Secretary at Petroleum Development Corporation, 120 Genesis Boulevard, Bridgeport, West Virginia 26330 or may email notice to board@petd.com, not later than 80 days prior to the first anniversary of the preceding year s annual meeting or within 10 days of our public announcement of the date of our annual shareholder meeting. The shareholder notice also must be received by us no earlier than 90 days prior to the annual meeting. The shareholder must be a shareholder of record at the time the notice is given. The written notice must set forth (a) as to each nominee all information relating to that person that is required to be disclosed in solicitations of proxies for election of directors in an election contest, or is otherwise required, in each case pursuant to Regulation 14A under the Exchange Act (including such person s written consent to being named in the proxy statement as a nominee and to serving as a director if elected); (b) as to the shareholder giving the notice and the beneficial owner, if any, on whose behalf the nomination is made (1) the name and address of the shareholder, as they appear on our books, and of such beneficial owner and (2) the class and number of shares of our securities that are beneficially owned by such shareholder and the beneficial owner; and (c) any material interest of such shareholder and such beneficial owner in such nomination.

*Planning and Finance Committee.* The purpose of the planning and finance committee is to oversee the responsibilities of the Board relating to planning and finance, including: (1) to organize and oversee the Board s participation in the development of our strategic plan and the risk assessment and management process; (2) to follow the progress in the implementation of our strategic plan and to advise the Board if additional Board action appears to be needed to assure successful implementation of the plan or if a need exists to revise the plan in the face of changing conditions or other factors; (3) to assure that management is addressing the personnel requirements for the successful implementation of our strategic plan; (4) to assure that a talent-rich organization is being developed to address both current and future leadership needs; (5) to assure that robust management development and succession planning processes are developed and implemented for management at all levels in our company; and (6) work with the Chief Financial Officer and other executive management regarding corporate financial matters including operating and capital budgets, capital structure, dividends, and other significant financial and capital issues. The Board has adopted a charter for the planning and finance committee which is posted on our website.

*CEO Succession*

During 2007 the current Chief Executive Officer communicated to the Board his intention to retire during 2008. The Board designated a committee comprised of five independent Board members serving at the time (Swoveland (Chair), Wakim, D Annunzio, Parke and Crisafio) to serve as a search committee for a new Chief Executive Officer and to recommend a successor to the Board. The search committee developed a process, identified and evaluated candidates, and recommended to the Board that Richard W. McCullough, our Chief Financial Officer be the next Chief Executive Officer. In December 2007, the full Board approved the recommendation.

*Communications with Directors*

Shareholders wishing to communicate with the Board or a committee may do so by writing to the attention of the Board or committee at the corporate headquarters or by emailing the Board at board@petd.com, with Board or appropriate committee in the subject line.

*Code of Business Conduct and Ethics*

In January 2003, we adopted our Code of Business Conduct and Ethics, as amended, applicable to all of our directors, officers, employees, agents, representatives and consultants. Our principal executive officer, principal financial officer and principal accounting officer are subject to additional specific provisions under the code of conduct. Our code of conduct is posted on our website at www.petd.com. In the event of an amendment to, or a waiver of, including an implicit waiver, the code of conduct, we will disclose the information on its internet website. On November 17, 2007, the Board approved a waiver of regarding any potential conflict related to the service of Mr. Swoveland on the Board of Directors of Linn Energy LLC. If the Board of Directors becomes aware of a potential conflict in the future, the Board of Directors will consider at that time whether or not to continue this waiver.

**Director Compensation**

For the 2007-2008 Board term, each non-employee director was paid an annual fee of $55,000 and received 2,000 shares of restricted stock, which was awarded on the date of the 2007 annual meeting. The Presiding Independent Director was paid an additional fee of $27,500. Each non-employee director received for services on each committee on which he or she served the following fees:

| Committees of the Board | Chair | Non-Chair Member |
|---|---|---|
| Audit | $ 22,500 | $ 10,000 |
| Compensation | 7,500 | 2,500 |
| Executive | | 5,000 |
| Nominating and Governance | 7,500 | 2,500 |
| Planning and Finance | 7,500 | 2,500 |

Pursuant to the shareholder-approved 2005 Non-Employee Director Restricted Stock Plan, as of the date of each annual shareholders meeting, each non-employee director will be awarded a specified number of shares of restricted stock as determined by the Board. Directors receiving restricted stock under the Restricted Stock Plan will have all of the rights of a shareholder including the right to vote the shares and receive cash dividends and other cash distributions. Restricted stock will be subject to the restrictions for the restricted period commencing on the date the stock is awarded.

