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.

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.

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.

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.

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 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.

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:
	senior in right of payment to all existing and future subordinated indebtedness of that subsidiary guarantor;
	equal in right of payment to all existing and future senior indebtedness of that subsidiary guarantor; and
	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:
	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.

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.

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.

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 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 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;

- 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.

				Floors		Ceilings		Swaps (Fixed Prices)	
Commodity/ Index/Area	Month Set	Month	Gross Monthly Quantity Gas-MMbtu Oil-Bbls	Net Monthly Quantity Gas-MMbtu Oil-Bbls	Floor Price	Net Monthly Quantity Gas-MMbtu Oil-Bbls	Ceiling Price	Net Monthly Quantity Gas-MMbtu Oil-Bbls	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)			
Commodity/ Index/Area	Month Set	Month	Gross Monthly Quantity Gas-MMbtu Oil-Bbls	Net Monthly Quantity Gas-MMbtu Oil-Bbls	Floor Price	Net Monthly Quantity Gas-MMbtu Oil-Bbls	Ceiling Price	Net Monthly Quantity 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,		Change	
	2008	2007	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.

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%

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

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

	Year Ended December 31, 2007	Year Ended December 31, 2006
	(per Mcfe)	
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

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

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

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

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

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

General and Administrative Expense

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

	Year Ended December 31,	Change

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

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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** *(in thousands)*	**3-5 years**	**More than 5 years**
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.

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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

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 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.

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.

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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.

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

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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.

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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 38th percentile to 60th percentile of the comparable peer group executive (41st 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, 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

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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.

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 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

Name	2007 Percent of Salary	2007 Percent of Value from Time Vesting Restricted Stock	2007 Percent of Value from LTIP Stock	2008 Percent of Salary	2008 Percent of Value from Time Vesting Restricted Stock	2008 Percent of Value from LTIP Stock
Steven R. Williams	175%	50%	50%	175%	0%	100%
Thomas E. Riley	145%	60%	40%			
Richard W. McCullough				150%	50%	50%
Eric R. Stearns	140%	60%	40%	145%	50%	50%
Barton R. Brookman, Jr.				100%	50%	50%
Daniel W. Amidon				100%	50%	50%
Darwin L. Stump	90%	70%	30%	75%	50%	50%

LTIP Target Prices(1)

Year of Award	Approximate Growth Target	Target Price			Percent Vested if Target Attained(2)
2007					
		2009	**2010**	**2011**	
	12%	$ 60.00	$ 67.50	$ 75.00	50%
	16%	67.50	77.50	90.00	75%
	20%	75.00	90.00	107.50	100%
2008					
		2010	**2011**	**2012**	
	12%	$ 80.50	$ 90.00	$ 101.00	50%
	16%	89.50	103.50	120.00	75%
	20%	99.00	118.50	142.50	100%

(1) Growth target percentages and target prices are based on the average closing price of our common stock during the preceding December for each of the years.

(2) Performance shares will vest for a performance period only if the target price is met or exceeded for such period. Performance shares vested for a performance period shall not be subject to divestment in the event the share price subsequently decreases below the threshold in a subsequent period.

Retirement Plans

We have a combined 401(k) and qualified profit sharing plan for all of our employees including the executive officers. The plan provides for discretionary matching contributions. Generally, we match employee 401(k) contributions dollar for dollar up to 10% of the employee s compensation and then match 20% for contributions above 10% of the employees compensation up to the maximum allowable limits under the Internal Revenue Code. Our profit sharing contribution is discretionary and for 2007 was equal to 1% of our consolidated net income. In addition there was a carryover contribution earned in 2006 of $1.1 million. Total company contributions, to both 401(k) and profit sharing, to the plan for 2007 were $2.5 million.

Under their current employment agreements, each of the named executive officers also earns the right to future payments following his or her retirement or other departure from our company. For each year worked

under his current agreement, Mr. Williams earns an annual retirement benefit equal to $500 times the number of his full years of service times 10 ($500 per year of service for 10 years). Following the termination of his service to our company, the cumulative total of the calculated annual retirement benefits is disbursed in ten equal annual installments. For 2007, the retirement benefit was $120,000 ($12,000 per year for 10 years) and for 2008, the retirement benefit will be $125,000 ($12,500 per year for 10 years) if Mr. Williams is employed by us for the full year, but no additional benefit will be earned if he retires before the end of the year as planned. Mr. Williams total cumulative retirement benefit, under this plan, at December 31, 2007, was $450,000 ($45,000 per year for 10 years). Mr. Williams also receives a lifetime healthcare benefit under his employment agreement; we have recorded an accumulated postretirement obligation of $296,819 as of December 31, 2007, related to this benefit. Each of the other executive officers, under their respective employment agreements, annually earns a retirement benefit equal to $75,000 ($7,500 per year for 10 years). Following their termination of service to our company, their cumulative total annual retirement benefit will be disbursed in ten equal annual installments. As of December 31, 2007, for Mr. Stearns and Mr. Stump, the total cumulative benefit, including the 2007 increment, was $300,000 ($30,000 per year for 10 years). As of December 31, 2007, Mr. McCullough s total cumulative benefit, including the 2007 increment, was $75,000 ($7,500 per year for 10 years).

Additionally, under his previous employment agreement, Mr. Williams earned supplemental retirement benefits. The prior agreement requires us to pay Mr. Williams an annual sum of $40,000 per year for the ten year period following his retirement (an aggregate of $400,000). This benefit was fully vested on December 31, 2003. The amount of the annual benefit is increased by 10.75% compounded annually for the period after December 31, 2003. Under provisions of his previous employment agreement, Mr. Williams may elect to defer payment up to five years following his retirement. In the event of deferral of payment following retirement the amount of the annual benefit will be increased by 10.75% compounded annually. As of December 31, 2007, the amount of this benefit is $601,893 (or $60,189 per year for 10 years). In the event of change in control the benefits due under this agreement will be accelerated and due immediately.

Other Compensation and Benefits

We also provide certain other benefits to its executive officers that are not tied to any formal individual or Company performance criteria and are intended to be part of a competitive overall compensation program. Each of the executive officers has 1) a company vehicle (or vehicle allowance) that they use for company business, and are allowed to use for personal uses as well, 2) coverage under our medical plan and reimbursement of medical expenses not covered by the plan, 3) the right to be reimbursed for one Board-approved club membership, 4) reimbursement of the cost of a $1 million life insurance policy, and 5) reimbursement of the cost of disability insurance. Given the importance of the executives and their good health to our success and the achievement of our business goals, the compensation committee believes that the medical insurance and reimbursement encourage the executives to seek appropriate medical assistance. The other benefits are commonly provided to executives and are necessary to create a competitive compensation package.

Termination Benefits including Change in Control Payments

The compensation provisions in the event of a change in control serve to lessen the potential negative impact of a change in control on the executive officers and to lessen the potential conflict between the best interest of the shareholders and that of the executives. The committee believes this is desirable, in combination with significant stock ownership, to encourage the executives to consider possible change in control situations that might benefit our shareholders.

The committee also believes that severance benefits for senior management should reflect the fact that it may be difficult for employees to find comparable employment within a short period of time. They also should disentangle us from the former employee as soon as practicable. For instance, while it is possible to provide salary continuation to an employee during the job search process, which in some cases may be less expensive than a lump-sum severance payment, a lump-sum severance payment is preferable in order to most cleanly sever

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the relationship as soon as practicable. We have entered into employment agreements with each of the executive officers that include change in control provisions. These agreements provide for the continued employment of the executives for a period of two years following a change in control of our company. These agreements are intended to retain the executives and provide continuity of management in the event of an actual or threatened change in the control of our company and ensure that the executive s compensation and benefits expectations would be satisfied in such event.

Where the termination is without cause or the executive officer terminates employment for good reason, the severance plan provides for benefits equal to three times the sum of: a) the executive officer s highest base salary during the previous two years of employment immediately preceding the termination date, plus b) the highest bonus paid to the executive officer during the same two year period. The executive officer is also entitled to 1) vesting of any unvested equity compensation, 2) reimbursement for any unpaid expenses, 3) retirement benefits earned under the current or previous agreements, 4) continued coverage under our medical plan for up to 18 months, and 5) payment of any earned, unpaid bonus amounts. In addition, a terminated executive officer is entitled to receive any benefits that he otherwise would have been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated. The committee believes that these termination benefits are comparable to the general practice among similar companies, although it has not conducted a study to confirm this.

Good reason includes 1) assignment to the executive of duties materially and adversely inconsistent with his position, duties, responsibilities and status with our company, 2) an adverse change in the executive s position with our company, 3) a change in control of our company, 4) a decrease of the executive officer s base salary, 5) a material reduction in the benefits provided by us, 6) our requirement for the executive officer to be based anywhere outside of Bridgeport, West Virginia, 7) our failure to obtain a satisfactory agreement from any successor or assignee to assume and agree to our obligations under the employment agreement, or 8) any other material breach of the employment agreement by us.

We may terminate any of the executive officers for just cause, which is defined in the employment agreements to include 1) a failure by the executive to perform his duties, 2) conduct by the executive that results in consequences which are materially adverse to us, monetarily or otherwise, 3) a guilty plea or conviction of a felony, or 4) a material breach of the terms of the employment agreement by the executive officer. If an executive officer is terminated for just cause, we are required to pay the executive officer his base salary through the termination date plus any bonus (only for periods completed and accrued, but not paid), incentive, deferred, retirement or other compensation, and provide any other benefits, which have been earned or become payable as of the termination date but which have not yet been paid or provided.

If an executive officer voluntarily terminates his employment for other than good reason, he is entitled to receive 1) the base salary, bonus and incremental retirement payment prorated for the portion of the year that the executive officer is employed by us, 2) any incentive, deferred or other compensation which has been earned or has become payable, but which has not yet been paid under the schedule originally contemplated in the agreement under which they were granted or in full without discount within 60 days of the termination date at our discretion, 3) any unpaid expense reimbursement upon presentation by the executive officer of an accounting of such expenses in accordance with our normal practices, and 4) any other payments for benefits earned under the employment agreement or company plans.

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The table below provides information regarding the amounts each of the executive officers would be eligible to receive if a termination event had occurred as of December 31, 2007:

	Termination Benefits			
Name	Retirement or Voluntary Termination by Executive	Termination For Cause by Company	Change in Control or Termination Without Cause or Good Reason by Executive	Death or Disability(1)
Steven R. Williams(2)	$ 4,117,113	$ 3,867,363	$ 8,101,899	$ 5,449,275
Thomas E. Riley	647,637	461,168	3,252,448(3)	1,705,198
Richard W. McCullough	311,606	205,856	1,493,174	656,674
Eric R. Stearns	625,325	472,606	3,010,848	1,579,098
Darwin L. Stump	502,231	336,856	2,294,578	1,181,053

(1) In the event of death or disability, the termination benefits would consist of (i) the base salary and bonus for the portion of the year the executive officer is employed by us; (ii) the base salary that would have been earned for six months after termination; (iii) immediate vesting of all equity and option awards; (iv) the payment of deferred retirement compensation based upon the schedule originally contemplated in the deferred retirement compensation agreement or in a lump-sum no later than two and one-half months following the close of the calendar year in which the death or disability occurred; (v) reimbursement for any unpaid expenses; (vi) and benefits earned under the 401(k) and profit sharing plan; and (vii) continued coverage under our medical plan, life time coverage for Mr. Williams and for up to 18 months for all other named executive officers.

(2) Includes (i) the estimated lifetime value of medical benefits for Mr. Williams and/or his spouse; and (ii) a deferred retirement compensation benefit related to a prior employment agreement.

(3) This benefit is calculated as of December 31, 2007. The value of Mr. Riley s actual severance benefit upon termination for good reason effective March 9, 2008, was higher than this amount was primarily because the actual severance was based on 2008 salary ($315,000) and on a higher annual bonus.

Executive and Director Share Retention and Ownership Guidelines

In order to promote equity ownership and further align the interests of management with our shareholders, the committee has adopted share retention and ownership guidelines for senior management and non-employee directors. Under these guidelines, executive officers and non-employee directors are required to achieve and continue to maintain a significant ownership position, as follows:

Chief Executive Officer	3 times salary
Other Executive Officers	2 times salary
Non-Employee Directors	1 times retainer

The committee periodically reviews share ownership levels of the persons subject to these guidelines. Shares held by the executive officers and shares held indirectly through our 401(k) plan are included in determining an executive officer s share ownership. Shares underlying stock options, including vested options, as well as unvested restricted stock, are not included. Mr. McCullough who was hired in November 2006, Mr. Amidon who was hired in July 2007, and Mr. Brookman, who was named as an Executive officer in March 2008, have not yet met the holding requirement. In addition the two new directors appointed in 2007, have not yet met the requirement. All other executive officers and non-employee directors have achieved shareholdings in excess of the applicable multiple set forth above.

Our insider trading policy expressly prohibits officers, directors, employees and associates from engaging in options, puts, calls or other transactions that are intended to hedge against the economic risk of owning shares of our common stock.

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Employment Agreements

We entered into employment agreements with Messrs. Williams, Riley, Stearns and Stump effective January 1, 2004, Mr. McCullough effective November 13, 2006, Mr. Amidon on July 2, 2007, and Mr. Brookman on July 11, 2007. The initial term of the agreements is for two years and they are automatically extended for an additional 12 months beginning on the first anniversary of the effective date and on each successive anniversary unless either party cancels. The employment agreements provide for the base annual salary to be reviewed annually (see Base Salary discussion above).

Each employment agreement provides for an annual performance bonus as determined by the compensation committee and is based in part upon written objective criteria and in part upon the discretion of the committee. The annual performance bonus earned is calculated as a percentage, as determined by the committee, of the executive officers base salary.

Each employment agreement contains a standard non-disclosure covenant and, also, provides that the executive officer is prohibited during the term of his employment and for a period of one year following his termination from engaging in any business that is competitive with our oil and gas drilling business. Additionally, the employment agreements state that the executive officer must devote substantially all of his business time, best efforts and attention to promote and advance our business. The executive officer may not be employed in any other business activity, other than with our company, during the term of the employment agreement, whether or not such activity is pursued for gain, profit or other pecuniary advantage without approval by the compensation committee of the Board. This restriction will not prevent the executive officer from investing his personal assets in a business which does not compete with us or our affiliates, and where such investment will not require services of any significance on the part of the executive officer in the operation of the affairs of the business.

Other Agreements and Arrangements

Prior to 2007 executive officers could invest in a Board-approved executive drilling program at our cost. Effective with the 2007 partnership the Board eliminated this executive officer investment program, although there were some carryover drilling from the 2006 program paid in 2007. During 2007, Messrs. Williams and Riley invested approximately $20,000, and $7,000, respectively. Other investors participating in drilling with us are generally charged a profit or markup above the cost of the wells; for example, the markup on company-sponsored partnerships is approximately 15% of the cost of the wells. As a result, the executive officers realize a benefit not generally available to other investors. The Board believes that having the executive officers invest in wells with us and other investors helps to create a commonality of interests much like share ownership creates a commonality of interests between the shareholders and executive officers.

Internal Revenue Code Section 162(m)

We are aware of Internal Revenue Code Section 162(m), which generally limits the deductibility of executive pay in excess of one million dollars, and which specifies the requirements for the performance-based exemption from this limit. Elements of the executive compensation program are indeed performance-based, and vehicles such as stock options are believed to qualify as performance-based under Section 162(m). Other aspects of the executive compensation program may not qualify as performance-based, such as time-based restricted stock and our annual incentive plan because the committee prefers the ability to exercise discretion in evaluating a portion of participants performance. The financial implications of a potential lost deduction are not expected to be material. The committee will continue to monitor its position on the impact of Section 162(m) for our executive compensation programs.

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Executive Compensation

2007 Summary Compensation Table

The following table provides summary compensation information for our Chief Executive Officer, our Chief Financial Officer, and our three most highly compensated executive officers, other than our Chief Executive Officer and Chief Financial Officer, whose total compensation exceeded $100,000 in 2007. We refer to these persons collectively as the named executive officers.

Name and Principal Position(1)	Year	Salary	Bonus(2)	Stock Awards(3)	Option Awards(4)	Non-Equity Incentive Plan Compensation(5)	Nonqualified Deferred Compensation(6)	All Other Compensation(7)	Total Compensation
Steven R. Williams	2007	$ 370,000	$ 249,750	$ 184,470	$ 34,609	$ 222,000	$ 140,312	$ 64,860(8)	$ 1,266,001
Chairman, Chief Executive Officer and Director	2006	345,000	155,250	163,023	54,546	362,250	88,438	37,778	1,206,285
Thomas E. Riley	2007	292,500	186,469	255,255	35,146	124,312	32,674	24,663	951,019
President and Director	2006	272,000	81,600	107,580	35,977	190,400	30,824	9,357	727,738
Richard W. McCullough	2007	235,000	105,750	46,390	17,532	94,000	30,555	13,625	542,852
Vice Chairman, Chief Financial Officer and Director	2006	32,237	83,000	5,928	2,289		3,848		127,302
Eric R. Stearns	2007	271,500	152,719	229,360	31,723	135,750	23,033	20,669	864,754
Executive Vice President, Exploration and Development	2006	251,000	175,300	98,318	32,806	175,700	21,730	17,773	772,627
Darwin L. Stump	2007	220,500	165,375	144,275	26,843		27,433	11,413	595,839
Chief Accounting Officer	2006	220,500	33,075	85,963	28,484	154,350	25,880	17,610	565,862

(1) The listed positions are those held as of December 31, 2007.
(2) Represents the discretionary based amounts paid under our annual STI bonus plan. For a discussion of the bonus plan, see the Compensation Discussion and Analysis set forth above.
(3) Represents compensation expense recorded by us pursuant to FAS 123(R) related to outstanding restricted stock awards. For information regarding the determination of such expense, please refer to Note 9 to our consolidated financial statements included in this prospectus.
(4) Represents compensation expense recorded by us pursuant to FAS 123(R) related to outstanding stock options. For information regarding the determination of such expense, please refer to Note 9 to our consolidated financial statements included in this prospectus.
(5) Represents the performance based amounts earned under our annual STI bonus plan. For a discussion of the bonus plan, see the Compensation Discussion and Analysis set forth above.
(6) Represents the present value of the current year benefit earned related to the deferred compensation retirement plan.
(7) All other compensation includes insurance and medical reimbursements, social fringe benefits such as club dues and athletic event tickets, the value for the personal use of company automobiles and discounts related to company-sponsored drilling programs.
(8) Includes, in addition to other compensation items discussed in (7) above, $37,845 for post retirement medical benefits.

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2007 Grants of Plan-Based Awards Table

Name	Grant Date	Estimated Future Payouts Under Non-Equity Incentive Plan Awards[1] Threshold	Target	Maximum	Estimated Future Payouts Under Equity Incentive Plan Awards (Number of Shares)[2] Threshold	Target	Maximum	All Other Stock Awards: Number of Shares Awarded[3]	Grant Date Fair Value of Stock and Option Awards
Steven R. Williams	2/20/2007	$	$	$				8,484	$ 436,332(4)
	2/20/2007					7,341	14,683		529,616(5)
	3/29/2007		277,500	555,000					
Thomas E. Riley	2/20/2007							6,669	342,987(4)
	2/20/2007					3,847	7,694		277,523(5)
	3/29/2007		182,812	365,625					
Richard W. McCullough	2/20/2007								(4)
	2/20/2007								(5)
	3/29/2007		117,500	235,000					
Eric R. Stearns	2/20/2007							5,976	307,346(4)
	2/20/2007					3,447	6,895		248,703(5)
	3/29/2007		169,688	339,375					
Darwin L. Stump	2/20/2007							3,640	187,205(4)
	2/20/2007					1,350	2,700		97,389(5)

(1) Represents STI compensations award, or cash incentive awards, computed as described above in Compensation Discussion and Analysis Short-Term Incentives.

(2) Represents market-based restricted stock awards under our 2004 Long-Term Equity Compensation Plan. For a discussion of our Long-Term Incentive Plan, see the Compensation Discussion and Analysis set forth above.

(3) Represents time-based restricted stock awards under our 2004 Long-Term Equity Compensation Plan. For a discussion of our Long-Term Incentive Plan, see the Compensation Discussion and Analysis set forth above.

(4) Grant date fair value is computed by multiplying the number of shares awarded by the closing price of our stock on the date of grant, which was $51.43. Mr. McCullough was first employed by us in November 2006, at which time he received a time based stock award for his initial year of employment and therefore was not awarded shares in 2007.

(5) Grant date fair value is computed by multiplying the number of shares awarded by the grant date fair market value as computed utilizing the Monte Carlo pricing model, which was $36.07 per share. Mr. McCullough was first employed by us in November 2006, at which time he was not eligible to receive market based stock awards until he completed his initial year of employment.

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Outstanding Equity Awards at 2007 Fiscal Year-End Table

	Option Awards				Restricted Stock Awards			
	Number of Securities Underlying Unexercised Options Held at December 31, 2007							
Name	Exercisable	Unexercisable	Exercise Price	Expiration Date	Number of Shares of Stock That Have Not Vested	Market Value of Shares That Have Not Vested(1)	Equity Incentive Plan Awards: Number of Unearned Shares That Have Not Vested(2)	Equity Incentive Plan Awards: Market Value of Unearned Shares That Have Not Vested(1)
Steven R. Williams	4,402	1,468(3)	$ 37.15	12/13/2014	47,528(4)	$ 2,810,331	14,683	$ 868,206
	1,879	5,638(5)	44.95	3/16/2016				
Thomas E. Riley	2,917	973(6)	37.15	12/13/2014	12,623(7)	746,398	7,694(8)	454,946
	1,234	3,705(6)	44.95	3/16/2016				
Richard W. McCullough	833	2,500(5)	43.60	11/14/2016	3,192(5)	188,743		
Eric R. Stearns	2,752	918(3)	37.15	12/13/2014	11,327(9)	669,766	6,895	407,701
	1,093	3,282(5)	44.95	3/16/2016				
Darwin L. Stump	2,587	863(3)	37.15	12/13/2014	8,121(10)	480,195	2,700	159,651
	880	2,643(5)	44.95	3/16/2016				

(1) The market value of shares is based on the closing price of our common stock on December 31, 2007, which was $59.13 per share.
(2) Represents LTIP shares that will vest based on the achievement of certain price appreciation targets for our common stock as discussed in the Compensation Discussion and Analysis set forth above.
(3) 100% of these options are scheduled to vest in 2008.
(4) 36,491 shares are scheduled to vest in 2008, including 30,000 shares expected to vest in August upon Mr. Williams retirement as Chief Executive Officer, 4,458 shares in each of the years 2009 and 2010, and 2,121 shares in 2011.
(5) Approximately 33% of these options will vest in each of the years 2008 through 2010.
(6) 100% of these options vested in March 2008 pursuant to Mr. Riley s separation agreement.
(7) 100% of these shares vested in March 2008 pursuant to Mr. Riley s separation agreement.
(8) 3,078 shares vested in March 2008 pursuant to Mr. Riley s separation agreement; the remaining 4,616 shares were forfeited.
(9) 4,124 shares are scheduled to vest in 2008, 2,854 shares in 2009, 2,855 shares in 2010 and 1,494 shares in 2011.
(10) 3,200 shares are scheduled to vest in 2008, 2,005 shares in 2009, 2,006 shares in 2010 and 910 shares in 2011.

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2007 Options Exercises and Stock Vested Table

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise	Value Realized on Exercise	Number of Shares Acquired on Vesting	Value Realized on Vesting(1)
Steven R. Williams		$	4,369(2)	$ 235,009
Thomas E. Riley			2,882(3)	155,079
Richard W. McCullough			1,064(4)	56,115
Eric R. Stearns			2,630(5)	141,863
Darwin L. Stump			2,290(6)	124,277

(1) Based on the closing price of our common stock on the date of vesting, March 16, 2007 of $49.86 per share, November 14, 2007 of $52.74 per share, and December 13, 2007, of $58.31 per share.
(2) Includes 2,337 shares vesting on March 16, 2007 and 2,032 shares vesting on December 13, 2007.
(3) Includes 1,535 shares vesting on March 16, 2007 and 1,347 shares vesting on December 13, 2007.
(4) Includes 1,064 shares vesting on November 14, 2007.
(5) Includes 1,360 shares vesting on March 16, 2007 and 1,270 shares vesting on December 13, 2007.
(6) Includes 1,095 shares vesting on March 16, 2007 and 1,195 shares vesting on December 13, 2007.

2007 Nonqualified Deferred Compensation Table

Name	Executive Contributions in 2007	Company Contributions in 2007(1)	Aggregate Earnings in 2007(2)	Aggregate Withdrawals/ Distributions	Aggregate Balance at December 31, 2007
Steven R. Williams	$	$ 140,312(3)	$ 45,289	$	$ 940,422
Thomas E. Riley		32,674	5,548		130,693
Richard W. McCullough		30,555	231		34,634
Eric R. Stearns		23,033	3,911		92,133
Darwin L. Stump		27,433	4,658		109,732

(1) Company contributions include the present value cost of providing the defined compensation payout over a ten year period. Since this is a self funded deferred compensation plan, our additional annual deferred compensation expense, less the interest component noted as aggregate earnings above, equals the increase in the accrued company contributions that are required to fund the plan. These annual amounts are a component of the executive officers 2007 compensation and are included in the 2007 Summary Compensation Table.
(2) Aggregate earnings consist of interest income earned on the beginning of the year compensation balance at a 6% interest rate. These earnings are not included in the 2007 Summary Compensation Table as they are not above market rate.
(3) Mr. Williams received deferred compensation benefits from both the current deferred compensation plan for all named executive officers, as well as a prior retirement plan.

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Equity Compensation Plan Information

The following table summarizes information related to our equity compensation plans under which our equity securities are authorized for issuance as of December 31, 2007.

Plan category	Number of securities to be issued upon exercise of outstanding options(1)	Weighted-average exercise price of outstanding options	Number of securities remaining available for future issuance under equity compensation plans(2)
Equity compensation plans approved by security holders:			
1999 Incentive Stock Option and Non-Qualified Stock Option Plan	11,000	$ 3.88	
2004 Long-Term Equity Compensation Plan	40,567	41.59	473,600
2005 Non-Employee Director Restricted Stock Plan			13,844
Total equity compensation plans approved by security holders	51,567		487,444
Equity compensation plans not approved by security holders			
Total	51,567	32.72	487,444

(1) Excludes 31,972 shares of common stock to be issued upon the obtainment of specified performance goals over a specified period of time.
(2) Excludes the number of securities to be issued upon exercise of outstanding options and performance shares subject to certain performance goals over a specified period of time.

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CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Policies and Procedures with Respect to Transactions with Related Persons

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

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

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

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

During the year ended December 31, 2007, there was no transaction or series of transactions, or any currently proposed transaction, in which the amount involved exceeds $120,000 and in which any director, executive officer, nominee, holder of more than 5% of our common stock or any member of the immediate family of any of the foregoing persons had or will have a direct or indirect material interest.

Waiver of Potential Conflict of Interest

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

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

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SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The following table sets forth certain information regarding ownership of our common stock as of May 1, 2008, by (a) each person known by us to own beneficially more than 5% of the outstanding shares of common stock; (b) each director of PDC; (c) each executive officer; and (d) all directors and executive officers as a group. As of May 1, 2008, 14,848,954 common shares of PDC were issued and outstanding. Except as otherwise indicated, the address for each of the named security holders is 120 Genesis Boulevard, Bridgeport, West Virginia 26330.

Name and Address of Beneficial Owner	Number of Shares Beneficially Owned	Percent of Shares Beneficially Owned
Steinberg Asset Management, LLC 12 East 49th Street New York, NY 10017	1,531,255 (1)	10.3%
FMR LLC 82 Devonshire Street Boston, MA 02109	1,243,080 (2)	8.4%
Dimensional Fund Advisors LP 1299 Ocean Avenue Santa Monica, CA 90401	1,238,580 (3)	8.3%
Kayne Anderson Rudnick Investment Management, LLC 1800 Avenue of the Stars, 2nd Floor Los Angeles, CA 90067	917,857 (4)	6.2%
Barclays Global Investors, NA 45 Fremont Street San Francisco, CA 94105	842,151 (5)	5.7%
Steven R. Williams	295,984 (6)	2.0%
Eric R. Stearns	65,573 (7)	*
Richard W. McCullough	2,364 (8)	*
Darwin L. Stump	22,546 (9)	*
Daniel W. Amidon	(10)	*
Barton R. Brookman, Jr.	7,182 (11)	*
Vincent F. D Annunzio	19,758 (12)	*
Jeffrey C. Swoveland	14,802 (13)	*
Kimberly Luff Wakim	5,432 (14)	*
David C. Parke	5,558 (15)	*
Anthony J. Crisafio	3,035	*
Joseph E. Casabona	1,355	*
Larry F. Mazza	1,355	*
All directors and executive officers as a group (13 persons)	444,944 (16)	3.0%

* Less than 1%

(1) According to the Schedule 13G filed by Steinberg Asset Management, LLC with the SEC on February 11, 2008.

(2) According to the Schedule 13G filed by FMR LLC with the SEC on May 12, 2008.

(3) According to the Schedule 13G filed by Dimensional Fund Advisors LP with the SEC on February 6, 2008.

(4) According to the Schedule 13G filed by Kayne Anderson Rudnick Investment Management, LLC with the SEC on February 8, 2008.

(5) According to the Schedule 13G filed by Barclays Global Investors, NA with the SEC on February 6, 2008.

(6) Excludes 43,070 restricted shares subject to vesting greater than 60 days after May 1, 2008; includes 8,160 shares subject to options exercisable within 60 days of May 1, 2008.

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(7) Excludes 21,778 restricted shares subject to vesting greater than 60 days after May 1, 2008; includes 4,939 shares subject to options exercisable within 60 days of May 1, 2008.

(8) Excludes 22,126 restricted shares subject to vesting greater than 60 days after May 1, 2008; includes 833 shares subject to options exercisable within 60 days of May 1, 2008.

(9) Excludes 7,807 restricted shares subject to vesting greater than 60 days after May 1, 2008; includes 4,348 shares subject to options exercisable within 60 days of May 1, 2008.

(10) Excludes 11,511 restricted shares subject to vesting greater than 60 days after May 1, 2008.

(11) Excludes 19,893 restricted shares subject to vesting greater than 60 days after May 1, 2008.

(12) Excludes 4,559 common shares purchased pursuant to the Non-Employee Director Deferred Compensation Plan.

(13) Excludes 114 common shares purchased pursuant to the Non-Employee Director Deferred Compensation Plan.

(14) Excludes 1,046 common shares purchased pursuant to the Non-Employee Director Deferred Compensation Plan.

(15) Excludes 571 common shares purchased pursuant to the Non-Employee Director Deferred Compensation Plan.

(16) Excludes 126,185 restricted shares subject to vesting greater than 60 days after May 1, 2008 and 6,290 common shares purchased pursuant to the Non-Employee Director Deferred Compensation Plan; includes 18,280 shares subject to options exercisable within 60 days of May 1, 2008.

DESCRIPTION OF OTHER INDEBTEDNESS

Senior Secured Credit Facility

General

On November 4, 2005, we entered into an amended and restated senior credit agreement with a syndicate of lenders led by JPMorgan Chase Bank, N.A., as administrative agent, and BNP Paribas, as syndication agent and joint lead arranger. Pursuant to amendments on August 9, 2007, October 16, 2007, and November 6, 2007, Wachovia Bank, National Association, Guaranty Bank, FSB, Bank of Oklahoma, Morgan Stanley Bank, Royal Bank of Canada and The Royal Bank of Scotland, plc, were added as lenders. The senior credit agreement is a five-year senior revolving credit facility that provides for as much as $400 million in borrowing capacity, depending on a number of factors, including the projected value of our proven natural gas and oil reserves. The borrowing base is redetermined on a semi-annual basis, but may be reduced upon the occurrence of certain events, including the issuance of certain indebtedness. Our borrowing base under the credit facility as of March 31, 2008 was $234.1 million. We are required to pay a commitment fee of 0.25% to 0.375% per annum on the unused portion of the credit facility.

As of March 31, 2008, there was no amount outstanding under the credit facility. Borrowings under the credit facility will mature on November 4, 2010. The terms of the facility are as described below.

Guarantees and Security

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

Interest and Fees

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

Covenants and Events of Default

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

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

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THE EXCHANGE OFFER

Exchange Terms

Old notes in an aggregate principal amount of $203,000,000 are currently issued and outstanding. The maximum aggregate principal amount of new notes that will be issued in exchange for old notes is $203,000,000. The terms of the new notes and the old notes are substantially the same in all material respects, except that the new notes will not contain terms with respect to transfer restrictions, registration rights and payments of liquidated damages.

The new notes will bear interest at a rate of 12% per year, payable semi-annually on February 15 and August 15 of each year, beginning on August 15, 2008. Holders of new notes will receive interest from February 8, 2008, the date of original issuance of the old notes. Holders of new notes will not receive any interest on old notes tendered and accepted for exchange. In order to exchange your old notes for transferable new notes in the exchange offer, you will be required to make the following representations, which are included in the letter of transmittal:

- any new notes that you receive will be acquired in the ordinary course of your business;
- you are not participating, and have no arrangement or understanding 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.

Upon the terms and subject to the conditions set forth in this prospectus and in the letter of transmittal, we will accept for exchange any old notes properly tendered in the exchange offer, and the exchange agent will deliver the new notes promptly after the expiration date of the exchange offer.

If you tender your old notes, you will not be required to pay brokerage commissions or fees or, subject to the instructions in the letter of transmittal, transfer taxes with respect to the exchange of the old notes in connection with the exchange offer. We will pay all charges, expenses and transfer taxes in connection with the exchange offer, other than the taxes described below under Transfer Taxes.

We make no recommendation to you as to whether you should tender or refrain from tendering all or any portion of your existing old notes into this exchange offer. In addition, no one has been authorized to make this recommendation. You must make your own decision whether to tender into this exchange offer and, if so, the aggregate amount of old notes to tender after reading this prospectus and the letter of transmittal and consulting with your advisors, if any, based on your financial position and requirements.

Expiration Date; Extensions; Termination; Amendments

The exchange offer expires at 5:00 p.m., New York City time, on June 23, 2008, unless we extend the exchange offer, in which case the expiration date will be the latest date and time to which we extend the exchange offer.

We expressly reserve the right, so long as applicable law allows:

- to delay our acceptance of old notes for exchange;

to terminate the exchange offer if any of the conditions set forth under Conditions of the Exchange Offer exist;

- to waive any condition to the exchange offer;
- to amend any of the terms of the exchange offer; and
- to extend the expiration date and retain all old notes tendered in the exchange offer, subject to your right to withdraw your tendered old notes as described under Withdrawal of Tenders.

Any waiver or amendment to the exchange offer will apply to all old notes tendered, regardless of when or in what order the old notes were tendered. If the exchange offer is amended in a manner that we think constitutes a material change, or if we waive a material condition of the exchange offer, we will promptly disclose the amendment or waiver by means of a prospectus supplement that will be distributed to the registered holders of the old notes, and we will extend the exchange offer to the extent required by Rule 14e-1 under the Exchange Act.

We will promptly follow any delay in acceptance, termination, extension or amendment by oral or written notice of the event to the exchange agent, followed promptly by oral or written notice to the registered holders. Should we choose to delay, extend, amend or terminate the exchange offer, we will have no obligation to publish, advertise or otherwise communicate this announcement, other than by making a timely release to an appropriate news agency.

In the event we terminate the exchange offer, all old notes previously tendered and not accepted for payment will be returned promptly to the tendering holders.

In the event that the exchange offer is withdrawn or otherwise not completed, new notes will not be given to holders of old notes who have validly tendered their old notes.

Resale of New Notes

Based on interpretations of the SEC staff set forth in no action letters issued to third parties, we believe that new notes issued under the exchange offer in exchange for old notes may be offered for resale, resold and otherwise transferred by you without compliance with the registration and prospectus delivery requirements of the Securities Act, if:

- you are acquiring new notes in the ordinary course of your business;
- you are not participating, and have no arrangement or understanding with any person to participate, in the distribution of the new notes;
- you are not our affiliate within the meaning of Rule 405 under the Securities Act; and
- you are not a broker-dealer who purchased old notes directly from us for resale pursuant to Rule 144A or any other available exemption under the Securities Act.

If you tender old notes in the exchange offer with the intention of participating in any manner in a distribution of the new notes:

- you cannot rely on those interpretations by the SEC staff, and
- you must comply with the registration and prospectus delivery requirements of the Securities Act in connection with a secondary resale transaction and that such a secondary resale transaction must be covered by an effective registration statement containing the

selling security holder information required by Item 507 or 508, as applicable, of Regulation S-K.

Only broker-dealers that acquired the old notes as a result of market-making activities or other trading activities may participate in the exchange offer. Each broker-dealer that receives new notes for its own account in exchange for old notes, where such old notes were acquired by such broker-dealer as a result of market-making

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activities or other trading activities, must acknowledge that it will deliver a prospectus in connection with any resale of the new notes. Please read the section captioned Plan of Distribution for more details regarding the transfer of new notes.

Acceptance of Old Notes for Exchange

We will accept for exchange old notes validly tendered pursuant to the exchange offer, or defectively tendered, if such defect has been waived by us. We will not accept old notes for exchange subsequent to the expiration date of the exchange offer. Tenders of old notes will be accepted only in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof.

We expressly reserve the right, in our sole discretion, to:

- delay acceptance for exchange of old notes tendered under the exchange offer, subject to Rule 14e-1 under the Exchange Act, which requires that an offeror pay the consideration offered or return the securities deposited by or on behalf of the holders promptly after the termination or withdrawal of a tender offer, or

- terminate the exchange offer and not accept for exchange any old notes not theretofore accepted for exchange, if any of the conditions set forth below under Conditions of the Exchange Offer have not been satisfied or waived by us or in order to comply in whole or in part with any applicable law.

In all cases, new notes will be issued only after timely receipt by the exchange agent of certificates representing old notes, or confirmation of book-entry transfer, a properly completed and duly executed letter of transmittal, or a manually signed facsimile thereof, and any other required documents. For purposes of the exchange offer, we will be deemed to have accepted for exchange validly tendered old notes, or defectively tendered old notes with respect to which we have waived such defect, if, as and when we give oral, confirmed in writing, or written notice to the exchange agent. Promptly after the expiration date, we will deposit the new notes with the exchange agent, who will act as agent for the tendering holders for the purpose of receiving the new notes and transmitting them to the holders. The exchange agent will deliver the new notes to holders of old notes accepted for exchange after the exchange agent receives the new notes.

If, for any reason, we delay acceptance for exchange of validly tendered old notes or we are unable to accept for exchange validly tendered old notes, then the exchange agent may, nevertheless, on our behalf, retain tendered old notes, without prejudice to our rights described under Expiration Date; Extensions; Termination; Amendments, Withdrawal of Tenders and Conditions of the Exchange Offer, subject to Rule 14e-1 under the Exchange Act, which requires that an offeror pay the consideration offered or return the securities deposited by or on behalf of the holders thereof promptly after the termination or withdrawal of a tender offer.

If any tendered old notes are not accepted for exchange for any reason, or if certificates are submitted evidencing more old notes than those that are tendered, certificates evidencing old notes that are not exchanged will be returned, without expense, to the tendering holder, or, in the case of old notes tendered by book-entry transfer into the exchange agent s account at a book-entry transfer facility under the procedure set forth under Procedures for Tendering Old Notes Book-Entry Transfer, such old notes will be credited to the account maintained at such book-entry transfer facility from which such old notes were delivered, unless otherwise requested by such holder under Special Delivery Instructions in the letter of transmittal, promptly following the expiration date or the termination of the exchange offer.

Tendering holders of old notes exchanged in the exchange offer will not be obligated to pay brokerage commissions or transfer taxes with respect to the exchange of their old notes other than as described in Transfer Taxes or in Instruction 7 to the letter of transmittal. We will pay all other charges and expenses in connection with the exchange offer.

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Procedures for Tendering Old Notes

Any beneficial owner whose old notes are registered in the name of a broker, dealer, commercial bank, trust company or other nominee or held through a book-entry transfer facility and who wishes to tender old notes should contact such registered holder promptly and instruct such registered holder to tender old notes on such beneficial owner s behalf.