Each non-employee director may also choose to defer a portion or all of his or her annual cash compensation by participating in the Non-Employee Director Deferred Compensation Plan. The plan s trustee invests all cash deposits received exclusively in our common stock.

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On March 8, 2008, the Board approved compensation for the 2008-2009 Board year. Such compensation is principally the same to the prior Board year with the exceptions that (1) the annual retainers for the compensation committee chairman and members were increased to $10,000 and $5,000 from $7,500 and $2,500, respectively, and (2) subject to shareholder approval, the vesting of prior and future restricted stock awards would be changed subject to approval by our stockholders.

**2007 Director Compensation Table**

| Name(1) | Fees Earned or Paid in Cash | Stock Awards(2) | Total |
|---|---|---|---|
| Kimberly Luff Wakim | $ 59,000 | $ 72,280 | $ 131,280 |
| Vincent F. D Annunzio | 56,250(3) | 72,280 | 128,530 |
| David C. Parke | 67,125 | 72,280 | 139,405 |
| Jeffrey C. Swoveland | 94,781 | 72,280 | 167,061 |
| Anthony J. Crisafio | 57,750 | 72,280 | 130,030 |
| Joseph E. Casabona | 11,542 | 64,037(4) | 75,579 |
| Larry F. Mazza | 10,625 | 64,037(4) | 74,662 |

(1) Compensation paid to Messrs. Williams and McCullough for their services as executive officers is shown in the Summary Compensation Table; neither receives additional compensation for services as a Director.
(2) For all Directors, excluding Messrs. Casabona and Mazza, the amounts represent the grant date fair value of the 2007-2008 term restricted stock award. The grant date fair value was computed in accordance with FAS 123(R) by multiplying the number of shares awarded (2,000 shares) by the closing price of our common stock on the date of grant ($36.14 on August 28, 2007).
(3) Includes amounts deferred (100%) pursuant to stock purchase election under the Non-Employee Deferred Compensation Plan.
(4) Messrs. Casabona and Mazza were appointed to serve on the Board effective October 26, 2007. The amount represents the grant date fair value of a pro rata portion of the 2007-2008 term restricted stock award. The grant date fair value was computed in accordance with FAS 123(R) by multiplying the number of shares awarded (1,355 shares) by the closing price of our common stock on the date of grant ($47.26 on November 12, 2007).

**Compensation Discussion And Analysis**

The Board has assigned to the compensation committee responsibility for developing and overseeing our compensation programs and executive compensation. The committee consists entirely of independent Board members. The committee has been authorized by the Board to make final determinations for all elements of compensation for the executive officers. Independent board members who are not part of the committee are often consulted as part of the committee s decision process. The committee also negotiates terms and approves all executive employment agreements and administers our long-term incentive plans.

***Summary***

The committee s overall goal is to design an executive compensation plan with the following characteristics:

Is fair to both the executive and our company

Is competitive with compensation being paid by other oil and gas companies of similar size and complexity

Is competitive with companies located in the same geographic regions as our operations

Helps retain key executives

Avoids encouraging illegal or unethical activities

Rewards efforts that improve our performance

Is appropriate considering compensation of our other employees

The committee, working with nationally recognized compensation consultant Towers Perrin, has developed and annually reviews and updates a peer group of companies to use to establish total level of compensation and components of compensation at competitive companies. Executive compensation includes salary, short-term incentive (cash bonus) and long-term incentive (stock or stock-based) compensation. In addition executives participate in and benefit from the qualified benefit programs available to all employees as well as to an executive retirement plan and other perquisites.