Tender of Old Notes Held Through Depository Trust Company

The exchange agent and Depository Trust Company, or DTC, have confirmed that the exchange offer is eligible for the DTC s automated tender offer program. Accordingly, DTC participants may electronically transmit their acceptance of the exchange offer by causing DTC to transfer old notes to the exchange agent in accordance with DTC s automated tender offer program procedures for transfer. DTC will then send an agent s message to the exchange agent.

The term agent s message means a message transmitted by DTC, received by the exchange agent and forming part of the book-entry confirmation, which states that DTC has received an express acknowledgment from the participant in DTC tendering old notes that are the subject of that book-entry confirmation that the participant has received and agrees to be bound by the terms of the letter of transmittal, and that we may enforce such agreement against such participant. In the case of an agent s message relating to guaranteed delivery, the term means a message transmitted by DTC and received by the exchange agent which states that DTC has received an express acknowledgment from the participant in DTC tendering old notes that they have received and agree to be bound by the notice of guaranteed delivery.

Tender of Old Notes Held in Certificated Form

For a holder to validly tender old notes held in certificated form:

- the exchange agent must receive at its address set forth in this prospectus a properly completed and validly executed letter of transmittal, or a manually signed facsimile thereof, together with any signature guarantees and any other documents required by the instructions to the letter of transmittal, and

- the exchange agent must receive certificates for tendered old notes at such address, or such old notes must be transferred pursuant to the procedures for book-entry transfer described below.

A confirmation of such book-entry transfer must be received by the exchange agent prior to the expiration date of the exchange offer. A holder who desires to tender old notes and who cannot comply with the procedures set forth herein for tender on a timely basis or whose old notes are not immediately available must comply with the procedures for guaranteed delivery set forth below.

Letters of transmittal and old notes should be sent only to the exchange agent, and not to us or to DTC.

The method of delivery of old notes, letters of transmittal and all other required documents to the exchange agent is at the election and risk of the holder tendering old notes. Delivery of such documents will be deemed made only when actually received by the exchange agent. If such delivery is by mail, we suggest that the holder use properly insured, registered mail with return receipt requested, and that the mailing be made sufficiently in advance of the expiration date of the exchange offer to permit delivery to the exchange agent prior to such date. No alternative, conditional or contingent tenders of old notes will be accepted.

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Signature Guarantee

Signatures on the letter of transmittal must be guaranteed by an eligible institution unless:

- the letter of transmittal is signed by the registered holder of the old notes tendered therewith, or by a participant in one of the book-entry transfer facilities whose name appears on a security position listing it as the owner of those old notes and the new notes are to be issued directly to such registered holder(s), or, if tendered by a participant in one of the book-entry transfer facilities, any old notes for principal amounts not tendered or not accepted for exchange are to be credited to the participant s account at the book-entry transfer facility, and neither the Special Issuance Instructions nor the Special Delivery Instructions box on the letter of transmittal has been completed, or

- the old notes are tendered for the account of an eligible institution.

An eligible institution is a firm that is a member of a registered national securities exchange or of the National Association of Securities Dealers, Inc., a commercial bank or a trust company having an office or correspondent in the United States or an eligible guarantor institution within the meaning of Rule 17Ad-15 under the Exchange Act.

Book-Entry Transfer

The exchange agent will seek to establish a new account or utilize an existing account with respect to the old notes at DTC promptly after the date of this prospectus. Any financial institution that is a participant in the DTC system and whose name appears on a security position listing as the owner of the old notes may make book-entry delivery of old notes by causing DTC to transfer such old notes into the exchange agent s account. **However, although delivery of old notes may be effected through book-entry transfer into the exchange agent s account at DTC, a properly completed and validly executed letter of transmittal, or a manually signed facsimile thereof, must be received by the exchange agent at one of its addresses set forth in this prospectus on or prior to the expiration date of the exchange offer, or else the guaranteed delivery procedures described below must be complied with.** The confirmation of a book-entry transfer of old notes into the exchange agent s account at DTC is referred to in this prospectus as a book-entry confirmation. Delivery of documents to DTC in accordance with DTC s procedures does not constitute delivery to the exchange agent.

Guaranteed Delivery

If you wish to tender your old notes and:

(1) certificates representing your old notes are not lost but are not immediately available,

(2) time will not permit your letter of transmittal, certificates representing your old notes and all other required documents to reach the exchange agent on or prior to the expiration date of the exchange offer, or

(3) the procedures for book-entry transfer cannot be completed on or prior to the expiration date of the exchange offer,

you may nevertheless tender if all of the following conditions are complied with:

- your tender is made by or through an eligible institution; and

- on or prior to the expiration date of the exchange offer, the exchange agent has received from the eligible institution a properly completed and validly executed notice of guaranteed delivery, by manually signed facsimile transmission, overnight courier, registered or certified mail or hand delivery, in substantially the form provided with this prospectus. The notice of guaranteed delivery must:

(a) set forth your name and address, the registered number(s) of your old notes and the principal amount of old notes tendered;

(b) state that the tender is being made thereby;

(c) guarantee that, within three New York Stock Exchange trading days after the expiration date, the letter of transmittal or facsimile thereof properly completed and validly executed, together with certificates representing the old notes, or a book-entry confirmation, and any other documents required by the letter of transmittal and the instructions thereto, will be deposited by the eligible institution with the exchange agent; and

(d) the exchange agent receives the properly completed and validly executed letter of transmittal or facsimile thereof with any required signature guarantees, together with certificates for all old notes in proper form for transfer, or a book-entry confirmation, and any other required documents, within three New York Stock Exchange trading days after the expiration date.

Other Matters

New notes will be issued in exchange for old notes accepted for exchange only after timely receipt by the exchange agent of:

- certificates for (or a timely book-entry confirmation with respect to) your old notes,
- a properly completed and duly executed letter of transmittal or facsimile thereof with any required signature guarantees, or, in the case of a book-entry transfer, an agent s message, and
- any other documents required by the letter of transmittal.

We will determine, in our sole discretion, all questions as to the form of all documents and the validity, eligibility, including time of receipt, acceptance and withdrawal of all tenders of old notes. Our determination will be final and binding on all parties. **Alternative, conditional or contingent tenders of old notes will not be considered valid. We reserve the absolute right to reject any or all tenders of old notes not properly tendered or the acceptance of which, in our opinion, would be unlawful. We also reserve the right to waive any defects, irregularities or conditions of tender as to particular old notes.**

Our interpretation of the terms and conditions of the exchange offer, including the instructions in the letter of transmittal, will be final and binding.

Any defect or irregularity in connection with tenders of old notes must be cured within the time we determine, unless waived by us. We will not consider the tender of old notes to have been validly made until all defects and irregularities have been waived by us or cured. Neither we, the exchange agent, or any other person will be under any duty to give notice of any defects or irregularities in tenders of old notes, or will incur any liability to holders for failure to give any such notice.

Withdrawal of Tenders

Except as otherwise provided in this prospectus, you may withdraw your tender of old notes at any time prior to the expiration date.

For a withdrawal to be effective:

- the exchange agent must receive a written notice of withdrawal at one of the addresses set forth below under Exchange Agent, or
- you must comply with the appropriate procedures of DTC s automated tender offer program system.

Any notice of withdrawal must:

specify the name of the person who tendered the old notes to be withdrawn, and

identify the old notes to be withdrawn, including the principal amount of the old notes.

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If old notes have been tendered pursuant to the procedure for book-entry transfer described above, any notice of withdrawal must specify the name and number of the account at DTC to be credited with the withdrawn old notes and otherwise comply with the procedures of DTC.

We will determine all questions as to validity, form, eligibility and time of receipt of any withdrawal notices. Our determination will be final and binding on all parties. We will deem any old notes so withdrawn not to have been validly tendered for exchange for purposes of the exchange offer.

Any old notes that have been tendered for exchange but that are not exchanged for any reason will be returned to their holder without cost to the holder or, in the case of old notes tendered by book-entry transfer into the exchange agent s account at DTC according to the procedures described above, such old notes will be credited to an account maintained with DTC for the old notes. This return or crediting will take place as soon as practicable after withdrawal, rejection of tender or termination of the exchange offer. You may retender properly withdrawn old notes by following one of the procedures described under Procedures for Tendering Old Notes at any time on or prior to the expiration date.

Conditions of the Exchange Offer

Notwithstanding any other provisions of the exchange offer, if, on or prior to the expiration date, we determine, in our reasonable judgment, that the exchange offer, or the making of an exchange by a holder of old notes, would violate applicable law or any applicable interpretation of the staff of the SEC, we will not be required to accept for exchange, or to exchange, any tendered old notes. We may also terminate, waive any conditions to or amend the exchange offer. In addition, we may postpone the acceptance for exchange of tendered old notes, subject to Rule 14e-1 under the Exchange Act, which requires that an offeror pay the consideration offered or return the securities deposited by or on behalf of the holders thereof promptly after the termination or withdrawal of the exchange offer.

Transfer Taxes

We will pay all transfer taxes applicable to the transfer and exchange of old notes pursuant to the exchange offer. If, however:

- new notes or old notes for principal amounts not exchanged, are to be delivered to or registered or issued in the name of, any person other than the registered holder of the old notes tendered;

- tendered certificates for old notes are registered in the name of any person other than the person signing any letter of transmittal; or

- a transfer tax is imposed for any reason other than the transfer and exchange of old notes to us or our order pursuant to the exchange offer,

the amount of any such transfer taxes, whether imposed on the registered holder or any other person, will be payable by the tendering holder prior to the issuance of the new notes or delivery or registering of the old notes.

Consequences of Failing to Exchange

If you do not exchange your old notes for new notes in the exchange offer, you will remain subject to the restrictions on transfer of the old notes:

- as set forth in the legend printed on the old notes as a consequence of the issuance of the old notes pursuant to the exemptions from, or in transactions not subject to, the registration requirements of the Securities Act and applicable state securities laws; and

- otherwise set forth in the offering memorandum distributed in connection with the private offering of the old notes.

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In general, you may not offer or sell the old notes unless the transaction is registered under the Securities Act, or if the offer or sale is exempt from registration under the Securities Act and applicable state securities laws. Except as required by the registration rights agreement, we do not intend to register resales of the old notes under the Securities Act.

Accounting Treatment

The new notes will be recorded at the same carrying value as the old notes, as reflected in our accounting records on the date of the exchange. Accordingly, we will not recognize any gain or loss for accounting purposes upon the consummation of the exchange offer. We will amortize the expenses of the exchange offer over the term of the new notes.

Exchange Agent

The Bank of New York has been appointed as exchange agent for the exchange offer. You should direct questions and requests for assistance, requests for additional copies of this prospectus, the letter of transmittal or any other documents to the exchange agent. You should send certificates for old notes, letters of transmittal and any other required documents to the exchange agent addressed as follows:

The exchange agent for the exchange offer is:

THE BANK OF NEW YORK

By Registered or Certified Mail:

The Bank of New York

101 Barclay Street, 8W

New York, New York 10286

Attn: Corporate Trust Division Corporate Finance Unit

By Regular Mail/ Hand/ Overnight Delivery:

The Bank of New York

101 Barclay Street, Corporate Trust Services Window

New York, New York 10286

Attn: Corporate Trust Division Corporate Finance Unit

For Assistance Call:

(212) 815-3750

Fax Number (for eligible institutions only):

(212) 815-5704

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DESCRIPTION OF NOTES

We will issue the new notes under an indenture between us and The Bank of New York, a New York banking corporation, as trustee. The terms of the notes include those stated in the indenture and those made part of the indenture by reference to the Trust Indenture Act of 1939, as amended.

The following description is a summary of the material provisions of the indenture. It does not restate such agreement in its entirety. We urge you to read the indenture because it, and not this description, defines your rights as holders of the notes. Copies of the indenture are available as set forth below under Additional Information.

You can find the definitions of terms used in this description of notes below under the caption Definitions. Capitalized terms used in this description but not defined below under the caption Definitions have the meanings assigned to them in the indenture. In this description, the words PDC, we, us, and our refer only to Petroleum Development Corporation, and not to any of its Subsidiaries or Affiliates. This description assumes that all outstanding old notes will be exchanged for new notes in the exchange offer. Therefore, except where the context requires otherwise, all references to the notes in this description are to the new notes.

The registered holder of a note will be treated as the owner of it for all purposes. Only registered holders will have rights under the indenture.

Brief Description of the Notes and the Subsidiary Guarantees

The Notes

The notes will:

- be general unsecured, senior obligations of PDC;
- rank senior in right of payment to all existing and future subordinated indebtedness of PDC;
- rank *pari passu* in right of payment with any existing and future senior indebtedness of PDC; and
- rank effectively junior to PDC s existing and future secured indebtedness, including indebtedness under the Senior Credit Agreement, to the extent of the assets of PDC constituting collateral securing that indebtedness.

The Subsidiary Guarantees

Initially, the notes will not be guaranteed by any of our Subsidiaries. However, in the future, each of our Domestic Restricted Subsidiaries will be required to guarantee the notes if, on any date after the Issue Date, such Subsidiary both:

- Guarantees (or otherwise becomes liable for) Obligations under the Senior Credit Agreement; and
- constitutes a Material Subsidiary.

Each Subsidiary Guarantee will:

- be a general unsecured, senior obligation of the applicable Subsidiary Guarantor;

rank senior in right of payment to all existing and future subordinated indebtedness of such Subsidiary Guarantor;

rank *pari passu* in right of payment with any existing and future senior indebtedness of such Subsidiary Guarantor; and

rank effectively junior to all existing and future secured indebtedness of such Subsidiary Guarantor to the extent of the assets of such Subsidiary Guarantor constituting collateral securing that indebtedness.

As of the date of the indenture, all of our Subsidiaries were Restricted Subsidiaries. However, under the circumstances described below under the caption Covenants Designation of Restricted and Unrestricted Subsidiaries, we will be permitted to designate additional Subsidiaries as Unrestricted Subsidiaries. Our Unrestricted Subsidiaries will not be subject to many of the restrictive covenants in the indenture, and will not guarantee the notes.

Principal, Maturity and Interest

We will issue $203.0 million in aggregate principal amount of notes in the exchange offer. We may issue additional notes (*Additional Notes*) under the indenture from time to time after the exchange offer. Any issuance of Additional Notes is subject to all of the covenants in the indenture, including the covenant described below under the caption Covenants Incurrence of Indebtedness and Issuance of Preferred Stock. The notes and any Additional Notes subsequently issued under the indenture will be treated as a single class for all purposes under the indenture, including, without limitation, waivers, amendments, redemptions and offers to purchase. We may also issue other debt securities under the indenture. If issued, such other debt securities will not vote together with the notes on any matter. The notes will mature on February 15, 2018, and will be issued in denominations of $2,000 and integral multiples of $1,000 in excess of $2,000.

Interest on the notes will accrue at the rate of 12.0% per annum and will be payable semi-annually in arrears on February 15 and August 15, beginning on August 15, 2008; *provided*, *however*, that upon any failure by PDC for 60 days to comply with the covenant described under the caption Covenants Reports, the interest rate on the notes will increase by 0.50% per annum and remain at such increased rate thereafter, but only for as long as there is a continuing Default under such covenant, and upon resumption of compliance by PDC with such covenant, the interest rate will be reset as if the interest rate had never been increased pursuant to this provision. Interest on overdue principal, interest and Liquidated Damages, if any, will accrue at the applicable interest rate on the notes. PDC will make each interest payment to the holders of record of the notes on the immediately preceding February 1 and August 1. Any Liquidated Damages due will be paid on the same dates as interest on the notes. Interest on the notes will accrue from the date of original issuance or, if interest has already been paid, from the date it was most recently paid. Interest will be computed on the basis of a 360-day year comprised of twelve 30-day months. If a payment date is a Legal Holiday at a place of payment, payment may be made at that place on the next succeeding day that is not a Legal Holiday, and no interest shall accrue on such payment for the intervening period.

Methods of Receiving Payments on the Notes

If a holder of notes has given wire transfer instructions to PDC, PDC will pay all principal, interest and premium and Liquidated Damages, if any, on that holder s notes in accordance with those instructions. All other payments on the notes will be made at the office or agency of the paying agent and registrar, unless we elect to make interest payments by check mailed to the noteholders at their address set forth in the register of holders.

Paying Agent and Registrar

The trustee will initially act as paying agent and registrar for the notes. PDC may change the paying agent or registrar without prior notice to the holders of the notes, and PDC or any of the Restricted Subsidiaries may act as paying agent or registrar.

Transfer and Exchange

A holder may transfer or exchange notes in accordance with the indenture. The registrar and the trustee may require a holder, among other things, to furnish appropriate endorsements and transfer documents in connection with a transfer of the notes, and PDC may require a holder to pay any taxes and fees required by law or permitted by the indenture. PDC will not be required to transfer or exchange any note (or portion of a note) selected for redemption. Also, PDC will not be required to transfer or exchange any note for a period of 15 days before a selection of notes to be redeemed.

Subsidiary Guarantees of the Notes

Initially, the notes will not be guaranteed by any of our Subsidiaries. However, in the future, each of our Domestic Restricted Subsidiaries will be required to guarantee the notes if, on any date after the Issue Date, such Subsidiary both:

- Guarantees (or otherwise becomes liable for) Obligations under the Senior Credit Agreement; and

- constitutes a Material Subsidiary.

The Subsidiary Guarantees will be joint and several obligations of the Subsidiary Guarantors. The obligations of each Subsidiary Guarantor under its Subsidiary Guarantee will be limited as necessary to prevent that Subsidiary Guarantee from constituting a fraudulent conveyance under applicable law.

A Subsidiary Guarantor may not sell or otherwise dispose of all or substantially all of its assets to, or consolidate with or merge with or into (regardless of whether such Subsidiary Guarantor is the surviving Person), another Person, other than PDC or another Subsidiary Guarantor, unless:

(1) immediately after giving effect to that transaction, no Default or Event of Default exists; and

(2) either:

(a)(i) such Subsidiary Guarantor is the surviving Person or (ii) the Person acquiring the property in any such sale or disposition or the Person formed by or surviving any such consolidation or merger (if other than such Subsidiary Guarantor) assumes all the obligations of such Subsidiary Guarantor under the indenture (including its Subsidiary Guarantee) pursuant to a supplemental indenture satisfactory to the trustee; or

(b) the Net Proceeds of such sale or other disposition are applied in accordance with the applicable provisions of the indenture.

The Subsidiary Guarantee of a Subsidiary Guarantor will be released:

(1) in connection with any sale or other disposition of all or substantially all of the assets of such Subsidiary Guarantor (including by way of merger or consolidation) to a Person that is not (either before or after giving effect to such transaction) PDC or a Restricted Subsidiary, if the sale or other disposition does not violate the Asset Sale provisions of the indenture described below under the caption Repurchase at the Option of Holders Asset Sales;

(2) in connection with any sale or other disposition of all of the Capital Stock of such Subsidiary Guarantor to a Person that is not (either before or after giving effect to such transaction) PDC or a Restricted Subsidiary, if the sale or other disposition does not violate the provisions of the indenture described under Repurchase at the Option of Holders Asset Sales;

(3) if PDC designates any Restricted Subsidiary that is a Subsidiary Guarantor to be an Unrestricted Subsidiary in accordance with the applicable provisions of the indenture;

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(4) upon legal defeasance or satisfaction and discharge of the indenture as provided pursuant to the defeasance or satisfaction and discharge provisions of the indenture as described below under the captions Legal Defeasance and Covenant Defeasance and Satisfaction and Discharge;

(5) upon the liquidation or dissolution of such Subsidiary Guarantor, provided no Default or Event of Default occurs as a result thereof or has occurred or is continuing; or

(6) at such time as such Subsidiary Guarantor is no longer required to be a Subsidiary Guarantor pursuant to the covenant set forth under the caption Covenants Subsidiary Guarantees.

Optional Redemption

Except as described below, the notes are not redeemable until February 15, 2013. On and after February 15, 2013, PDC may redeem all or a part of the notes, from time to time upon not less than 30 nor more than 60 days prior notice, at the following redemption prices (expressed as a percentage of principal amount) plus accrued and unpaid interest and Liquidated Damages, if any, on the notes redeemed to the applicable redemption date (subject to the rights of holders of notes on the relevant record date to receive interest due on the relevant interest payment date), if redeemed during the twelve-month period beginning on February 15 of the years indicated below:

Year	Redemption Price
2013	106.000%
2014	104.000%
2015	102.000%
2016 and thereafter	100.000%

At any time or from time to time prior to February 15, 2013, PDC may also redeem all or a part of the notes, upon not less than 30 nor more than 60 days prior notice, at a redemption price equal to the Make-Whole Price, subject to the rights of holders of notes on the relevant record date to receive interest due on the relevant interest payment date.