The peer group median compensation levels are the primary basis for salary, short-term and long-term incentive target levels. Position, contributions to company performance, future potential, skills and other factors are also considered. The committee seeks to tie a large percentage of the short-term incentive to specific performance goals established at the beginning of the year. In 2007, the committee set a target for production growth and intended to set a target for earnings per share but did not do so due to the delay in the filing of the financial statements for 2006 and significant operational changes at our company due primarily to several large acquisitions which we completed at the beginning of 2007. As a result 60% of the short-term incentive in 2007 was determined by the committee following the end of the year, although our financial performance was compared to estimates made by us during the year was considered. In making its decision about the discretionary portion of the awards positive factors the committee considered included the significant increase in the value of our stock, progress made in the accounting area, the installation and start-up of a new enterprise software system, and the very competitive level of our finding and development costs. Areas of concern included the high levels of G&A and operating costs and the material weaknesses in the internal control over financial reporting.

For long-term incentives the committee first sets dollar targets based on the peer group levels and factors related to the individual executive, and then determines the number of shares using valuation methods based on the average price for the preceding December (the December 2006 average closing price for 2007 awards and the December 2007 average closing price for 2008 awards) and adjusted for the type of award and the timing and likelihood of vesting. The compensation consultant assists us in evaluating the value of awards based on generally accepted valuation methods consistent with the compensation reported for SEC reporting.

The compensation committee also consults with our Chief Executive Officer regarding proposed peer group changes and for his evaluation of performance and suggestions for compensation of the other executive officers. Topics discussed with our Chief Executive Officer include individual executive achievement of key operating targets, participation in and support for development and execution of our strategic plan, management development and succession planning, the Chief Executive Officer s assessment of the executives contributions to our success, and the limitations or shortcomings in the executives performance or potential.

In 2006, using a similar method to establish compensation levels, the compensation of each of our five named executives ranged from the 38$^{th}$ percentile to 60$^{th}$ percentile of the comparable peer group executive (41$^{st}$ percentile for our Chief Executive Officer). While final numbers for peer group compensation for 2007 are not available, the committee anticipates that our compensation for executives in 2007 will be modestly higher than the median of the peer group in total. These final compensation levels in excess of the median of the peer group were justified by the impressive performance of our company in 2007, with production increase of 65%, reserve increase of 112% and a significant increase in our stock price, which performance was remarkable by general market and by industry standards.

The committee also recommended and the Board approved changes to Board compensation for 2007 and 2008. As with the executive compensation, the peer group compensation was a primary factor used to determine competitive levels of cash and equity compensation for Board members.

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***Compensation Design***

*Compensation Philosophy and Objectives*

The committee s philosophy is to provide compensation packages that will attract, motivate and retain executive talent and deliver rewards for superior performance and consequences for underperformance. The committee considers many factors in establishing the compensation packages for our executive officers. The ultimate goal is to provide compensation that is fair to both our company and the executive officers, that motivates behavior that will enhance the value of our company, that avoids encouraging behavior that does not serve our best interests and that will allow us to attract and retain executive officers.

The committee believes the following characteristics of a compensation program contribute to the implementation of its philosophy:

- Offer a total compensation program that is competitive with the compensation practices of those peer companies with which we compete for talent;

- Tie a significant portion of executive compensation to our achievement of pre-established financial and operating objectives and to personal objectives established for each executive individually;

- Provide a significant portion of overall compensation in the form of equity-based compensation in order to align the interests of our executives with those of our shareholders and to avoid excess focus on short-term results; and

- Structure a significant proportion of total compensation in a fashion that promotes executive retention.