Make-Whole Price with respect to any notes to be redeemed, means an amount equal to the greater of:

(1) 100% of the principal amount of such notes; and

(2) the sum of the present values of (a) the redemption price of such notes at February 15, 2013 (as set forth above) and (b) the remaining scheduled payments of interest from the redemption date to February 15, 2013 (not including any portion of such payments of interest accrued as of the redemption date) discounted back to the redemption date on a semi-annual basis (assuming a 360-day year consisting of twelve 30-day months) at the Treasury Rate (as defined below) *plus* 50 basis points;

plus, in the case of both (1) and (2), accrued and unpaid interest on such notes and Liquidated Damages, if any, to the redemption date.

Comparable Treasury Issue means, with respect to notes to be redeemed, the U.S. Treasury security selected by an Independent Investment Banker as having a maturity most nearly equal to the period from the redemption date to February 15, 2013, at the time of selection and in accordance with customary financial practice, in pricing new issues of corporate debt securities; *provided* that if such period is less than one year, then the U.S. Treasury security having a maturity of one year shall be used.

Comparable Treasury Price means, with respect to any redemption date, (1) the average of four Reference Treasury Dealer Quotations for such redemption date, after excluding the highest and lowest of such Reference Treasury Dealer Quotations, or (2) if the trustee obtains fewer than four such Reference Treasury Dealer Quotations, the average of all such Reference Treasury Dealer Quotations.

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Independent Investment Banker means Morgan Stanley & Co. Incorporated or J.P. Morgan Securities Inc. and their respective successors, or, if such firms or their respective successors, if any, as the case may be, are unwilling or unable to select the Comparable Treasury Issue, an independent investment banking institution of national standing appointed by PDC.

Reference Treasury Dealer means Morgan Stanley & Co. Incorporated or J.P. Morgan Securities Inc. and three additional primary Government Securities dealers in New York City (each a *Primary Treasury Dealer*) selected by PDC, and its successors; *provided*, *however*, that if any such firm or any such successor, as the case may be, shall cease to be a primary Government Securities dealer in New York City, PDC shall substitute therefor another Primary Treasury Dealer.

Reference Treasury Dealer Quotations means, with respect to each Reference Treasury Dealer and any redemption date, the average, as determined by the trustee, of the bid and asked prices for the Comparable Treasury Issue (expressed in each case as a percentage of its principal amount) quoted in writing to the trustee by such Reference Treasury Dealer at 5:00 p.m., New York City time, on the third Business Day preceding such redemption date.

Treasury Rate means, with respect to any redemption date, (1) the yield, under the heading which represents the average for the immediately preceding week, appearing in the most recently published statistical release designated H.15(159) or any successor publication that is published weekly by the Board of Governors of the Federal Reserve System and that establishes yields on actively traded U.S. Treasury securities adjusted to constant maturity under the caption *Treasury Constant Maturities*, for the maturity corresponding to the Comparable Treasury Issue (if no maturity is within three months before or after the stated maturity, yields for the two published maturities most closely corresponding to the Comparable Treasury Issue shall be determined, and the Treasury Rate shall be interpolated or extrapolated from such yields on a straight-line basis, rounding to the nearest month) or (2) if such release (or any successor release) is not published during the week preceding the calculation date or does not contain such yields, the rate per annum equal to the semi-annual equivalent yield to maturity of the Comparable Treasury Issue, calculated using a price for the Comparable Treasury Issue (expressed as a percentage of its principal amount) equal to the Comparable Treasury Price for such redemption date. The Treasury Rate shall be calculated on the third Business Day preceding the redemption date.

The notice of redemption with respect to the foregoing redemption need not set forth the Make-Whole Price but only the manner of calculation thereof. PDC will notify the trustee of the Make-Whole Price with respect to any redemption promptly after the calculation, and the trustee shall not be responsible for such calculation.

Prior to February 15, 2011, PDC may on any one or more occasions redeem up to 35% of the principal amount of the notes with all or a portion of the net cash proceeds of one or more Equity Offerings at a redemption price equal to 112.0% of the principal amount thereof, plus accrued and unpaid interest and Liquidated Damages, if any, on the notes redeemed to the redemption date (subject to the right of holders of record on the relevant record date to receive interest due on the relevant interest payment date); *provided* that

(1) at least 65% of the aggregate principal amount of the notes issued on the Issue Date (excluding notes held by PDC and its Subsidiaries) remains outstanding after each such redemption; and

(2) the redemption occurs within 180 days after the closing of such Equity Offering.

Notice of any redemption upon an Equity Offering may be given prior to the completion of the related Equity Offering, and any such redemption or notice may at PDC s discretion, be subject to one or more conditions precedent, including, but not limited to completion of the related Equity Offering.

Unless PDC defaults in the payment of the redemption price, interest and Liquidated Damages, if any, will cease to accrue on the notes or portions thereof called for redemption on the applicable redemption date.

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Selection and Notice

If less than all of the notes are to be redeemed at any time, the trustee will select notes for redemption on a pro rata basis unless otherwise required by law or applicable stock exchange requirements.

No notes of $2,000 or less can be redeemed in part. Notices of redemption will be mailed by first class mail at least 30 but not more than 60 days before the redemption date to each holder of notes to be redeemed at its registered address, except that redemption notices may be mailed more than 60 days prior to a redemption date if the notice is issued in connection with a defeasance of the notes or a satisfaction and discharge of the indenture.

If any note is to be redeemed in part only, the notice of redemption that relates to such note shall state the portion of the principal amount thereof to be redeemed. A new note in principal amount equal to the unredeemed portion thereof will be issued in the name of the holder thereof upon cancellation of the original note. Notes called for redemption become due on the date fixed for redemption. On and after the redemption date, interest ceases to accrue on notes or portions of notes called for redemption, unless PDC defaults in making the redemption payment. Any redemption or notice of redemption may, at our discretion, be subject to one or more conditions precedent and, in the case of a redemption with the net cash proceeds of an Equity Offering, be given prior to the completion of the related Equity Offering.

Open Market Purchases; No Mandatory Redemption or Sinking Fund

We may at any time and from time to time purchase notes in the open market or otherwise. We are not required to make mandatory redemption or sinking fund payments with respect to the notes.

Repurchase at the Option of Holders

Change of Control

If a Change of Control occurs, each holder of notes will have the right to require PDC to repurchase all or any part (equal to $1,000 or an integral multiple of $1,000) of that holder s notes pursuant to an offer (a *Change of Control Offer*) on the terms set forth in the indenture. In the Change of Control Offer, PDC will offer a payment in cash (the *Change of Control Payment*) equal to not less than 101% of the aggregate principal amount of notes repurchased plus accrued and unpaid interest and Liquidated Damages, if any, on the notes repurchased to the date of purchase (the *Change of Control Payment Date*), subject to the rights of holders of notes on the relevant record date to receive interest due on the relevant interest payment date. Within 30 days following any Change of Control, PDC will mail a notice to each holder describing the transaction or transactions that constitute the Change of Control and offering to repurchase notes on the Change of Control Payment Date specified in the notice, which date will be no earlier than 30 days and no later than 60 days from the date such notice is mailed, pursuant to the procedures required by the indenture and described in such notice. PDC will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with the repurchase of the notes as a result of a Change of Control. To the extent that the provisions of any securities laws or regulations conflict with the Change of Control provisions of the indenture, PDC will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under the Change of Control provisions of the indenture by virtue of such compliance.

On the Change of Control Payment Date, PDC will, to the extent lawful:

(1) accept for payment all notes or portions of notes properly tendered pursuant to the Change of Control Offer;

(2) deposit with the paying agent an amount equal to the Change of Control Payment in respect of all notes or portions of notes properly tendered; and

(3) deliver or cause to be delivered to the trustee the notes properly accepted together with an Officers Certificate stating the aggregate principal amount of notes or portions of notes being purchased by PDC.

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The paying agent will promptly mail or wire transfer to each holder of notes properly tendered the Change of Control Payment for such notes (or, if all the notes are then in global form, make such payment through the facilities of DTC), and the trustee will promptly authenticate and mail (or cause to be transferred by book entry) to each holder a new note equal in principal amount to any unpurchased portion of the notes surrendered, if any; *provided* that each such new note will be in a principal amount of $2,000 and integral multiples of $1,000 in excess of $2,000. Any note so accepted for payment will cease to accrue interest on and after the Change of Control Payment Date unless PDC defaults in making the Change of Control Payment. PDC will publicly announce the results of the Change of Control Offer on or as soon as practicable after the Change of Control Payment Date.

The provisions described herein that require PDC to make a Change of Control Offer following a Change of Control will be applicable regardless of whether any other provisions of the indenture are applicable. Except as described above with respect to a Change of Control, the indenture does not contain provisions that permit the holders of the notes to require that PDC repurchase or redeem the notes in the event of a takeover, recapitalization or similar transaction.

PDC will not be required to make a Change of Control Offer upon a Change of Control if (1) a third party makes the Change of Control Offer in the manner, at the times and otherwise in compliance with the requirements set forth in the indenture applicable to a Change of Control Offer made by PDC and purchases all notes properly tendered and not withdrawn under the Change of Control Offer, or (2) notice of redemption has been given pursuant to the indenture as described above under the caption Optional Redemption, unless and until there is a Default in payment of the applicable redemption price.

A Change of Control Offer may be made in advance of a Change of Control, and conditioned upon the occurrence of such Change of Control, if a definitive agreement is in place for the Change of Control at the time of making the Change of Control Offer. Notes repurchased by PDC pursuant to a Change of Control Offer will have the status of notes issued but not outstanding or will be retired and cancelled, at PDC s option. Notes purchased by a third party pursuant to the preceding paragraph will have the status of notes issued and outstanding.

The definition of Change of Control includes a phrase relating to the direct or indirect sale, lease, transfer, conveyance or other disposition of all or substantially all of the properties or assets of PDC and its Restricted Subsidiaries taken as a whole. Although there is a limited body of case law interpreting the phrase substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, the ability of a holder of notes to require PDC to repurchase its notes as a result of a sale, lease, transfer, conveyance or other disposition of less than all of the assets of PDC and its Restricted Subsidiaries taken as a whole to another Person or group may be uncertain.

In the event that holders of at least 90% of the aggregate principal amount of the outstanding notes accept a Change of Control Offer and PDC purchases all of the notes held by such holders, PDC will have the right, upon not less than 30 nor more than 60 days prior notice, given not more than 30 days following a Change of Control Payment Date, to redeem all, but not less than all, of the notes that remain outstanding at a redemption price equal to the Change of Control Payment plus, to the extent not included in the Change of Control Payment, accrued and unpaid interest and Liquidated Damages, if any, on the notes that remain outstanding, to the date of redemption (subject to the right of holders on the relevant record date to receive interest due on the relevant interest payment date).

Asset Sales

PDC will not, and will not permit any of its Restricted Subsidiaries to, consummate an Asset Sale unless:

(1) PDC (or the Restricted Subsidiary, as the case may be) receives consideration at least equal to the Fair Market Value of the assets or Equity Interests issued or sold or otherwise disposed of; and

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(2)(x) at least 75% of the consideration received in respect of such Asset Sale by PDC or such Restricted Subsidiary is in the form of cash or Cash Equivalents or (y) the Fair Market Value of all forms of consideration other than cash and Cash Equivalents received for all Asset Sales since the Issue Date does not exceed in the aggregate 10% of the Adjusted Consolidated Net Tangible Assets of PDC at the time each determination is made. For purposes of this provision, each of the following will be deemed to be cash:

(a) any liabilities, as shown on PDC s most recent consolidated balance sheet, of PDC or any Restricted Subsidiary (other than contingent liabilities and liabilities that are by their terms subordinated to the notes or any Subsidiary Guarantee) that are assumed by the transferee of any such assets or Equity Interests pursuant to (1) a customary novation agreement that releases PDC or such Restricted Subsidiary from further liability therefor or (2) an assignment agreement that includes, in lieu of such a release, the agreement of the transferee or its parent company to indemnify and hold harmless PDC or such Restricted Subsidiary from and against any loss, liability or other cost in respect of such assumed liability;

(b) any securities, notes or other obligations received by PDC or any such Restricted Subsidiary from such transferee that are converted by PDC or such Restricted Subsidiary into cash within 180 days after the date of the Asset Sale, to the extent of the cash received in that conversion; and

(c) any stock or assets of the kind referred to in clause (2) of the third paragraph of this covenant.

Notwithstanding the foregoing, the 75% limitation referred to above shall be deemed satisfied with respect to any Asset Sale in which the cash or Cash Equivalents portion of the consideration received therefrom, determined in accordance with the foregoing provision on an after-tax basis, is equal to or greater than what the after-tax proceeds would have been had such Asset Sale complied with the aforementioned 75% limitation.

Within 365 days after the receipt of any Net Proceeds from an Asset Sale or, if PDC has entered into a binding commitment or commitments with respect to any of the actions described in clauses (2) or (3) below, within the later of (x) 360 days after the receipt of any Net Proceeds from an Asset Sale or (y) 180 days after the entering into of such commitment or commitments, PDC (or the applicable Restricted Subsidiary, as the case may be) may apply such Net Proceeds:

(1) to repay Senior Debt;

(2) to invest in Additional Assets; or

(3) to make capital expenditures in respect of a Related Business of PDC or any of its Restricted Subsidiaries.

An amount equal to any Net Proceeds from Asset Sales that are not applied or invested as provided in clauses (1) through (3) above will constitute *Excess Proceeds*.

Within ten Business Days after the aggregate amount of Excess Proceeds exceeds $20.0 million, PDC will make an offer (an *Asset Sale Offer*) to all holders of notes and all holders of other Indebtedness that is *pari passu* with the notes containing provisions similar to those set forth in the indenture with respect to offers to purchase or redeem with the proceeds of sales of assets, to purchase the maximum principal amount of notes and such other *pari passu* Indebtedness that may be purchased out of the Excess Proceeds. The offer price in any Asset Sale Offer will be equal to 100% of the principal amount plus accrued and unpaid interest and Liquidated Damages, if any, to the date of purchase, and will be payable in cash. If any Excess Proceeds remain after consummation of an Asset Sale Offer, PDC or any Restricted Subsidiary may use those Excess Proceeds for any purpose not otherwise prohibited by the indenture. If the aggregate principal amount of notes and other *pari passu* Indebtedness tendered into such Asset Sale Offer exceeds the amount of Excess Proceeds, PDC will use the Excess Proceeds to purchase the notes and such other *pari passu* Indebtedness on a pro rata basis. Upon completion of each Asset Sale Offer, the amount of Excess Proceeds will be reset at zero.

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Notwithstanding the foregoing, the sale, conveyance or other disposition of all or substantially all of the assets of PDC and its Restricted Subsidiaries, taken as a whole, will be governed by the provisions of the indenture described under the caption Repurchase at the Option of Holders Change of Control and/or the provisions described under the caption Covenants Merger, Consolidation or Sale of Assets and not by the provisions of the Asset Sale covenant.

PDC will comply with the requirements of Rule 14e-1 under the Exchange Act and any other securities laws and regulations thereunder to the extent those laws and regulations are applicable in connection with each repurchase of notes pursuant to an Asset Sale Offer. To the extent that the provisions of any securities laws or regulations conflict with the Asset Sales provisions of the indenture, or compliance with the Asset Sales provisions of the indenture would constitute a violation of any such laws or regulations, PDC will comply with the applicable securities laws and regulations and will not be deemed to have breached its obligations under the Asset Sales provisions of the indenture by virtue of such compliance.

The Senior Credit Agreement contains, and future agreements may contain, prohibitions of certain events, including events that would constitute a Change of Control or an Asset Sale and including repurchases of or other prepayments in respect of the notes. The exercise by the holders of notes of their right to require PDC to repurchase the notes upon a Change of Control or an Asset Sale could cause a default under these other agreements, even if the Change of Control or Asset Sale itself does not, due to the financial effect of such repurchases on PDC or otherwise. In the event a Change of Control or Asset Sale occurs at a time when PDC is prohibited from purchasing notes, PDC could seek the consent of the applicable lenders to the purchase of notes or could attempt to refinance the Indebtedness that contain such prohibitions. If PDC does not obtain a consent or repay that Indebtedness, PDC will remain prohibited from purchasing notes. In that case, PDC s failure to purchase tendered notes would constitute an Event of Default under the indenture which could, in turn, constitute a default under other Indebtedness. Finally, PDC s ability to pay cash to the holders of notes upon a repurchase may be limited by PDC s then-existing financial resources. See Risk Factors Risks Related to the Notes and Our Indebtedness We may not be able to finance a change of control offer required by the indenture governing the notes.

Covenants

Restricted Payments

PDC will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly:

(1) declare or pay any dividend or make any other payment or distribution on account of PDC s or any of its Restricted Subsidiaries Equity Interests (including, without limitation, any payment in connection with any merger or consolidation involving PDC or any of its Restricted Subsidiaries) or to the direct or indirect holders of PDC s or any of its Restricted Subsidiaries Equity Interests in their capacity as such (other than dividends or distributions payable in Equity Interests (other than Disqualified Stock) of PDC and other than dividends or distributions payable to PDC or any Restricted Subsidiary);

(2) purchase, redeem or otherwise acquire or retire for value (including, without limitation, any such purchase, redemption, acquisition or retirement made in connection with any merger or consolidation involving PDC) any Equity Interests of PDC or any direct or indirect parent company of PDC;

(3) make any payment on or with respect to, or purchase, redeem, defease or otherwise acquire or retire for value any Subordinated Debt, except a payment of interest or principal at the Stated Maturity thereof (excluding (a) any intercompany Indebtedness between or among PDC and any of its Restricted Subsidiaries or (b) the purchase, repurchase or other acquisition of Subordinated Debt purchased in anticipation of satisfying a sinking fund obligation, principal installment or final maturity, in each case due within one year of the date of such purchase, repurchase or other acquisition); or

(4) make any Restricted Investment

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(all such payments and other actions set forth in clauses (1) through (4) above being collectively referred to as *Restricted Payments*), unless, at the time of and after giving effect to such Restricted Payment:

(1) no Default or Event of Default has occurred and is continuing or would occur as a consequence of such Restricted Payment;

(2) PDC would, at the time of such Restricted Payment and after giving pro forma effect thereto as if such Restricted Payment had been made at the beginning of the applicable four-quarter period, have been permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described below under the caption Incurrence of Indebtedness and Issuance of Preferred Stock; and

(3) such Restricted Payment, together with the aggregate amount of all other Restricted Payments made by PDC and its Restricted Subsidiaries since the Issue Date (excluding Restricted Payments permitted by clauses (2), (3), (4), (5), (6), (7), (8), (9), (12) and (14) of the next succeeding paragraph), is equal to or less than the sum, without duplication, of:

(a) 50% of the Consolidated Net Income of PDC for the period (taken as one accounting period) from the beginning of the first fiscal quarter commencing prior to the Issue Date to the end of PDC s most recently ended fiscal quarter for which internal financial statements are available at the time of such Restricted Payment (or, if such Consolidated Net Income for such period is a deficit, less 100% of such deficit); *plus*

(b) 100% of (A) (i) the aggregate net cash proceeds and (ii) the Fair Market Value of (x) marketable securities (other than marketable securities of PDC or an Affiliate of PDC), (y) Capital Stock of a Person (other than PDC or an Affiliate of PDC) engaged primarily in any Related Business and (z) other assets used or useful in any Related Business, in each case received by PDC since the Issue Date as a contribution to its common equity capital or from the issue or sale of Equity Interests of PDC (other than Disqualified Stock) or from the issue or sale of convertible or exchangeable Disqualified Stock or convertible or exchangeable debt securities of PDC that have been converted into or exchanged for such Equity Interests (other than Equity Interests (or Disqualified Stock or debt securities) sold to a Subsidiary of PDC), (B) with respect to Indebtedness that is incurred on or after the Issue Date, the amount by which such Indebtedness of PDC or any of its Restricted Subsidiaries is reduced on PDC s consolidated balance sheet upon the conversion or exchange after the Issue Date of any such Indebtedness into or for Equity Interests of PDC (other than Disqualified Stock), and (C) the aggregate net cash proceeds, if any, received by PDC or any of its Restricted Subsidiaries upon any conversion or exchange described in clause (A) or (B) above; *plus*

(c) with respect to Restricted Investments made by PDC and its Restricted Subsidiaries after the Issue Date, an amount equal to the sum, without duplication, of (A) the net reduction in such Restricted Investments in any Person resulting from (i) repayments of loans or advances, or other transfers of assets, in each case to PDC or any Restricted Subsidiary, (ii) other repurchases, repayments or redemptions of such Restricted Investments, (iii) the sale of any such Restricted Investment to a purchaser other than PDC or a Subsidiary of PDC or (iv) the release of any Guarantee (except to the extent any amounts are paid under such Guarantee) that constituted a Restricted Investment plus (B) with respect to any Unrestricted Subsidiary designated as such after the Issue Date is redesignated as a Restricted Subsidiary after the Issue Date, the Fair Market Value of PDC s Investment in such Subsidiary held by PDC or any of its Restricted Subsidiaries at the time of such redesignation; *plus*

(d) 100% of any dividends received by PDC or a Restricted Subsidiary after the Issue Date from an Unrestricted Subsidiary, to the extent such dividends were not otherwise included in the Consolidated Net Income of PDC for such period.

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The preceding provisions will not prohibit:

(1) the payment of any dividend or the consummation of any irrevocable redemption within 60 days after the date of declaration of the dividend or giving of the redemption notice, as the case may be, if at the date of declaration or notice, the dividend or redemption payment would have complied with the provisions of the indenture;

(2) the making of any Restricted Payment in exchange for, or out of the net cash proceeds from the substantially concurrent sale (other than to a Subsidiary of PDC) of, Equity Interests of PDC (other than Disqualified Stock and other than Equity Interests issued or sold to an employee stock ownership plan, option plan or similar trust to the extent such sale to an employee stock ownership plan, option plan or similar trust is financed by loans from or guaranteed by PDC or any of its Restricted Subsidiaries unless such loans have been repaid with cash on or prior to the date of determination) or from the substantially concurrent contribution of common equity capital to PDC; *provided* that the amount of any such net cash proceeds that are utilized for any such Restricted Payment will be excluded from clause (3)(b) of the preceding paragraph and clause (7) of this paragraph;

(3) the repurchase, redemption, defeasance or other acquisition or retirement for value of Subordinated Debt (including the payment of any required premium and any fees and expenses incurred in connection with such repurchase, redemption, defeasance or other acquisition or retirement) with the net cash proceeds from a substantially concurrent incurrence of Permitted Refinancing Indebtedness;

(4) the defeasance, repurchase, redemption or other acquisition or retirement for value of any Equity Interests of PDC or any Restricted Subsidiary held by any of PDC s or any of its Restricted Subsidiaries current or former directors or employees in connection with the exercise or vesting of any equity compensation (including, without limitation, stock options, restricted stock and phantom stock) in order to satisfy PDC s or such Restricted Subsidiary s tax withholding obligation with respect to such exercise or vesting;

(5) repurchases of Capital Stock deemed to occur upon the exercise of stock options if such Capital Stock represents a portion of the exercise price thereof;

(6) payments to fund the purchase, redemption or other acquisition for value by PDC of fractional Equity Interests arising out of stock dividends, splits or combinations, business combinations or other transactions permitted by the indenture;

(7) as long as no Default has occurred and is continuing or would be caused thereby, the defeasance, repurchase, redemption or other acquisition or retirement for value of any Equity Interests of Parent, PDC or any Restricted Subsidiary held by any of Parent s, PDC s or any of PDC s Restricted Subsidiaries current or former directors or employees; *provided* that the aggregate price paid for all such repurchased, redeemed, acquired or retired Equity Interests may not exceed the sum of (a) $20.0 million *plus* (b) the aggregate amount of cash proceeds received by PDC from the sale of PDC s Equity Interests (other than Disqualified Stock) to any such directors or employees that occurs after the Issue Date; *provided* that the amount of such cash proceeds utilized for any such defeasance, repurchase, redemption or other acquisition or retirement will be excluded from clause (3)(b) of the immediately preceding paragraph and clause (2) of this paragraph *plus* (c) the cash proceeds of key man life insurance policies received by PDC and its Restricted Subsidiaries after the Issue Date;

(8) as long as no Default has occurred and is continuing or would be caused thereby, the declaration and payment of regularly scheduled or accrued dividends to holders of any class or series of Disqualified Stock of PDC or any Restricted Subsidiary issued on or after the Issue Date in accordance with the Fixed Charge Coverage Ratio test described below under the caption Incurrence of Indebtedness and Issuance of Preferred Stock;

(9) the payment of any dividend (or, in the case of any partnership or limited liability company, any similar distribution) by a Restricted Subsidiary to the holders of Equity Interests (other than Disqualified

Stock) of such Restricted Subsidiary; *provided* that such dividend or similar distribution is paid to all holders of such Equity Interests on a pro rata basis based their respective holdings of such Equity Interests;

(10) the purchase or redemption of any Acquired Subordinated Indebtedness of PDC or any of its Restricted Subsidiaries, by application of proceeds from borrowings under the revolving portion of the Senior Credit Agreement; *provided*, in any such case, that PDC is able to incur an additional $1.00 of Indebtedness pursuant to the first paragraph of the covenant described under the caption Incurrence of Indebtedness and Issuance of Preferred Stock after giving effect to such purchase or redemption; *provided further*, that this clause (10) shall not permit the application any proceeds from any other borrowings under any Credit Facility to effect any such purchase or redemption;

(11) repurchases of Subordinated Debt at a purchase price not greater than (a) 101% of the principal amount of such Subordinated Debt and accrued and unpaid interest thereon in the event of a Change of Control or (b) 100% of the principal amount of such Subordinated Debt and accrued and unpaid interest thereon in the event of an Asset Sale in connection with any change of control offer or asset sale offer required by the terms of such Subordinated Debt, but only if:

(i) in the case of a Change of Control, PDC has first complied with and fully satisfied its obligations under the covenant described under Repurchase at the Option of Holders Change of Control; or

(ii) in the case of an Asset Sale, PDC has complied with and fully satisfied its obligations under the covenant described under Repurchase at the Option of Holders Asset Sales;

(12) Permitted Payments to Parent;

(13) payments or distributions to dissenting stockholders pursuant to applicable law in connection with a merger, consolidation or transfer of all or substantially all of the assets of PDC that complies with the provisions described under the caption Merger, Consolidation or Sales of Assets; and

(14) other Restricted Payments in an aggregate amount at any time outstanding not to exceed $20.0 million.

The amount of all Restricted Payments (other than cash) shall be the Fair Market Value on the date of such Restricted Payment of the asset(s) or securities proposed to be paid, transferred or issued by PDC or such Restricted Subsidiary, as the case may be, pursuant to such Restricted Payment.

The Fair Market Value of any cash Restricted Payment shall be its face amount, and the Fair Market Value of any non-cash Restricted Payment exceeding $10.0 million shall be determined conclusively by two senior Officers of PDC acting in good faith whose conclusions with respect thereto shall be set forth in an Officers Certificate delivered to the trustee, *provided*, *however*, that if the Fair Market Value of any non-cash Restricted Payment exceeds $25.0 million, such Fair Market Value shall be determined conclusively by the Board of Directors of PDC and set forth in a board resolution, and a certified copy of such board resolution shall be delivered to the trustee. For purposes of determining compliance with this covenant, in the event that a Restricted Payment meets the criteria of more than one of the exceptions described in (1) through (14) above or is entitled to be made pursuant to the first paragraph of this covenant, PDC shall, in its sole discretion, classify such Restricted Payment, or later classify, reclassify or re-divide all or a portion of such Restricted Payment, in any manner that complies with this covenant.

Incurrence of Indebtedness and Issuance of Preferred Stock

PDC will not, and will not permit any of its Restricted Subsidiaries to directly or indirectly create, incur, issue, assume, guarantee or otherwise become directly or indirectly liable, contingently or otherwise, with respect to (collectively, incur; with *incurrence* having a correlative meaning) any Indebtedness (including Acquired Debt), and PDC will not issue any Disqualified Stock and will not permit any of its Restricted Subsidiaries to issue any shares of preferred stock; *provided*, *however*, that PDC may incur Indebtedness (including Acquired

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Debt) and issue Disqualified Stock, and Restricted Subsidiaries may incur Indebtedness (including Acquired Debt) and issue preferred stock, if (a) the Fixed Charge Coverage Ratio for PDC s most recently ended four full fiscal quarters for which internal financial statements are available immediately preceding the date on which such additional Indebtedness is incurred or such Disqualified Stock or preferred stock is issued, as the case may be, would have been at least 2.0 to 1.0 and (b) to the extent such Indebtedness (including Acquired Debt) constitutes Senior Debt, (i) on any date of determination prior to February 15, 2013, the Senior Net Leverage Ratio is no greater than 4.0 to 1.0 and (ii) on any date of determination on or after February 15, 2013, the Senior Net Leverage Ratio is no greater than 3.50 to 1.0, in each case under clause (a) or (b) above, determined on a pro forma basis (including a pro forma application of the net proceeds therefrom), as if the additional Indebtedness had been incurred or the Disqualified Stock or preferred stock had been issued, as the case may be, at the beginning of such four-quarter period.

Notwithstanding the foregoing, the first paragraph of this covenant will not prohibit the incurrence of any of the following (the items of Indebtedness described below in this paragraph being referred to collectively as *Permitted Debt*):

(1) the incurrence by PDC and any Restricted Subsidiary of Indebtedness and letters of credit under Credit Facilities in an aggregate principal amount at any one time outstanding under this clause (1) (with letters of credit being deemed to have a principal amount equal to the maximum potential liability of PDC and its Restricted Subsidiaries thereunder) not to exceed the greater of (i) $220.0 million and (ii) 25% of Adjusted Consolidated Net Tangible Assets, determined as of the date of the incurrence of such Indebtedness after giving pro forma effect to such incurrence and the application of the proceeds therefrom;

(2) the incurrence by PDC and its Restricted Subsidiaries of Existing Indebtedness;

(3) the incurrence by PDC of Indebtedness represented by the notes to be issued on the Issue Date and the exchange notes to be issued pursuant to the Registration Rights Agreement;

(4) the incurrence by PDC or any of its Restricted Subsidiaries of Indebtedness represented by Capital Lease Obligations, mortgage financings or purchase money obligations, in each case, incurred for the purpose of financing all or any part of the purchase price or cost of design, construction, installation, improvement, deployment, refurbishment or modification of property, plant or equipment or furniture, fixtures and equipment, in each case, used in the business of PDC or any of its Restricted Subsidiaries, in an aggregate principal amount at any time outstanding, including all Permitted Refinancing Indebtedness incurred to renew, refund, refinance, replace, defease or discharge any Indebtedness incurred pursuant to this clause (4), not to exceed the greater of (a) $25.0 million and (b) 3.0% of Adjusted Consolidated Net Tangible Assets;

(5) the incurrence by PDC or any of its Restricted Subsidiaries of Permitted Refinancing Indebtedness in exchange for, or the net proceeds of which are used to renew, refund, refinance, replace, defease or discharge any Indebtedness (other than intercompany Indebtedness) or Disqualified Stock of PDC, or Indebtedness (other than intercompany Indebtedness) or preferred stock of a Restricted Subsidiary, in each case that was permitted by the indenture to be incurred or issued under the first paragraph of this covenant or clauses (2), (3), (4), (10), (16) or (17) of this paragraph or this clause (5);

(6) the incurrence by PDC or any of its Restricted Subsidiaries of intercompany Indebtedness between or among PDC and any of its Restricted Subsidiaries; *provided*, *however*, that (a) any subsequent issuance or transfer of Equity Interests that results in any such Indebtedness being held by a Person other than PDC or a Restricted Subsidiary and (b) any sale or other transfer of any such Indebtedness to a Person that is not either PDC or a Restricted Subsidiary will be deemed, in each case, to constitute an incurrence of such Indebtedness by PDC or such Restricted Subsidiary, as the case may be, that was not permitted by this clause (6);

(7) the issuance by any of PDC s Restricted Subsidiaries to PDC or to any of its Restricted Subsidiaries of shares of preferred stock; *provided*, *however*, that:

(a) any subsequent issuance or transfer of Equity Interests that results in any such preferred stock being held by a Person other than PDC or a Restricted Subsidiary; and

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(b) any sale or other transfer of any such preferred stock to a Person that is not either PDC or a Restricted Subsidiary,

will be deemed, in each case, to constitute an issuance of such preferred stock by such Restricted Subsidiary that was not permitted by this clause (7);

(8) the incurrence of obligations of PDC or a Restricted Subsidiary pursuant to Interest Rate and Currency Hedges, in each case entered into in the ordinary course of business for the purpose of limiting risks that arise in the ordinary course of business of PDC and its Restricted Subsidiaries;

(9) the guarantee by PDC or any of the Subsidiary Guarantors of Indebtedness of PDC or a Restricted Subsidiary that was permitted to be incurred by another provision of this covenant; *provided* that if the Indebtedness being guaranteed is subordinated to or *pari passu* with the notes, then the guarantee shall be subordinated or *pari passu*, as applicable, to the same extent as the Indebtedness guaranteed;

(10) Permitted Acquisition Indebtedness;

(11) the incurrence by PDC or any Restricted Subsidiary of Indebtedness arising from the honoring by a bank or other financial institution of a check, draft or similar instrument inadvertently drawn against insufficient funds, so long as such Indebtedness is covered within five Business Days;

(12) Indebtedness consisting of the financing of insurance premiums in customary amounts consistent with the operations and business of PDC and its Restricted Subsidiaries;

(13) the incurrence by PDC or any Restricted Subsidiary of Indebtedness arising from agreements of PDC or any of its Restricted Subsidiaries providing for indemnification, adjustment of purchase price or similar obligations, in each case, incurred or assumed in connection with the disposition of any business, assets or Capital Stock of a Subsidiary, *provided* that the maximum aggregate liability in respect of all such Indebtedness shall at no time exceed the gross proceeds actually received by PDC and its Restricted Subsidiaries in connection with such disposition;

(14) the incurrence by PDC or any Restricted Subsidiary of Indebtedness constituting reimbursement obligations with respect to letters of credit issued in the ordinary course of business; *provided* that, upon the drawing of such letters of credit or the incurrence of such Indebtedness, such obligations are reimbursed within one year following such drawing or incurrence;

(15) the incurrence by PDC or any of its Restricted Subsidiaries of Indebtedness in the form of Guarantees of Indebtedness of joint ventures; *provided* that the aggregate principal amount of the Obligations incurred pursuant to such Guarantees shall not exceed the greater of $25.0 million and 3.0% of Adjusted Consolidated Net Tangible Assets, determined as of the date of each incurrence of such Guarantee after giving pro forma effect to the application of proceeds of the Indebtedness being guaranteed;

(16) the incurrence by Foreign Subsidiaries of Indebtedness in an aggregate amount at any time outstanding pursuant to this clause (16), including all Permitted Refinancing Indebtedness incurred to renew, refund, refinance, replace, defease or discharge any Indebtedness incurred pursuant to this clause (16), not to exceed 15% of such Foreign Subsidiaries Adjusted Consolidated Net Tangible Assets, determined as of the date of each incurrence, in the applicable foreign currency; and

(17) the incurrence by PDC or any of its Restricted Subsidiaries of Indebtedness in an aggregate principal amount (or accreted value, as applicable) that, when taken together with all other Indebtedness of PDC and its Restricted Subsidiaries outstanding on the date of such incurrence (other than Indebtedness permitted by clauses (1) through (16) above or the first paragraph of this covenant) and any Permitted Refinancing Indebtedness incurred to renew, refund, refinance, replace, defease or discharge any Indebtedness incurred pursuant to this clause (17) does not exceed the greater of (a) 2.5% of Adjusted Consolidated Net Tangible Assets determined as of the date of incurrence of such Indebtedness and (b) $20.0 million.

PDC will not incur, and will not permit any Subsidiary Guarantor to incur, any Indebtedness (including Permitted Debt) that is contractually subordinated in right of payment to any other Indebtedness of PDC or such Subsidiary Guarantor unless such Indebtedness is also contractually subordinated in right of payment to the notes and the applicable Subsidiary Guarantee, on substantially identical terms; *provided*, *however*, that no Indebtedness will be deemed to be contractually subordinated in right of payment to any other Indebtedness of PDC solely by virtue of being unsecured or by virtue of being secured on a first or junior Lien basis.

For purposes of determining compliance with this Incurrence of Indebtedness and Issuance of Preferred Stock covenant, in the event that an item of proposed Indebtedness meets the criteria of more than one of the categories of Permitted Debt described in clauses (1) through (17) of the second paragraph of this covenant, or is entitled to be incurred pursuant to the first paragraph of this covenant, PDC will be permitted to divide and classify such item of Indebtedness on the date of its incurrence, or later divide and reclassify all or a portion of such item of Indebtedness, in any manner that complies with this covenant. The accrual of interest, the accretion or amortization of original issue discount, the payment of interest on any Indebtedness in the form of additional Indebtedness with the same terms, the reclassification of preferred stock as Indebtedness due to a change in accounting principles, and the payment of dividends on Disqualified Stock in the form of additional shares of the same class of Disqualified Stock will be deemed not to be an incurrence of Indebtedness or an issuance of Disqualified Stock for purposes of this covenant; *provided*, in each such case, that the amount of any such accrual, accretion or payment is included in Fixed Charges of PDC as accrued.

For purposes of determining compliance with any U.S. dollar-denominated restriction on the incurrence of Indebtedness and issuance of preferred stock, the U.S. dollar-equivalent principal amount of Indebtedness denominated in a foreign currency shall be calculated based on the relevant currency exchange rate in effect on the date such Indebtedness was incurred, in the case of term Indebtedness, or first committed, in the case of revolving credit Indebtedness; *provided* that if such Indebtedness is incurred to refinance other Indebtedness denominated in a foreign currency, and such refinancing would cause the applicable U.S. dollar-denominated restriction to be exceeded if calculated at the relevant currency exchange rate in effect on the date of such refinancing, such U.S. dollar-denominated restriction shall be deemed not to have been exceeded so long as the principal amount of such refinancing Indebtedness does not exceed the principal amount of such Indebtedness being refinanced. Notwithstanding any other provision of this covenant, the maximum amount of Indebtedness that PDC or any Restricted Subsidiary may incur pursuant to this covenant shall not be deemed to be exceeded solely as a result of fluctuations in the exchange rate of currencies. The principal amount of any Permitted Refinancing Indebtedness incurred to refinance other Indebtedness, if incurred in a different currency from the Indebtedness being refinanced, shall be calculated based on the currency exchange rate applicable to the currencies in which such Permitted Refinancing Indebtedness is denominated that is in effect on the date of such refinancing.

Limitation on Liens

PDC will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create, incur or permit to exist any Lien (other than Permitted Liens) upon any Principal Property or any shares of stock or Indebtedness of any Restricted Subsidiary that owns or leases any Principal Property (whether such Principal Property, shares of stock or Indebtedness are now owned or hereafter acquired), securing any Subordinated Debt or other Indebtedness, unless:

(1) in the case of Liens securing Subordinated Debt of PDC or a Subsidiary Guarantor, the notes or Subsidiary Guarantee, as applicable, are secured by a Lien on such Principal Property or such shares of stock or Indebtedness on a senior basis to the Subordinated Debt so secured with the same priority as the notes or such Subsidiary Guarantee, as applicable, has to such Subordinated Debt until such time as such Subordinated Debt is no longer so secured by a Lien; and

(2) in the case of Liens securing other Indebtedness of PDC or a Subsidiary Guarantor, the notes or Subsidiary Guarantees, as applicable, are secured by a Lien on such Principal Property or such shares of stock or Indebtedness on an equal and ratable basis with the other Indebtedness so secured until such time as such other Indebtedness is no longer so secured by a Lien.

Dividend and Other Payment Restrictions Affecting Restricted Subsidiaries

PDC will not, and will not permit any of its Restricted Subsidiaries to, directly or indirectly, create or permit to exist or become effective any consensual encumbrance or restriction on the ability of any Restricted Subsidiary to:

(a) pay dividends or make any other distributions on its Capital Stock to PDC or any of its Restricted Subsidiaries, or with respect to any other interest or participation in, or measured by, its profits, or pay any Indebtedness owed to PDC or any of its Restricted Subsidiaries;

(b) make loans or advances to PDC or any of its Restricted Subsidiaries; or

(c) sell, lease or transfer any of its properties or assets to PDC or any of its Restricted Subsidiaries.