*Pay-for-Performance*

The committee believes that a significant portion of executive compensation should be closely linked to both our and the individual s performance. The committee s pay-for-performance philosophy is reflected in our compensation practices, which tie a significant portion of executive compensation to the achievement of our financial and operating objectives and also to take into account personal objectives and performance. This philosophy is reflected in annual incentive awards, which are directly linked to the achievement of short-term financial and operating objectives set by the committee and have potential payouts ranging from zero to as much as 180% of the target for each of the components. During 2007, the targets were increases in production, and the committee s assessment of other factors related to the individual s performance and development. Factors deemed particularly important in the committee s assessment of the discretionary portion of the short-term incentive, or STI, compensation for 2007 included dramatic increases in reserves and production and our overall growth, management s efforts relating to the impending retirement of our Chief Executive Officer and management s efforts in improving our historical financial and accounting systems and reporting. The following table summarizes the criteria used in determining the 2007 bonus amount. Earnings per share, which the committee had planned to include as a factor, was ultimately not used in determining any formula-based short-term incentive in 2007 due to the delay in filing the 2006 Form 10-K and major operational changes at our company due to several large acquisitions in early 2007. As a result, the committee included financial performance as one of the criteria in its discretionary evaluation for 2007, which was increased from 30% to 60% of the overall bonus calculation. This discretionary portion of the STI program permits the committee to account for individual performance and differentiate among executives. In addition, half of the discretionary annual bonus was based on 2007 earnings performance compared to internal estimates made by management during the year. The committee also assesses individual executive performance with input from the Chief Executive Officer as well as other Board members and other committees. When determining what portion of the discretionary income to award, the committee discusses each executive individually and considers all the available information. In 2008, the committee established performance targets for 70% of the STI, with the balance determined at the discretion of the committee. In 2007 and 2008, 100% of Mr. Stump s STI is determined by the committee at its discretion.

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**Pay-for Performance Table**

| Criteria | Lower Threshold Amount | Target Bonus | Maximum Bonus | Percent of Total Maximum Bonus |
|---|---|---|---|---|
| 2007: | | | | |
| Production (Mmcfe) | 24,000 | 26,000 | 28,000 | 40% |
| Discretionary evaluation | Compensation Committee Determination | | | 60% |
| 2008: | | | | |
| Production (Mmcfe) | 35,000 | 37,000 | 39,000 | 40% |
| Diluted earnings per share | $ 2.55 | $ 3.05 | $ 3.55 | 30% |
| Discretionary evaluation | Compensation Committee Determination | | | 30% |

The committee also ties compensation to performance through equity-based long term incentive, or LTI, awards that are designed to motivate executives to meet our long-term performance goals and to tie their interests to those of the shareholders. In 2007 and for 2008, the LTI awards are restricted stock which vest over time, and long-term incentive performance, or LTIP, shares. The LTIP shares will vest only if certain minimum thresholds of stock price appreciation are met. One-half of the LTIP shares will vest and be issued based upon an annual stock price increase of approximately 12%, with the starting price based on the average price of the stock in December proceeding the award year. An additional 25% of the awarded LTIP shares will vest and be issued at annualized hurdle rate of 16% and an additional 25% at 20%. The stock price used to determine if the LTIP shares will vest will be the average daily closing price for each of the three monthly periods: December 2009, 2010 and 2011 for the 2007 awards, and 2010, 2011, and 2012 for the 2008 awards. Any shares not vested in 2009 or 2010 (or 2010 and 2011 for the 2008 awards) will remain eligible to be vested in future years; however, any unvested shares at December 31, 2011 for the 2007 awards or December 31, 2012 for the 2008 awards will be forfeited. The committee decided to use three measurement dates to take into account the volatility of energy prices and their impact on our stock price.

As a result of the structure of the STI and LTI compensation, a significant amount of variable compensation under our compensation program is contingent on the achievement of our key financial and operating objectives and on increasing the value of the shares of our stock.

*The Role of Equity-Based Compensation*

Our LTI program is an integral part of our overall executive compensation program. The LTI program is intended to serve a number of objectives including aligning the interests of executives with those of our shareholders and focusing senior executives on the achievement of well-defined, long-term performance objectives that are aligned with our corporate strategy, thereby establishing a direct relationship between compensation and shareholder value. The program also furthers the goal of executive retention, since the executive officer will forfeit any unvested awards in the event the officer voluntarily terminates employment with us without good reason.