However, the preceding restrictions will not apply to encumbrances or restrictions existing under, by reason of or with respect to:

(1) the Senior Credit Agreement, any Existing Indebtedness, Capital Stock or any other agreements or instruments, in each case in effect on the Issue Date and any amendments, restatements, modifications, renewals, extensions, supplements, increases, refundings, replacements or refinancings thereof; *provided* that the encumbrances and restrictions in any such amendments, restatements, modifications, renewals, extensions, supplements, increases, refundings, replacements or refinancings are, in the reasonable good faith judgment of the Chief Executive Officer and the Chief Financial Officer of PDC, no more restrictive, taken as a whole, than those contained in the applicable agreements or instruments as in effect on the Issue Date;

(2) the indenture, the notes and the Subsidiary Guarantees;

(3) applicable law, rule, regulation, order, approval, permit or similar restriction;

(4) any instrument governing Indebtedness or Capital Stock of a Person acquired by PDC or any of its Restricted Subsidiaries as in effect at the time of such acquisition (except to the extent such Indebtedness or Capital Stock was incurred in connection with or in contemplation of such acquisition), which encumbrance or restriction is not applicable to any Person, or the properties or assets of any Person, other than the Person, or the property or assets of the Person, so acquired and any amendments, restatements, modifications, renewals, extensions, supplements, increases, refundings, replacements or refinancings thereof, *provided*, that the encumbrances and restrictions in any such amendments, restatements, modifications, renewals, extensions, supplements, increases, refundings, replacements or refinancings are, in the reasonable good faith judgment of the Chief Executive Officer and Chief Financial Officer of PDC, no more restrictive, taken as a whole, than those in effect on the date of the acquisition; *provided*, *further*, that, in the case of Indebtedness, such Indebtedness was permitted by the terms of the indenture to be incurred;

(5) customary non-assignment provisions in contracts, leases and licenses (including, without limitation, licenses of intellectual property) entered into in the ordinary course of business;

(6) any agreement for the sale or other disposition of the Equity Interests in, or all or substantially all of the assets of, a Restricted Subsidiary, that restricts distributions by the applicable Restricted Subsidiary pending the sale or other disposition;

(7) Permitted Refinancing Indebtedness; *provided* that the restrictions contained in the agreements governing such Permitted Refinancing Indebtedness are not materially more restrictive, taken as a whole, than those contained in the agreements governing the Indebtedness being refinanced;

(8) Liens permitted to be incurred under the provisions of the covenant described above under the caption Limitation on Liens that limit the right of the debtor to dispose of the assets subject to such Liens;

(9) the issuance of preferred stock by a Restricted Subsidiary or the payment of dividends thereon in accordance with the terms thereof; *provided* that issuance of such preferred stock is permitted pursuant to the covenant described under the caption Incurrence of Indebtedness and Issuance of Preferred Stock

and the terms of such preferred stock do not expressly restrict the ability of a Restricted Subsidiary to pay dividends or make any other distributions on its Capital Stock (other than requirements to pay dividends or liquidation preferences on such preferred stock prior to paying any dividends or making any other distributions on such other Capital Stock);

(10) other Indebtedness of PDC or any of its Restricted Subsidiaries permitted to be incurred pursuant to an agreement entered into subsequent to the Issue Date in accordance with the covenant described under the caption Incurrence of Indebtedness and Issuance of Preferred Stock; *provided* that the provisions relating to such encumbrance or restriction contained in such Indebtedness are not materially less favorable to PDC and its Restricted Subsidiaries, taken as a whole, as determined by PDC in good faith, than the provisions contained in the Senior Credit Agreement as in effect on the Issue Date;

(11) Indebtedness incurred or Capital Stock issued by any Restricted Subsidiary, provided that the restrictions contained in the agreements or instruments governing such Indebtedness or Capital Stock (a) either (i) apply only in the event of a payment default or a default with respect to a financial covenant in such agreement or instrument or (ii) will not materially affect PDC s ability to pay all principal, interest and premium and Liquidated Damages, if any, on the notes, in the reasonable good faith judgment of the Chief Executive Officer and Chief Financial Officer of PDC; and (b) are not materially more disadvantageous to the holders of the notes than is customary in comparable financings (in the reasonable good faith judgment of the Chief Executive Officer and Chief Financial Officer of PDC);

(12) customary provisions restricting subletting or assignment of any lease governing a leasehold interest;

(13) Hedging Obligations permitted from time to time under the indenture;

(14) restrictions on cash or other deposits or net worth imposed by customers under contracts entered into in the ordinary course of business; and

(15) with respect only to encumbrances or restrictions of the type referred to in clause (c) of the immediately preceding paragraph:

(a) customary nonassignment provisions (including provisions forbidding subletting) in leases governing leasehold interests or Farm-In Agreements or Farm-Out Agreements relating to leasehold interests in Oil and Gas Properties to the extent such provisions restrict the transfer of the lease, the property leased thereunder or the other interests therein;

(b) provisions limiting the disposition or distribution of assets or property in, or transfer of Capital Stock of, joint venture agreements, asset sale agreements, sale-leaseback agreements, stock sale agreements and other similar agreements entered into (i) in the ordinary course of business, consistent with past practice or (ii) with the approval of PDC s Board of Directors, which limitations are applicable only to the assets, property or Capital Stock that are the subject of such agreements; and

(c) Capital Lease Obligations, security agreements, mortgages, purchase money agreements or similar instruments to the extent such encumbrance or restriction restricts the transfer of the property (including Capital Stock) subject to such Capital Lease Obligations, security agreements, mortgages, purchase money agreements or similar instruments.

Transactions with Affiliates

PDC will not, and will not permit any of its Restricted Subsidiaries to, make any payment to, or sell, lease, transfer or otherwise dispose of any of its properties or assets to, or purchase any property or assets from, or enter into or make or amend any transaction, contract, agreement, understanding, loan, advance or Guarantee with, or for the benefit of, any Affiliate of PDC (each, an *Affiliate Transaction*), unless:

(1) the Affiliate Transaction is on terms that are no less favorable to PDC or the relevant Restricted Subsidiary than those that would have been obtained in a comparable transaction by PDC or such Restricted Subsidiary with a Person that is not an Affiliate of PDC; and

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(2) PDC delivers to the trustee:

(a) with respect to any Affiliate Transaction or series of related Affiliate Transactions involving aggregate consideration in excess of $20.0 million, a resolution of the Board of Directors of PDC set forth in an Officers Certificate certifying that such Affiliate Transaction or series of related Affiliate Transactions complies with this covenant and that such Affiliate Transaction or series of related Affiliate Transactions has been approved by a majority of the disinterested members of the Board of Directors of PDC; and

(b) with respect to any Affiliate Transaction or series of related Affiliate Transactions involving aggregate consideration in excess of $40.0 million, an opinion as to the fairness to PDC or such Restricted Subsidiary of such Affiliate Transaction or series of related Affiliate Transactions from a financial point of view issued by an accounting, appraisal or investment banking firm of national standing.

The following items will not be deemed to be Affiliate Transactions and, therefore, will not be subject to the provisions of the prior paragraph:

(1) any employment, consulting or similar agreement or arrangement, stock option or stock ownership plan, employee benefit plan, officer or director indemnification agreement, restricted stock agreement, severance agreement or other compensation plan or arrangement entered into by PDC or any of its Restricted Subsidiaries in the ordinary course of business and payments, awards, grants or issuances of securities pursuant thereto;

(2) transactions between or among PDC and/or its Restricted Subsidiaries;

(3) transactions with a Person that is an Affiliate of PDC solely because PDC owns, directly or through a Subsidiary, an Equity Interest in, or controls, such Person;

(4) reasonable fees and expenses and compensation paid to, and indemnity or insurance provided on behalf of, officers, directors or employees of PDC or any of its Restricted Subsidiaries;

(5) any issuance of Equity Interests (other than Disqualified Stock) of PDC to, or receipt of a capital contribution from, Affiliates of PDC;

(6) Restricted Payments that do not violate the provisions of the indenture described above under the caption Restricted Payments or any Permitted Investments;

(7) loans or advances to employees in the ordinary course of business or consistent with past practice;

(8) advances to or reimbursements of employees for moving, entertainment and travel expenses, drawing accounts and similar expenditures in the ordinary course of business;

(9) the performance of obligations of PDC or any of its Restricted Subsidiaries under the terms of any written agreement to which PDC or any of its Restricted Subsidiaries was a party on the Issue Date, as these agreements may be amended, modified or supplemented from time to time; *provided*, *however*, that any future amendment, modification or supplement entered into after the Issue Date will be permitted to the extent that its terms do not materially and adversely affect the rights of any holders of the notes (as determined in good faith by the Board of Directors of PDC) as compared to the terms of the agreements in effect on the Issue Date;

(10)(a) guarantees of performance by PDC and its Restricted Subsidiaries of Unrestricted Subsidiaries in the ordinary course of business, except for guarantees of Indebtedness in respect of borrowed money, and (b) pledges of Equity Interests of Unrestricted Subsidiaries for the benefit of lenders of Unrestricted Subsidiaries; and

(11) transactions between PDC or any Restricted Subsidiary and any Person, a director of which is also a director of PDC or any direct or indirect parent company of PDC and such director is the sole cause for such Person to be deemed an Affiliate of PDC or any Restricted Subsidiary; *provided*, *however*, that such

director abstains from voting as a director of PDC or such direct or indirect parent company of PDC, as the case may be, on any matter involving such other Person.

Designation of Restricted and Unrestricted Subsidiaries

The Board of Directors of PDC may designate any Restricted Subsidiary to be an Unrestricted Subsidiary if that designation would not cause a Default. If a Restricted Subsidiary is designated as an Unrestricted Subsidiary, the aggregate Fair Market Value of all outstanding Investments owned by PDC and its Restricted Subsidiaries in the Subsidiary designated as an Unrestricted Subsidiary will be deemed to be an Investment made as of the time of the designation and will reduce the amount available for Restricted Payments under the covenant described above under the caption Restricted Payments or under one or more clauses of the definition of Permitted Investments, as determined by PDC. That designation will only be permitted if the Investment would be permitted at that time and if the applicable Restricted Subsidiary otherwise meets the definition of an Unrestricted Subsidiary.

Any designation of a Subsidiary of PDC as an Unrestricted Subsidiary will be evidenced to the trustee by filing with the trustee a certified copy of a resolution of the Board of Directors of PDC giving effect to such designation and an Officers Certificate certifying that such designation complied with the preceding conditions and was permitted by the covenant described above under the caption Restricted Payments. If, at any time, any Unrestricted Subsidiary would fail to meet the requirements of the definition of Unrestricted Subsidiary set forth below under Definitions, it will thereafter cease to be an Unrestricted Subsidiary for purposes of the indenture and any Indebtedness of such Subsidiary will be deemed to be incurred by a Restricted Subsidiary as of such date and, if such Indebtedness is not permitted to be incurred as of such date under the covenant described under the caption Incurrence of Indebtedness and Issuance of Preferred Stock, PDC will be in Default of such covenant. The Board of Directors of PDC may at any time designate any Unrestricted Subsidiary to be a Restricted Subsidiary; *provided* that such designation will be deemed to be an incurrence of Indebtedness by a Restricted Subsidiary of any outstanding Indebtedness of such Unrestricted Subsidiary, and such designation will only be permitted if (1) such Indebtedness is permitted under the covenant described under the caption Incurrence of Indebtedness and Issuance of Preferred Stock, calculated on a pro forma basis as if such designation had occurred at the beginning of the four-quarter reference period; and (2) no Default or Event of Default would be in existence following such designation.

Reports

Regardless of whether required by the rules and regulations of the SEC, so long as any notes are outstanding, PDC will file with the SEC for public availability, within the time periods specified in the SEC s rules and regulations (unless the SEC will not accept such a filing, in which case PDC will furnish to the holders of notes or cause the trustee to furnish to the holders of notes, within the time periods specified in the SEC s rules and regulations, and will post on PDC s website):

(1) all quarterly and annual reports that would be required to be filed with the SEC on Forms 10-Q and 10-K if PDC were required to file such reports; and

(2) all current reports that would be required to be filed with the SEC on Form 8-K if PDC were required to file such reports.

All such reports will be prepared in all material respects in accordance with all of the rules and regulations applicable to such reports. Each annual report on Form 10-K will include a report on PDC s consolidated financial statements by PDC s certified independent accountants.

If, at any time, PDC is no longer subject to the periodic reporting requirements of the Exchange Act for any reason, PDC will nevertheless continue filing the reports specified in the preceding paragraphs of this covenant with the SEC within the time periods specified above unless the SEC will not accept such a filing. PDC will not

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take any action for the purpose of causing the SEC not to accept any such filings. If, notwithstanding the foregoing, the SEC will not accept PDC s filings for any reason, PDC will post the reports referred to in the preceding paragraphs on its website within the time periods that would apply if PDC were required to file those reports with the SEC.

If PDC has designated any of its Subsidiaries as Unrestricted Subsidiaries, then, the quarterly and annual financial information required by the preceding paragraphs will include a reasonably detailed presentation, either on the face of the financial statements or in the footnotes thereto, and in Management s Discussion and Analysis of Financial Condition and Results of Operations, of the financial condition and results of operations of PDC and its Restricted Subsidiaries separate from the financial condition and results of operations of the Unrestricted Subsidiaries.

In addition, PDC agrees that, for so long as any notes remain outstanding, if at any time it is not required to file with the SEC the reports required by the preceding paragraphs, it will furnish to the holders of notes and to securities analysts and prospective investors, upon their request, the information required to be delivered pursuant to Rule 144A(d)(4) under the Securities Act.

Subsidiary Guarantees

If, on any date after the Issue Date, any Domestic Restricted Subsidiary that is not already a Subsidiary Guarantor both:

(a) Guarantees (or otherwise becomes liable for) Obligations under the Senior Credit Agreement; and

(b) constitutes a Material Subsidiary,

then such Domestic Restricted Subsidiary will unconditionally Guarantee the notes and concurrently become a Subsidiary Guarantor in accordance with the procedures specified in the indenture.

The Subsidiary Guarantee of a Subsidiary Guarantor will be released at such time as such Subsidiary Guarantor ceases to either (i) Guarantee (or otherwise be liable for) Obligations under the Senior Credit Agreement or (ii) constitute a Material Subsidiary.

Merger, Consolidation or Sale of Substantially All Assets

PDC will not (1) consolidate or merge with or into another Person (regardless of whether PDC is the surviving corporation), convert into another form of entity or continue in another jurisdiction; or (2) directly or indirectly, sell, assign, transfer, lease, convey or otherwise dispose of all or substantially all of its properties or assets, in one or more related transactions, to another Person, unless:

(1) either: (a) PDC is the surviving corporation; or (b) the Person formed by or surviving any such consolidation or merger or resulting from such conversion (if other than PDC) or to which such sale, assignment, transfer, conveyance or other disposition has been made is a corporation, limited liability company or limited partnership organized or existing under the laws of the United States, any state of the United States or the District of Columbia;

(2) the Person formed by or surviving any such conversion, consolidation or merger (if other than PDC) or the Person to which such sale, assignment, transfer, conveyance or other disposition has been made assumes all the obligations of PDC under the notes and the indenture (and the Registration Rights Agreement, if any obligations thereunder remain unsatisfied) pursuant to agreements reasonably satisfactory to the trustee; *provided* that, unless such Person is a corporation, a corporate co-issuer of the notes will be added to the indenture by agreements reasonably satisfactory to the trustee;

(3) immediately after such transaction or transactions, no Default or Event of Default exists; and

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(4) PDC or the Person formed by or surviving any such consolidation or merger (if other than PDC), or to which such sale, assignment, transfer, conveyance or other disposition has been made:

(a) would, on the date of such transaction after giving pro forma effect thereto and any related financing transactions as if the same had occurred at the beginning of the applicable four-quarter period, be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test set forth in the first paragraph of the covenant described above under the caption Incurrence of Indebtedness and Issuance of Preferred Stock; or

(b) would, on the date of such transaction after giving pro forma effect thereto and any related financing transactions as if the same had occurred at the beginning of the applicable four-quarter period, have a Fixed Charge Coverage Ratio that is not less than the Fixed Charged Coverage Ratio of PDC and its Restricted Subsidiaries immediately prior to such transaction.

For purposes of this covenant, the sale, lease, conveyance, assignment, transfer, or other disposition of all or substantially all of the properties and assets of one or more Subsidiaries of PDC, which properties and assets, if held by PDC instead of such Subsidiaries, would constitute all or substantially all of the properties and assets of PDC on a consolidated basis, shall be deemed to be the transfer of all or substantially all of the assets of PDC.

The surviving entity will succeed to, and be substituted for, and may exercise every right and power of, PDC under the indenture; *provided*, *however*, that PDC will not be released from the obligation to pay the principal of and interest on the notes except in the case of a sale of all of PDC s assets in a transaction that is subject to, and that complies with the provisions of, this covenant.

Notwithstanding the restrictions described in the foregoing clause (4), any Restricted Subsidiary may consolidate with, merge into or transfer all or part of its properties and assets to PDC, PDC may merge into a Restricted Subsidiary for the purpose of reincorporating PDC in another jurisdiction, and any Restricted Subsidiary may consolidate with, merge into or transfer all or part of its properties and assets to another Restricted Subsidiary.

Although there is a limited body of case law interpreting the phrase substantially all, there is no precise established definition of the phrase under applicable law. Accordingly, in certain circumstances there may be a degree of uncertainty as to whether a particular transaction would involve all or substantially all of the property or assets of a Person.

Events of Default

Under the indenture, each of the following constitutes an *Event of Default* with respect to the notes:

(1) default for 30 days in the payment when due of interest on, or Liquidated Damages, if any, with respect to, the notes;

(2) default in the payment when due of the principal of, or premium, if any, on the notes;

(3) failure by PDC to comply with its obligations under Covenants Merger, Consolidation or Sale of Substantially All Assets or to consummate a purchase of notes when required pursuant to the covenants described under the caption Repurchase at the Option of Holders;

(4) failure by PDC or any of its Restricted Subsidiaries for 30 days after written notice from the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding notes to comply with the provisions described under the captions Covenants Restricted Payments or Covenants Incurrence of Indebtedness and Issuance of Preferred Stock or to comply with the provisions described under the captions Repurchase at the Option of Holders to the extent not described in clause (3) above;

(5)(a) except as addressed in subclause (b) of this clause (5), failure by PDC or any of its Restricted Subsidiaries for 60 days after written notice from the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding notes to comply with any of the other agreements in the indenture or the notes or (b) failure by PDC for 360 days after notice from the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding notes to comply with the covenant described under the caption Covenants Reports;

(6) default under any mortgage, indenture or instrument under which there may be issued or by which there may be secured or evidenced any Indebtedness for money borrowed by PDC or any of its Restricted Subsidiaries (or the payment of which is guaranteed by PDC or any of its Restricted Subsidiaries), other than Indebtedness owed to PDC or any of its Restricted Subsidiaries, whether such Indebtedness or Guarantee now exists, or is created after the Issue Date, which default:

(a) is caused by a failure to pay principal of, or interest or premium, if any, on such Indebtedness prior to the expiration of the grace period provided in such Indebtedness (*Payment Default*); or

(b) results in the acceleration of such Indebtedness prior to its maturity;

and, in each case, the principal amount of any such Indebtedness, together with the principal amount of any other such Indebtedness under which there has been a Payment Default or the maturity of which has been so accelerated, aggregates $20.0 million or more;

(7) failure by PDC or any Significant Subsidiary or group of PDC s Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for PDC and its Restricted Subsidiaries), would constitute a Significant Subsidiary to pay final judgments aggregating in excess of $20.0 million (net of any amounts that a reputable and creditworthy insurance company has acknowledged liability for in writing), which judgments are not paid, discharged or stayed for a period of 60 days;

(8) except as permitted by the indenture, any Subsidiary Guarantee is held in a judicial proceeding to be unenforceable or invalid or ceases for any reason to be in full force and effect, or any Subsidiary Guarantor, or any Person acting on behalf of any Subsidiary Guarantor, denies or disaffirms its obligations under its Subsidiary Guarantee; or

(9) certain events of bankruptcy, insolvency or reorganization with respect to PDC or a Significant Subsidiary or group of Restricted Subsidiaries that, taken together (as of the latest audited consolidated financial statements for PDC and its Restricted Subsidiaries), would constitute a Significant Subsidiary.