Historically, the primary form of equity compensation awarded by us was qualified and non-qualified stock options, although such grants were not issued on a regular basis. This form was selected because of the favorable individual and corporate accounting and tax treatments provided by rules at the time, and the widespread use of stock options in executive compensation. In 2004, the committee began utilizing a combination of restricted stock and options for executive compensation, believing that the restricted stock was better appreciated by employees and resulted in less dilution for the shareholders. Beginning in 2006, the accounting treatment for stock options changed as a result of the applicability of Statement of Financial Accounting Standards No. 123(R), making the use of stock options less attractive. As a result, the committee assessed the desirability of granting only shares of restricted stock to executives, and concluded that shifting entirely to restricted stock would provide an equally motivating form of incentive compensation, while permitting the issuance of fewer shares,

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thereby reducing potential dilution to other shareholders. The committee did want to tie the value received by executives to performance for a portion of the equity compensation, thereby providing executives with a greater incentive to focus on the long-term appreciation of the stock. To accomplish this, a portion of the LTI for each executive consists of LTIP shares, which require both the passage of time and specified increases in the stock price to vest.

In making long-term incentive awards, the committee uses a pre-determined market-based value approach. The committee determines the dollar value of awards in the marketplace using a valuation methodology. The committee establishes the desired dollar value for each executive officer relative to the market. The corresponding number of equity instruments to be awarded is then determined using the same valuation methodology, based on prevailing factors in advance of the award date. The valuation for financial statement purposes is subsequently re-calculated based on the prevailing factors at the time of the award.

The value-based approach can cause the number of equity instruments needed to be granted from year to year to vary, even though the awards may have the same dollar value. This can be caused by, among other things, fluctuations in our common stock price at the time of grant. This issue is further addressed in the Long-Term Incentives section.

Mr. Williams has announced his planned retirement in 2008, Mr. McCullough was named as Mr. Williams successor, and Mr. Riley resigned in early 2008. As a result a large part of the executive team will have new and expanded responsibilities in 2008. Largely as a result of relatively short tenure with our company the new executive team does not have a significant ownership position in our stock. As a result of these factors, and the additional and unusual demands of a major management transition, the committee felt that a one time award of stock, vesting over a 5-year time frame, would both compensate the management team for their additional efforts and provide a better link between their interests and those of the shareholders. 32,711 shares of restricted common stock were issued to Messrs. McCullough, Stearns, Brookman and Amidon in connection with this issuance.

*Use of Consultants and Benchmarking to Help Establish Target Compensation Levels*

The compensation committee utilizes the compensation consulting services of Towers Perrin. Over the past 18 months, Towers Perrin: assisted the committee with a review and revision of the peer group, conducted a competitive benchmarking of our executive and non-employee director compensation programs, helped the committee in its redesign of the LTI program in 2007 as described below, and led an educational session focused on new SEC pay disclosure rules. The committee periodically assesses the effectiveness and competitiveness of our executive compensation structure with the assistance of Towers Perrin, and utilizes the assistance of Towers Perrin in assessing the value and cost of various proposed compensation arrangements. Towers Perrin is engaged by, and reports directly to, the committee.

In developing its compensation objectives, the committee compared our compensation levels with those of a group of 14 companies for 2007, and 17 companies for 2008, or collectively, the peer group. This benchmarking is done with respect to each of the key annual elements of our executive compensation programs discussed above (salary, STI and LTI compensation), as well as the compensation of individual executives based on their position in the overall compensation hierarchy. The committee uses data from the peer group to establish a dollar target level for each key element to deliver compensation to each executive at approximately the 50th percentile of the peer group, with adjustments made based on the executive s individual performance. Targeting the 50th percentile helps ensure that our compensation practices will be competitive in terms of attracting and retaining executive talent, while performance based compensation provides for variations due to superior or sub-par performance. Because compensation for the peer group is for prior periods, the committee attempts to anticipate future movements in compensation levels when it sets compensation targets. For example, when setting compensation for 2007, the most recent compensation information available was from the 2006 proxy statements for compensation paid in 2005. As more up to date information becomes available, it is reviewed by the committee to evaluate whether future compensation plans should be adjusted to take unanticipated changes in actual compensation of the peer group into account.

The 2007 peer group was comprised of the following companies:

| | | |
|---|---|---|
| Unit Corporation | St. Mary Land & Exploration | Cabot Oil & Gas Corporation |
| Penn Virginia Corporation | Whiting Petroleum Corporation | Range Resources Corporation |
| Encore Acquisition Company | Berry Petroleum Company | Bill Barrett Corporation |
| Quicksilver Resources | Clayton Williams Energy | Brigham Exploration Company |
| Forest Oil Corporation | Comstock Resources | |

For determination of 2008 compensation, Forest Oil Corporation, Range Resources and Quicksilver Resources were eliminated from the group because they had grown much larger than our company. Six additions were made to the group, Venoco, Rosetta Resources, Petroquest Energy, Delta Petroleum, Parallel Petroleum and Carrizo Oil & Gas, to help keep the median revenue and market capitalization of the group consistent with our company. The committee believes that the peer group represents companies with similar operations, of similar complexity, and with which we believe we compete for executive talent.

The following chart shows the comparison by category for the median compensation for the five highest paid executives combined of the peer group based on 2006 compensation adjusted for projected inflation increases, the target compensation levels set by the committee for 2007, and the actual compensation paid in 2007. The compensation above the target level reflects the achievement of the maximum target for production growth and the committee s assessment of performance for the discretionary portion of the STI, and the increase in stock price between the average stock price in December 2006 (which is used to determine the number of shares awarded for the LTI compensation) and the stock price on the date the awards were finalized.

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*Review of Overall Compensation*

The committee reviews for each of the executive officers the total dollar value of the officer s annual compensation, including salary, STI compensation, LTI compensation, perquisites, deferred compensation accruals and other compensation. The committee also reviews shareholdings and accumulated unrealized gains under prior equity-based compensation awards, and amounts payable to the executive officer upon termination of the executive s employment under various different circumstances, including retirement and termination in connection with a change in control. See 2007 Summary Compensation Table below.

*Consideration of Prior Compensation*

While the committee considers all compensation previously paid to the executive officers, including amounts realized or realizable under prior equity-based compensation awards, the committee believes that current compensation practices must be competitive to retain the executives in light of prevailing market practices and to motivate the future performance of the executive officers. Accordingly, wealth accumulation through our superior past performance is not punished through reductions in current compensation levels.

***Elements Of Executive Compensation***

*Overview*

To achieve the objectives of the executive compensation program, the committee uses four elements of compensation in varying proportions for the different executive officers. These elements are base salary, STI, LTI, and other benefits. The committee uses cash payments (base salary and STI), awards tied to our stock (LTI, which we also refer to as equity-based compensation) and non-cash benefits in its overall compensation packages. The committee balances salary and performance-based compensation, and cash and non-cash compensation, in a manner it believes best serves the objectives of our compensation program. The committee allocates among the different elements of compensation in a manner similar to the median allocation of the peer group, based on the level of the executive s position. Generally, it is the policy of the committee that, as income levels increase, a greater proportion of the executive s income should be in the form of STI and LTI compensation. For example our Chief Executive Officer receives a higher percentage of his compensation in the form of short and long term incentives compared to other executives, as is the case of chief executive officers in the peer group. The following table shows the breakdown of target compensation among the three elements for 2007 and 2008 for each executive officer.

| | Target Compensation for Elements as a Percentage of Total Target Compensation | | | | | |
|---|---|---|---|---|---|---|
| | 2007 | | | 2008 | | |
| **Name** | **Base Salary** | **Bonus Target** | **Equity Target** | **Base Salary** | **Bonus Target** | **Equity Target** |
| Steven R. Williams | 33% | 24% | 43% | 27% | 24% | 49% |
| Thomas E. Riley(1) | 36% | 22% | 42% | | | |
| Richard W. McCullough(2) | 40% | 20% | 40% | 29% | 27% | 44% |
| Eric R. Stearns | 36% | 23% | 41% | 33% | 20% | 47% |
| Barton R. Brookman, Jr.(3) | | | | 40% | 20% | 40% |
| Daniel W. Amidon(4) | | | | 40% | 20% | 40% |
| Darwin L. Stump | 44% | 22% | 34% | 40% | 20% | 40% |