The indenture provides that in the case of an Event of Default arising from certain events of bankruptcy or insolvency, with respect to PDC, any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all then outstanding notes will become due and payable immediately without further action or notice. If any other Event of Default occurs and is continuing, the trustee or the holders of at least 25% in aggregate principal amount of the then outstanding notes may declare all of the notes to be due and payable immediately by notice in writing to PDC and, in case of a notice by holders, also to the trustee specifying the respective Event of Default and that it is a notice of acceleration.

Upon any failure by PDC for 60 days to comply with the covenant described under the caption Covenants Reports, the interest rate on the notes will increase by 0.50% per annum and remain at such increased rate thereafter, but only for as long as there is a continuing Default under such covenant, and upon resumption of compliance by PDC with such covenant, the interest rate will be reset as if the interest rate had never been increased pursuant to this provision.

Subject to certain limitations, holders of a majority in aggregate principal amount of the then outstanding notes may direct the trustee in its exercise of any trust or power with respect to the notes. The trustee may withhold from holders of the notes notice of any continuing Default or Event of Default if it determines that withholding notice is in their interest, except a Default or Event of Default relating to the payment of principal, interest or premium or Liquidated Damages, if any.

Subject to the provisions of the indenture relating to the duties of the trustee, in case an Event of Default occurs and is continuing, the trustee will be under no obligation to exercise any of the rights or powers under the indenture at the request or direction of any holders of notes unless such holders have offered to the trustee reasonable indemnity or security against any loss, liability or expense. Except to enforce the right to receive payment of principal, premium, if any, or interest or Liquidated Damages, if any, when due, no holder of a note may pursue any remedy with respect to the indenture or the notes unless:

(a) such holder has previously given the trustee notice of a continuing Event of Default;

(b) holders of at least 25% in aggregate principal amount of the then outstanding notes have made a written request to the trustee to pursue the remedy;

(c) such holders have offered the trustee reasonable security or indemnity against any loss, liability or expense;

(d) the trustee has not complied with such request within 60 days after the receipt of the request and the offer of security or indemnity; and

(e) holders of a majority in aggregate principal amount of the then outstanding notes have not given the trustee a direction that is inconsistent with such request within such 60-day period.

The holders of a majority in aggregate principal amount of the then outstanding notes by notice to the trustee may, on behalf of the holders of all of the notes, rescind an acceleration or waive any existing Default or Event of Default and its consequences under the indenture except a continuing Default or Event of Default in the payment of interest or premium or Liquidated Damages, if any, on, or the principal of, the notes.

Notwithstanding the foregoing, if an Event of Default specified in clause (6) above shall have occurred and be continuing, such Event of Default and any consequential acceleration shall be automatically rescinded if (i) the Indebtedness that is the subject of such Event of Default has been repaid or (ii) if the default relating to such Indebtedness is waived or cured and if such Indebtedness has been accelerated, then the holders thereof have rescinded their declaration of acceleration in respect of such Indebtedness.

PDC is required to deliver to the trustee annually a statement regarding compliance with the indenture. Upon becoming aware of any Default or Event of Default, PDC is required within five Business Days to deliver to the trustee a statement specifying such Default or Event of Default.

No Personal Liability of Directors, Officers, Employees and Stockholders

No director, officer, employee, incorporator, stockholder, member, manager or partner of PDC or any Subsidiary Guarantor, as such, will have any liability for any obligations of PDC or the Subsidiary Guarantors under the notes, the indenture, the Subsidiary Guarantees or for any claim based on, in respect of, or by reason of, such obligations or their creation. Each holder of notes by accepting a note waives and releases all such liability. The waiver and release are part of the consideration for issuance of the notes. The waiver may not be effective to waive liabilities under the federal securities laws.

Legal Defeasance and Covenant Defeasance

PDC may, at any time, at the option of its Board of Directors evidenced by a resolution set forth in an Officers Certificate, elect to have all of its obligations discharged with respect to the outstanding notes and all obligations of the Subsidiary Guarantors discharged with respect to their Subsidiary Guarantees (*Legal Defeasance*) except for:

(1) the rights of holders of outstanding notes to receive payments in respect of the principal of, or interest or premium and Liquidated Damages, if any, on such notes when such payments are due from the trust referred to below;

(2) PDC s obligations with respect to the notes concerning issuing temporary notes, registration of notes, mutilated, destroyed, lost or stolen notes and the maintenance of an office or agency for payment and money for security payments held in trust;

(3) the rights, powers, trusts, duties and immunities of the trustee, and PDC s and the Subsidiary Guarantors obligations in connection therewith; and

(4) the Legal Defeasance and Covenant Defeasance provisions of the indenture.

In addition, PDC may, at its option and at any time, elect to have the obligations of PDC and the Subsidiary Guarantors released with respect to the provisions of the indenture described above under Repurchase at the Option of Holders and under Covenants (other than the covenant described under Covenants Merger, Consolidation or Sale of Assets, except to the extent described below) and the limitation imposed by clause (4) under Covenants Merger, Consolidation or Sale of Assets (such release and termination being referred to as *Covenant Defeasance*), and thereafter any omission to comply with such obligations or provisions will not constitute a Default or Event of Default with respect to the notes. In the event Covenant Defeasance occurs in accordance with the indenture, the Events of Default described under clauses (3) through (7) under the caption Events of Default and Remedies and the Event of Default described under clause (9) under the caption Events of Default and Remedies (but only with respect to Subsidiaries of PDC), in each case, will no longer constitute an Event of Default with respect to the notes.

In order to exercise either Legal Defeasance or Covenant Defeasance:

(1) PDC must irrevocably deposit with the trustee, in trust, for the benefit of the holders of the notes, cash in U.S. dollars, non-callable Government Securities, or a combination of cash in U.S. dollars and non-callable Government Securities, in amounts as will be sufficient, in the opinion of a nationally recognized investment bank, appraisal firm or firm of independent public accountants to pay the principal of, or interest and premium and Liquidated Damages, if any, on the outstanding notes on the stated date for payment thereof or on the applicable redemption date, as the case may be, and PDC must specify whether the notes are being defeased to such stated date for payment or to a particular redemption date;

(2) in the case of Legal Defeasance, PDC must deliver to the trustee an opinion of counsel reasonably acceptable to the trustee confirming that (a) PDC has received from, or there has been published by, the Internal Revenue Service a ruling or (b) since the Issue Date, there has been a change in the applicable U.S. federal income tax law, in either case to the effect that, and based thereon such opinion of counsel will confirm that, the holders of the outstanding notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Legal Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Legal Defeasance had not occurred;

(3) in the case of Covenant Defeasance, PDC has delivered to the trustee an opinion of counsel reasonably acceptable to the trustee confirming that the holders of the outstanding notes will not recognize income, gain or loss for U.S. federal income tax purposes as a result of such Covenant Defeasance and will be subject to U.S. federal income tax on the same amounts, in the same manner and at the same times as would have been the case if such Covenant Defeasance had not occurred;

(4) no Default or Event of Default has occurred and is continuing on the date of such deposit (other than a Default or Event of Default resulting from the borrowing of funds to be applied to such deposit);

(5) the deposit will not result in a breach or violation of, or constitute a default under, any other instrument to which PDC or any Subsidiary Guarantor is a party or by which PDC or any Subsidiary Guarantor is bound;

(6) such Legal Defeasance or Covenant Defeasance will not result in a breach or violation of, or constitute a default under, any material agreement or instrument (other than the indenture) to which PDC or any of its Subsidiaries is a party or by which PDC or any of its Subsidiaries is bound;

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(7) PDC must deliver to the trustee an Officers Certificate stating that the deposit was not made by PDC with the intent of preferring the holders of notes over the other creditors of PDC with the intent of defeating, hindering, delaying or defrauding any creditors of PDC or others;

(8) PDC must deliver to the trustee an Officers Certificate, stating that all conditions precedent set forth in clauses (1) through (7) of this paragraph have been complied with; and

(9) PDC must deliver to the trustee an opinion of counsel, stating that all conditions precedent set forth in clauses (2), (3) and (5) of this paragraph have been complied with.

Amendment, Supplement and Waiver

Except as provided in the next two succeeding paragraphs, the indenture, the debt securities issued thereunder (including the notes) or any Guarantee thereof may be amended or supplemented with the consent of the holders of a majority in aggregate principal amount of the then-outstanding debt securities of each series affected by such amendment or supplemental indenture, with each such series voting as a separate class (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, debt securities) and, subject to certain exceptions relating to waivers of past Defaults and rights of holders of notes to receive payment, any existing Default or Event of Default or compliance with any provision of the indenture or the debt securities issued thereunder (including the notes) or any Guarantee thereof may be waived with respect to each series of debt securities with the consent of the holders of a majority in aggregate principal amount of the then-outstanding debt securities of such series voting as a separate class (including, without limitation, consents obtained in connection with a purchase of, or tender offer or exchange offer for, debt securities).

Without the consent of each holder of the outstanding debt securities affected, an amendment, supplement or waiver may not (with respect to any debt securities held by a non-consenting holder):

(1) change the Stated Maturity of the principal of, or any installment of principal of or interest on, any debt security, or reduce the principal amount thereof or the rate of interest thereon or any premium payable upon the redemption thereof, or reduce the amount of the principal of an original issue discount security that would be due and payable upon a declaration of acceleration of the maturity thereof pursuant to the indenture, or change any place of payment where, or the coin or currency in which, any debt security or any premium or the interest thereon is payable, or impair the right to institute suit for the enforcement of any such payment on or after the Stated Maturity thereof (or, in the case of redemption, on or after the redemption date therefor);

(2) reduce the percentage in principal amount of the then-outstanding debt securities of any series, the consent of whose holders is required for any such amendment, supplement or waiver;

(3) modify any of the provisions set forth in (i) the provisions of the indenture related to the holder s unconditional right to receive principal, premium, if any, or Liquidated Damages, if any, and interest on the debt securities or (ii) the provisions of the indenture related to the waiver of past Defaults under such indenture except to increase any such percentage or to provide that certain other provisions of such indenture cannot be modified or waived without the consent of the holder of each then-outstanding debt security affected thereby;

(4) waive a redemption payment with respect to any debt security; *provided*, *however*, that any purchase or repurchase of debt securities shall not be deemed a redemption of the debt securities;

(5) release any Subsidiary Guarantor from any of its obligations under its Subsidiary Guarantee or the indenture, except in accordance with the terms of such indenture (as supplemented by any supplemental indenture); or

(6) make any change in the foregoing amendment and waiver provisions of the indenture.

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Notwithstanding the foregoing, without the consent of any holder of debt securities, PDC, the Subsidiary Guarantors (if any) and the trustee may amend or supplement the indenture or the debt securities or the Guarantees thereof issued thereunder to:

(1) cure any ambiguity or defect or to correct or supplement any provision therein that may be inconsistent with any other provision therein;

(2) evidence the succession of another person or entity to PDC and the assumption by any such successor of the covenants of PDC therein and, to the extent applicable, to the debt securities;

(3) provide for uncertificated debt securities in addition to or in place of certificated debt securities;

(4) add a Subsidiary Guarantee and cause any person or entity to become a Subsidiary Guarantor, and/or to evidence the succession of another person or entity to a Subsidiary Guarantor and the assumption by any such successor of the Subsidiary Guarantee of such Subsidiary Guarantor therein and, to the extent applicable, endorsed upon any debt securities of any series;

(5) secure the debt securities of any series;

(6) add to the covenants of PDC such further covenants, restrictions, conditions or provisions as PDC shall consider to be appropriate for the benefit of the holders of all or any series of debt securities (and if such covenants, restrictions, conditions or provisions are to be for the benefit of less than all series of debt securities, stating that such covenants are expressly being included solely for the benefit of such series) or to surrender any right or power therein conferred upon PDC and to make the occurrence, or the occurrence and continuance, of a Default in any such additional covenants, restrictions, conditions or provisions an Event of Default permitting the enforcement of all or any of the several remedies provided in the indenture as set forth therein; *provided*, that in respect of any such additional covenant, restriction, condition or provision, such supplemental indenture may provide for a particular period of grace after Default (which period may be shorter or longer than that allowed in the case of other Defaults) or may provide for an immediate enforcement upon such an Event of Default or may limit the remedies available to the trustee upon such an Event of Default or may limit the right of the holders of a majority in aggregate principal amount of the debt securities of such series to waive such an Event of Default;

(7) make any change to any provision of the indenture that would provide any additional rights or benefits to the holders of the debt securities issued thereunder or that does not adversely affect the rights or interests of any such holder;

(8) provide for the issuance of additional debt securities in accordance with the provisions set forth in the indenture on the date of such indenture;

(9) add any additional Defaults or Events of Default in respect of all or any series of debt securities;

(10) change or eliminate any of the provisions of the indenture; *provided* that any such change or elimination shall become effective only when there is no debt security outstanding of any series created prior to the execution of such supplemental indenture that is entitled to the benefit of such provision;

(11) establish the form or terms of debt securities of any series as permitted thereunder, including to reopen any series of any debt securities as permitted thereunder;

(12) evidence and provide for the acceptance of appointment thereunder by a successor trustee with respect to the debt securities of one or more series and to add to or change any of the provisions of the indenture as shall be necessary to provide for or facilitate the administration of the trusts thereunder by more than one trustee, pursuant to the requirements of such indenture;

(13) conform the text of the indenture (and/or any supplemental indenture) or any debt securities issued thereunder to any provision of a description of such debt securities appearing in a prospectus or prospectus supplement or an offering memorandum or offering circular pursuant to which such debt securities were offered to the extent that such provision was intended to be a verbatim recitation of a provision of such indenture (and/or any supplemental indenture) or any debt securities or Guarantees issued thereunder;

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(14) add a corporate co-issuer in accordance with the covenant set forth under the caption Covenants Merger, Consolidation or Sale of Substantially All Assets; or

(15) modify, eliminate or add to the provisions of the indenture to such extent as shall be necessary to effect the qualification of such indenture under the Trust Indenture Act, or under any similar federal statute subsequently enacted, and to add to such indenture such other provisions as may be expressly required under the Trust Indenture Act.

The consent of the holders is not necessary under the indenture to approve the particular form of any proposed amendment, supplement or waiver, but it is sufficient if such consent approves the substance thereof. After an amendment, supplement or waiver under the indenture becomes effective, PDC shall mail to the holders of debt securities affected thereby a notice briefly describing such amendment, supplement or waiver. However, the failure to give such notice to all such holders, or any defect therein, will not impair or affect the validity of the applicable amendment, supplement or waiver.

Satisfaction and Discharge

The indenture will be discharged and will cease to be of further effect as to all notes issued thereunder, when:

(1) either:

(a) all notes that have been authenticated, except lost, stolen or destroyed notes that have been replaced or paid and notes for whose payment money has been deposited in trust and thereafter repaid to PDC, have been delivered to the trustee for cancellation; or

(b) all notes that have not been delivered to the trustee for cancellation have become due and payable by reason of the mailing of a notice of redemption or otherwise or will become due and payable within one year and PDC or any Subsidiary Guarantor has irrevocably deposited or caused to be deposited with the trustee as trust funds in trust solely for the benefit of the holders, cash in U.S. dollars, non-callable Government Securities, or a combination of cash in U.S. dollars and non-callable Government Securities, in amounts as will be sufficient, without consideration of any reinvestment of interest, to pay and discharge the entire Indebtedness on the notes not delivered to the trustee for cancellation for principal, premium and Liquidated Damages, if any, and accrued interest to the date of maturity or redemption;

(2) no Default or Event of Default has occurred and is continuing on the date of the deposit (other than a Default or Event of Default resulting from the borrowing of funds to be applied to such deposit);

(3) such deposit will not result in a breach or violation of, or constitute a default under, any material agreement or instrument (other than the indenture) to which PDC or any Subsidiary Guarantor is a party or by which PDC or any Subsidiary Guarantor is bound;

(4) PDC or any Subsidiary Guarantor has paid or caused to be paid all sums payable by it under the indenture; and

(5) PDC has delivered irrevocable instructions to the trustee under the indenture to apply the deposited money toward the payment of the notes at maturity or on the redemption date, as the case may be.

In addition, PDC must deliver to the trustee (a) an Officers Certificate, stating that all conditions precedent set forth in clauses (1) through (5) above have been satisfied and (b) an opinion of counsel, stating that all conditions precedent set forth in clauses (3) and (5) above have been satisfied.

Concerning the Trustee

If the trustee becomes a creditor of PDC or any Subsidiary Guarantor, the indenture limits the right of the trustee to obtain payment of claims in certain cases, or to realize on certain property received in respect of any such claim as security or otherwise. The trustee will be permitted to engage in other transactions; however, if it acquires any conflicting interest it must eliminate such conflict within 90 days, apply to the SEC for permission to continue as trustee (if the indenture has been qualified under the Trust Indenture Act) or resign.

The holders of a majority in aggregate principal amount of the then outstanding notes will have the right to direct the time, method and place of conducting any proceeding for exercising any remedy available to the trustee, subject to certain exceptions. The indenture provides that in case an Event of Default occurs and is continuing, the trustee will be required, in the exercise of its power, to use the degree of care of a prudent man in the conduct of his own affairs. Subject to such provisions, the trustee will be under no obligation to exercise any of its rights or powers under the indenture at the request of any holder of notes, unless such holder has offered to the trustee security and indemnity satisfactory to it against any loss, liability or expense.

Additional Information

Anyone who receives this prospectus may obtain a copy of the indenture and the Registration Rights Agreement without charge by writing to Petroleum Development Corporation, 120 Genesis Boulevard, Bridgeport, West Virginia 26330, Attention: Corporate Secretary.

Governing Law

The indenture, the notes and the Subsidiary Guarantees are governed by the laws of the State of New York.

Book-Entry, Delivery and Form

Except as set forth below, notes will be issued in registered, global form in minimum denominations of $2,000 and integral multiples of $1,000 in excess thereof (the *Global Notes*).

The Global Notes will be deposited upon issuance with the trustee as custodian for The Depository Trust Company (*DTC*), in New York, New York, and registered in the name of DTC or its nominee, in each case for credit to an account of a direct or indirect participant in DTC as described below. The Global Notes may also be held through Euroclear Bank, S.A./N.V. as the operator of the Euroclear System (*Euroclear*) and Clearstream Banking, S.A. (*Clearstream*) (as indirect participants in DTC).

Except as set forth below, the Global Notes may be transferred, in whole and not in part, only to another nominee of DTC or to a successor of DTC or its nominee. Beneficial interests in the Global Notes may not be exchanged for definitive notes in registered certificated form (*Certificated Notes)* except in the limited circumstances described below. See Exchange of Global Notes for Certificated Notes. Except in the limited circumstances described below, owners of beneficial interests in the Global Notes will not be entitled to receive physical delivery of notes in certificated form. Transfers of beneficial interests in the Global Notes will be subject to the applicable rules and procedures of DTC and its direct or indirect participants (including, if applicable, those of Euroclear and Clearstream), which may change from time to time.

Depository Procedures

The following description of the operations and procedures of DTC, Euroclear and Clearstream are provided solely as a matter of convenience. These operations and procedures are solely within the control of the respective settlement systems and are subject to changes by them. PDC takes no responsibility for these operations and procedures and urges investors to contact the system or their participants directly to discuss these matters.

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DTC has advised PDC that DTC is a limited-purpose trust company created to hold securities for its participating organizations (collectively, the *Participants*) and to facilitate the clearance and settlement of transactions in those securities between the Participants through electronic book-entry changes in accounts of its Participants. The Participants include securities brokers and dealers (including the initial purchasers), banks, trust companies, clearing corporations and certain other organizations. Access to DTC s system is also available to other entities such as banks, brokers, dealers and trust companies that clear through or maintain a custodial relationship with a Participant, either directly or indirectly (collectively, the *Indirect Participants*). Persons who are not Participants may beneficially own securities held by or on behalf of DTC only through the Participants or the Indirect Participants. The ownership interests in, and transfers of ownership interests in, each security held by or on behalf of DTC are recorded on the records of the Participants and Indirect Participants.