(1) Mr. Riley resigned as our President effective March 9, 2008.
(2) Mr. McCullough was selected as successor to our Chief Executive Officer upon Mr. Williams retirement, anticipated to be in August 2008.
(3) Mr. Brookman was appointed to the executive position of Senior Vice President on March 8, 2008.
(4) Mr. Amidon joined us in July 2007 as General Counsel.

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*Base Salary*

The compensation committee annually reviews the base salaries of our Chief Executive Officer and our other executive officers. Salaries are also reviewed in the case of promotions or other significant changes in responsibilities. In each case, the committee takes into account the results achieved by the executive, his or her future potential, scope of responsibilities and experience, and competitive salary practices of the peer group. Base salary is intended to provide a baseline of compensation that is not contingent upon our performance.

After reviewing the peer group salary levels and considering individual performance, the committee established base salary increases for 2007 of 7.2% for our Chief Executive Officer and between 0% and 8.2% for our other executive officers. The total salary compensation of the executive officers approximated the mean of the peer group, although the spread between the highest and lowest is less than the peer group. For 2008, the committee established base salary increases of 8.1% for our Chief Executive Officer and between 3.2% and 44.7% for other executive officers. Mr. McCullough s base salary was increased by 44.7% to reflect the additional responsibilities he has assumed as President and the anticipated further increase in responsibilities upon his assumption of the Chief Executive Officer position later in the year. Annual base salaries for the executive officers for 2007 and 2008 are shown in the following table:

| | Annual Base Salaries | |
|---|---|---|
| **Name** | **2007** | **2008** |
| Steven R. Williams | $ 370,000 | $ 400,000 |
| Thomas E. Riley | 292,500 | |
| Richard W. McCullough | 235,000 | 340,000 |
| Eric R. Stearns | 271,500 | 305,000 |
| Barton R. Brookman, Jr. | 200,000 | 250,000 |
| Daniel W. Amidon | 210,000 | 227,500 |
| Darwin L. Stump | 220,500 | 227,500 |

*Short-Term Incentives*

Annual STI are tied to our overall performance for the fiscal year, as measured against objective criteria set by the committee, as well as the committee s assessment of our performance and individual performance of each executive. For 2007, at least 40% of the target STI payments are performance based awards measured against objective criteria established early in the fiscal year for all named executives except Mr. Stump. The remainder was awarded at the discretion of the committee based on its assessment of company and executive performance. For 2007 and 2008, 100% of Mr. Stump s STI is discretionary and for the other executive officers, STI performance based award percentages will be 70% of the total target STI. The compensation committee has decided to maintain discretion over STI bonus amounts for Mr. Stump to emphasize the focus of his role in 2007 and 2008 on the continued development of the accounting functions of our company rather than on production targets and overall financial performance. The committee, comprised entirely of independent directors, believes that some discretion with respect to individual awards is desirable to compensate for unusual and unexpected events, and as a result does not set specific performance targets for 30% of the target STI in 2008.

Target STI payments, expressed as a percentage of base salary, are set for each executive officer prior to the beginning of the fiscal year based on job responsibilities. STI payments for the year may range from zero up to 180% of the executive officer s base salary, based on the achievement of the objective criteria for performance based payments and the assessment by the committee for the balance. For fiscal year 2007 target STI awards for the executive officers ranged from 50% to 75% of salary. In 2008 target STI awards for the executive officers range from 50% to 90% of salary, which is in line with the peer group compensation.

With respect to the executive officers, the committee establishes formulae to determine the percentage of the target annual incentive payment that may be payable for the fiscal year. The committee does not have the

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discretion to change any objective criteria once they have been established. However, the committee does retain discretion over 60% (100% for Mr. Stump) of the total target STI in 2007 to allow some flexibility to award superior, or reflect the effect of sub-par, personal performance that may not be captured by the financial and operating criteria. In 2008 the committee established objective criteria for 70% of the total STI for all executives except Mr. Stump, where it will continue to maintain discretion over 100% of the STI award. In addition, the committee has the authority to recommend to the Board compensation for unusual circumstances. In July of 2007 we hired Dan Amidon as general counsel under an employment agreement that called for STI of up to 75% of his annual salary, prorated for the term of service. As a result of Mr. Amidon s outstanding performance and contributions the committee awarded Mr. Amidon total STI compensation equal to 100% of his salary (reduced pro rata for the partial year worked). The following table sets forth the STI threshold, target and maximum levels for 2007 and 2008 for the executives expressed as a percentage of base salary.

| | Short-Term Incentive Compensation(1) | | | | | |
|---|---|---|---|---|---|---|
| | 2007 % of Base Salary | | | 2008 % of Base Salary | | |
| Name | Threshold | Target | Stretch | Threshold | Target | Stretch |
| Steven R. Williams | 0% | 75% | 150% | 0% | 90% | 180% |
| Thomas E. Riley | 0% | 62.5% | 125% | | | |
| Richard W. McCullough | 0% | 50% | 100% | 0% | 90% | 180% |
| Eric R. Stearns | 0% | 62.5% | 125% | 0% | 62.5% | 125% |
| Barton R. Brookman, Jr. | | | | 0% | 50% | 100% |
| Daniel W. Amidon | 0% | 50% | 75% | 0% | 50% | 100% |
| Darwin L. Stump | | | | | | |

(1) Percentages apply to all executive officers with the exception of Mr. Stump, 100% of his STI was and is discretionary. Additionally, Mr. Brookman was not eligible for STI compensation until March 2008.

*Long-Term Incentives*

The committee s practice has been to determine the dollar amount of target equity compensation and to then grant equity-based compensation that has a fair value equal to that amount. To provide consistency from year-to-year and to avoid questions about timing of awards, the committee uses a consistent period to value the awards when determining the number of shares in the award, the average daily price in December of the year prior to the award year. The 2007 awards were determined using the fair value of the awards based on the average daily closing price of our stock in December 2006, with average December 2007 prices being used to determine the awards for 2008. At the committee s direction Towers Perrin calculated the fair value utilizing methods they have developed for use with these types of equity valuations, including taking into account the probability and/or timing of vesting under the performance criteria for the LTIP shares and the other restricted stock. For the purpose of recording an expense for financial reporting purposes, the awards are valued based on the market price at the time the award is finalized.

In April 2007, we corrected an administrative error in the stock option exercise price of shares awarded the executive officers in March 2006, none of which were exercised at the time. The administrative error related to the use of the closing price of our common stock on the day prior to the award, rather than the closing price on the day of the award in accordance with our 2004 Long-Term Equity Compensation Plan. We identified the need for the correction, and the effect of the correction was not material to the fair value of the awards, either at the time of the award or the time of the correction.

In 2007, a percentage of the equity-based compensation awards are LTIP shares with the percentage increasing for more highly compensated executives, and the balance of the awards are time vesting restricted stock. For example, 50% of the Chief Executive Officer s equity-based compensation in 2007 consisted of LTIP shares, in contrast to 40% for the President and 30% for the Chief Accounting Officer. The following table

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summarizes LTI awards for 2007 and 2008, and the second table summarizes the target prices for the performance vesting of the LTIP awards.

| | Long-Term Incentive Compensation | | | | | |
|---|---|---|---|---|---|---|
| | 2007 | | | 2008 | | |
| Name | Percent of Salary | Percent of Value from Time Vesting Restricted Stock | Percent of Value from LTIP Stock | Percent of Salary | Percent of Value from Time Vesting Restricted Stock | Percent of Value from LTIP Stock |
| Steven R. Williams | 175% | 50% | 50% | 175% | 0% | 100% |
| Thomas E. Riley | 145% | 60% | 40% | | | |
| Richard W. McCullough | | | | | | |