DTC has also advised PDC that, pursuant to procedures established by it:

(1) upon deposit of the Global Notes, DTC will credit the accounts of the Participants designated by the initial purchasers with portions of the principal amount of the Global Notes; and

(2) ownership of these interests in the Global Notes will be shown on, and the transfer of ownership of these interests will be effected only through, records maintained by DTC (with respect to the Participants) or by the Participants and the Indirect Participants (with respect to other owners of beneficial interest in the Global Notes).

Investors in the Global Notes who are Participants may hold their interests therein directly through DTC. Investors in the Global Notes who are not Participants may hold their interests therein indirectly through organizations (including Euroclear and Clearstream) which are Participants. Euroclear and Clearstream will hold interests in the Global Notes on behalf of their participants through customers securities accounts in their respective names on the books of their respective depositories, which are Euroclear Bank S.A./N.V., as operator of Euroclear, and Citibank, N.A., as operator of Clearstream. All interests in a Global Note, including those held through Euroclear or Clearstream, may be subject to the procedures and requirements of DTC. Those interests held through Euroclear or Clearstream may also be subject to the procedures and requirements of such systems. The laws of some states require that certain Persons take physical delivery in definitive form of securities that they own. Consequently, the ability to transfer beneficial interests in a Global Note to such Persons will be limited to that extent. Because DTC can act only on behalf of the Participants, which in turn act on behalf of the Indirect Participants, the ability of a Person having beneficial interests in a Global Note to pledge such interests to Persons that do not participate in the DTC system, or otherwise take actions in respect of such interests, may be affected by the lack of a physical certificate evidencing such interests.

Except as described below, owners of interests in the Global Notes will not have notes registered in their names, will not receive physical delivery of notes in certificated form and will not be considered the registered owners or *holders* thereof under the indenture for any purpose.

Payments in respect of the principal of, and interest and premium and Liquidated Damages, if any, on a Global Note registered in the name of DTC or its nominee will be payable to DTC in its capacity as the registered holder under the indenture. Under the terms of the indenture, PDC and the trustee will treat the Persons in whose names the notes, including the Global Notes, are registered as the owners thereof for the purpose of receiving payments and for all other purposes. Consequently, neither PDC, the trustee nor any agent of PDC or the trustee has or will have any responsibility or liability for:

(1) any aspect of DTC s records or any Participant s or Indirect Participant s records relating to or payments made on account of beneficial ownership interest in the Global Notes or for maintaining, supervising or reviewing any of DTC s records or any Participant s or Indirect Participant s records relating to the beneficial ownership interests in the Global Notes; or

(2) any other matter relating to the actions and practices of DTC or any of its Participants or Indirect Participants.

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DTC has advised PDC that its current practice, upon receipt of any payment in respect of securities such as the notes (including principal and interest), is to credit the accounts of the relevant Participants with the payment on the payment date unless DTC has reason to believe that it will not receive payment on such payment date. Each relevant Participant is credited with an amount proportionate to its beneficial ownership of an interest in the principal amount of the relevant security as shown on the records of DTC. Payments by the Participants and the Indirect Participants to the beneficial owners of notes will be governed by standing instructions and customary practices and will be the responsibility of the Participants or the Indirect Participants and will not be the responsibility of DTC, the trustee or PDC. Neither PDC nor the trustee will be liable for any delay by DTC or any of its Participants or the Indirect Participants in identifying the beneficial owners of the notes, and PDC and the trustee may conclusively rely on and will be protected in relying on instructions from DTC or its nominee for all purposes.

Transfers between Participants in DTC will be effected in accordance with DTC s procedures, and will be settled in same-day funds, and transfers between participants in Euroclear and Clearstream will be effected in accordance with their respective rules and operating procedures.

Cross-market transfers between the Participants in DTC, on the one hand, and Euroclear or Clearstream participants, on the other hand, will be effected through DTC in accordance with DTC s rules on behalf of Euroclear or Clearstream, as the case may be, by their respective depositaries; however, such cross-market transactions will require delivery of instructions to Euroclear or Clearstream, as the case may be, by the counterparty in such system in accordance with the rules and procedures and within the established deadlines (Brussels time) of such system. Euroclear or Clearstream, as the case may be, will, if the transaction meets its settlement requirements, deliver instructions to its respective depositary to take action to effect final settlement on its behalf by delivering or receiving interests in the relevant Global Note in DTC, and making or receiving payment in accordance with normal procedures for same-day funds settlement applicable to DTC. Euroclear participants and Clearstream participants may not deliver instructions directly to the depositories for Euroclear or Clearstream.

DTC has advised PDC that it will take any action permitted to be taken by a holder of notes only at the direction of one or more Participants to whose account DTC has credited the interests in the Global Notes and only in respect of such portion of the aggregate principal amount of the notes as to which such Participant or Participants has or have given such direction. However, if there is an Event of Default under the notes, DTC reserves the right to exchange the Global Notes for legended notes in certificated form, and to distribute such notes to its Participants.

Although DTC, Euroclear and Clearstream have agreed to the foregoing procedures to facilitate transfers of interests in the Global Notes among participants in DTC, Euroclear and Clearstream, they are under no obligation to perform or to continue to perform such procedures, and may discontinue such procedures at any time. Neither PDC nor the trustee nor any of their respective agents will have any responsibility for the performance by DTC, Euroclear or Clearstream or their respective participants or indirect participants of their respective obligations under the rules and procedures governing their operations.

Exchange of Global Notes for Certificated Notes

A Global Note is exchangeable for Certificated Notes if:

(1) DTC (a) notifies PDC that it is unwilling or unable to continue as depositary for the Global Notes or (b) has ceased to be a clearing agency registered under the Exchange Act, and in each case PDC fails to appoint a successor depositary;

(2) PDC, at its option, notifies the trustee in writing that it elects to cause the issuance of Certificated Notes (DTC has advised PDC that, in such event, under its current practices, DTC would notify its participants of PDC s request, but will only withdraw beneficial interests from a Global Note at the request of each DTC participant); or

(3) there will have occurred and be continuing a Default or Event of Default with respect to the notes.

In addition, beneficial interests in a Global Note may be exchanged for Certificated Notes upon prior written notice given to the trustee by or on behalf of DTC in accordance with the indenture. In all cases, Certificated Notes delivered in exchange for any Global Note or beneficial interests in Global Notes will be registered in the names, and issued in any approved denominations, requested by or on behalf of the depositary (in accordance with its customary procedures).

Same Day Settlement and Payment

PDC will make payments in respect of the notes represented by the Global Notes (including principal, premium, if any, interest and Liquidated Damages, if any) by wire transfer of immediately available funds to the accounts specified by DTC or its nominee. PDC will make all payments of principal, interest and premium and Liquidated Damages, if any, with respect to Certificated Notes by wire transfer of immediately available funds to the accounts specified by the holders thereof or, if no such account is specified, by mailing a check to each such holder s registered address. The notes represented by the Global Notes are expected to be eligible to trade in DTC s Same-Day Funds Settlement System, and any permitted secondary market trading activity in such notes will, therefore, be required by DTC to be settled in immediately available funds. PDC expects that secondary trading in any Certificated Notes will also be settled in immediately available funds.

Because of time zone differences, the securities account of a Euroclear or Clearstream participant purchasing an interest in a Global Note from a Participant in DTC will be credited, and any such crediting will be reported to the relevant Euroclear or Clearstream participant, during the securities settlement processing day (which must be a Business Day for Euroclear and Clearstream) immediately following the settlement date of DTC. DTC has advised PDC that cash received in Euroclear or Clearstream as a result of sales of interests in a Global Note by or through a Euroclear or Clearstream participant to a Participant in DTC will be received with value on the settlement date of DTC but will be available in the relevant Euroclear or Clearstream cash account only as of the Business Day for Euroclear or Clearstream following DTC s settlement date.

Definitions

Acquired Debt means, with respect to any specified Person:

(1) Indebtedness of any other Person existing at the time such other Person is merged with or into or became a Subsidiary of such specified Person, regardless of whether such Indebtedness is incurred in connection with, or in contemplation of, such other Person merging with or into, or becoming a Restricted Subsidiary of, such specified Person, but excluding Indebtedness which is extinguished, retired or repaid in connection with such Person merging with or becoming a Subsidiary of such specified Person; and

(2) Indebtedness secured by a Lien encumbering any asset acquired by such specified Person.

Acquired Subordinated Indebtedness means Subordinated Debt of PDC or any Restricted Subsidiary that is Acquired Debt and was not incurred in connection with, or in contemplation of, another Person merging with or into, or becoming a Restricted Subsidiary of, PDC or any of its Subsidiaries.

Additional Assets means:

(1) any property or assets (other than Indebtedness and Capital Stock) to be used by PDC or a Restricted Subsidiary in a Related Business;

(2) the Capital Stock of a Person that becomes a Restricted Subsidiary as a result of the acquisition of such Capital Stock by PDC or another Restricted Subsidiary;

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(3) Capital Stock constituting a minority interest in any Person that at such time is a Restricted Subsidiary; or

(4) Capital Stock of any Restricted Subsidiary; provided that all the Capital Stock of such Subsidiary held by PDC or any of its Restricted Subsidiaries shall entitle PDC or such Restricted Subsidiary to not less than a pro rata portion of all dividends or other distributions made by such Subsidiary upon any of such Capital Stock;

provided, *however*, that, in the case of clauses (2), (3) and (4), such Subsidiary is primarily engaged in a Related Business.

Adjusted Consolidated Net Tangible Assets means (without duplication), as of the date of determination, the remainder of:

(a) the sum of:

(i) discounted future net revenues from proved oil and gas reserves of PDC and its Restricted Subsidiaries calculated in accordance with SEC guidelines before any provincial, territorial, state, federal or foreign income taxes, as estimated by PDC in a reserve report prepared as of the end of PDC s most recently completed fiscal year for which audited financial statements are available and giving effect to applicable Oil and Natural Gas Hedging Contracts, as increased by, as of the date of determination, the estimated discounted future net revenues from:

(A) estimated proved oil and gas reserves acquired since such year end, which reserves were not reflected in such year end reserve report, and

(B) estimated oil and gas reserves attributable to upward revisions of estimates of proved oil and gas reserves (including previously estimated development costs incurred during the period and the accretion of discount since the prior period end) since such year end due to exploration, development, exploitation or other activities, in each case calculated in accordance with SEC guidelines,

and decreased by, as of the date of determination, the estimated discounted future net revenues from:

(C) estimated proved oil and gas reserves reflected in such reserve report produced or disposed of since such year end, and

(D) estimated oil and gas reserves attributable to downward revisions of estimates of proved oil and gas reserves reflected in such reserve report since such year end due to changes in geological conditions or other factors which would, in accordance with standard industry practice, cause such revisions, in each case calculated substantially in accordance with SEC guidelines, in each case as estimated by PDC s petroleum engineers or any independent petroleum engineers engaged by PDC for that purpose;

(ii) the capitalized costs that are attributable to Oil and Gas Properties of PDC and its Restricted Subsidiaries to which no proved oil and gas reserves are attributable, based on PDC s books and records as of a date no earlier than the date of PDC s latest available annual or quarterly financial statements;

(iii) the Net Working Capital (excluding, to the extent included in the determination of discounted future net revenues under clause (i)(A) above, any adjustments made pursuant to FAS 143) on a date no earlier than the date of PDC s latest annual or quarterly financial statements; and

(iv) the greater of:

(A) the net book value of other tangible assets of PDC and its Restricted Subsidiaries, as of a date no earlier than the date of PDC s latest annual or quarterly financial statement, and

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(B) the appraised value, as estimated by independent appraisers, of other tangible assets of PDC and its Restricted Subsidiaries, as of a date no earlier than the date of PDC s latest audited financial statements (*provided* that PDC shall not be required to obtain such appraisal solely for the purpose of determining this value); *minus*

(b) the sum of:

(i) the net book value of shares of stock of any class of Capital Stock of a Restricted Subsidiary that are not owned by PDC or another Restricted Subsidiary;

(ii) any net gas balancing liabilities of PDC and its Restricted Subsidiaries reflected in PDC s latest audited financial statements;

(iii) to the extent included in (a)(i) above, the discounted future net revenues, calculated in accordance with SEC guidelines (utilizing the prices utilized in PDC s year end reserve report), attributable to reserves which are required to be delivered to third parties to fully satisfy the obligations of PDC and its Restricted Subsidiaries with respect to Volumetric Production Payments (determined, if applicable, using the schedules specified with respect thereto); and

(iv) the discounted future net revenues, calculated in accordance with SEC guidelines, attributable to reserves subject to Dollar-Denominated Production Payments which, based on the estimates of production and price assumptions included in determining the discounted future net revenues specified in (a)(i) above, would be necessary to fully satisfy the payment obligations of PDC and its Subsidiaries with respect to Dollar-Denominated Production Payments (determined, if applicable, using the schedules specified with respect thereto).

If PDC changes its method of accounting from the full cost or a similar method to the successful efforts method of accounting, *Adjusted Consolidated Net Tangible Assets* will continue to be calculated as if PDC were still using the full cost or a similar method of accounting.

Affiliate of any specified Person means any other Person directly or indirectly controlling or controlled by or under direct or indirect common control with such specified Person. For purposes of this definition, control, as used with respect to any Person, means the possession, directly or indirectly, of the power to direct or cause the direction of the management or policies of such Person, whether through the ownership of voting securities, by agreement or otherwise. For purposes of this definition, the terms controlling, controlled by and under common control with have correlative meanings.

Asset Sale means:

(1) the sale, lease, conveyance or other disposition of any assets or rights (including by way of a Production Payment or a sale and leaseback transaction); *provided* that the sale, lease, conveyance or other disposition of all or substantially all of the assets of PDC and its Restricted Subsidiaries taken as a whole will be governed by the provisions of the indenture described above under the caption Repurchase at the Option of Holders Change of Control and/or the provisions described above under the caption Covenants Merger, Consolidation or Sale of Substantially All Assets and not by the provisions of the Asset Sale covenant; and

(2) the issuance of Equity Interests in any of PDC s Restricted Subsidiaries (other than directors qualifying shares) or the sale of Equity Interests held by PDC or its Subsidiaries in any of its Subsidiaries.

Notwithstanding the preceding, none of the following items will be deemed to be an Asset Sale:

(1) any single transaction or series of related transactions that involves assets having a Fair Market Value of less than $15.0 million;

(2) a transfer of assets between or among PDC and its Restricted Subsidiaries;

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(3) an issuance of Equity Interests by a Restricted Subsidiary to PDC or to a Restricted Subsidiary;

(4) the sale, lease or other disposition of equipment, inventory, products, services, accounts receivable or other assets in the ordinary course of business, including in connection with any compromise, settlement or collection of accounts receivable, and any sale or other disposition of damaged, worn-out or obsolete assets or assets that are no longer useful in the conduct of the business of PDC and its Restricted Subsidiaries;

(5) the sale or other disposition of cash or Cash Equivalents;

(6) a Restricted Payment that does not violate the covenant described above under the caption Covenants Restricted Payments, including the issuance or sale of Equity Interests or the sale, lease or other disposition of products, services, equipment, inventory, accounts receivable or other assets pursuant to any such Restricted Payment;

(7) the consummation of a Permitted Investment, including, without limitation, unwinding any Hedging Obligations, and including the issuance or sale of Equity Interests or the sale, lease or other disposition of products, services, equipment, inventory, accounts receivable or other assets pursuant to any such Permitted Investment;

(8) a disposition of Hydrocarbons or mineral products inventory in the ordinary course of business;

(9) the farm-out, lease or sublease of developed or undeveloped crude oil or natural gas properties owned or held by PDC or any Restricted Subsidiary in exchange for crude oil and natural gas properties owned or held by another Person;

(10) the creation or perfection of a Lien (but not, except as contemplated in clause (11) below, the sale or other disposition of the properties or assets subject to such Lien);

(11) the creation or perfection of a Permitted Lien and the exercise by any Person in whose favor a Permitted Lien is granted of any of its rights in respect of that Permitted Lien;

(12) the licensing or sublicensing of intellectual property, including, without limitation, licenses for seismic data, in the ordinary course of business and which do not materially interfere with the business of PDC and its Restricted Subsidiaries;

(13) surrender or waiver of contract rights or the settlement, release or surrender of contract, tort or other claims of any kind; and

(14) the disposition of oil and natural gas properties in connection with tax credit transactions complying with Section 29 of the Internal Revenue Code or any successor or analogous provisions of the Internal Revenue Code.

Beneficial Owner has the meaning assigned to such term in Rule 13d-3 and Rule 13d-5 under the Exchange Act, except that in calculating the beneficial ownership of any particular person (as that term is used in Section 13(d)(3) of the Exchange Act), such person will be deemed to have beneficial ownership of all securities that such person has the right to acquire by conversion or exercise of other securities, whether such right is currently exercisable or is exercisable only after the passage of time or upon the occurrence of a subsequent condition. The terms Beneficially Owns, Beneficially Owned and Beneficially Owning will have a corresponding meaning.

Board of Directors means:

(1) with respect to a corporation, the board of directors of the corporation or any committee thereof duly authorized to act on behalf of such board;

(2) with respect to a partnership, the board of directors of the general partner of the partnership;

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(3) with respect to a limited liability company, the managers or managing member or members of such limited liability company (as applicable) or any duly authorized committee of managers or managing members (as applicable) thereof; and

(4) with respect to any other Person, the board of directors or duly authorized committee of such Person serving a similar function.

Business Day means any day other than a Legal Holiday.

Capital Lease Obligation means, at the time any determination is to be made, the amount of the liability in respect of a capital lease that would at that time be required to be capitalized on a balance sheet in accordance with GAAP, and the Stated Maturity thereof shall be the date of the last payment of rent or any other amount due under such lease prior to the first date upon which such lease may be prepaid by the lessee without payment of a penalty.

Capital Stock means:

(1) in the case of a corporation, corporate stock;

(2) in the case of an association or business entity, any and all shares, interests, participations, rights or other equivalents (however designated) of corporate stock;

(3) in the case of a partnership or limited liability company, partnership interests (whether general or limited) or membership interests; and

(4) any other interest or participation that confers on a Person the right to receive a share of the profits and losses of, or distributions of assets of, the issuing Person, but excluding from all of the foregoing any debt securities convertible into Capital Stock, regardless of whether such debt securities include any right of participation with Capital Stock.

Cash Equivalents means:

(1) United States dollars;

(2) Government Securities having maturities of not more than one year from the date of acquisition;

(3) marketable general obligations issued by any state of the United States of America or any political subdivision of any such state or any public instrumentality thereof maturing within one year from the date of acquisition thereof and, at the time of acquisition thereof, having a credit rating of A or better from either S&P or Moody s;

(4) certificates of deposit, demand deposit accounts and eurodollar time deposits with maturities of one year or less from the date of acquisition, bankers acceptances with maturities not exceeding one year and overnight bank deposits, in each case, with any domestic commercial bank having capital and surplus in excess of $500.0 million and a Thomson Bank Watch Rating of B or better;

(5) repurchase obligations with a term of not more than seven days for underlying securities of the types described in clauses (2), (3) and (4) above entered into with any financial institution meeting the qualifications specified in clause (4) above;

(6) commercial paper having one of the two highest ratings obtainable from Moody s or S&P and, in each case, maturing within one year after the date of acquisition; and

(7) money market funds at least 95% of the assets of which constitute Cash Equivalents of the kinds described in clauses (1) through (6) of this definition; and

(8) deposits in any currency available for withdrawal on demand with any commercial bank that is organized under the laws of any country in which PDC or any Restricted Subsidiary maintains its chief executive office or is engaged in the Related Business, *provided* that all such deposits are made in such accounts in the ordinary course of business.

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Change of Control means:

(1) any person or group of related persons (as such terms are used in Section 13(d) of the Exchange Act), other than a Parent, is or becomes a Beneficial Owner, directly or indirectly, of more than 50% of the total voting power of the Voting Stock of PDC (or its successor by merger, consolidation or purchase of all or substantially all of its assets) (for the purposes of this clause, such person or group shall be deemed to Beneficially Own any Voting Stock of PDC held by an entity, if such person or group Beneficially Owns, directly or indirectly, more than 50% of the voting power of the Voting Stock of such entity);

(2) the first day on which a majority of the members of the Board of Directors of PDC are not Continuing Directors;

(3) the direct or indirect sale, lease, transfer, conveyance or other disposition (other than by way of merger or consolidation), in one or a series of related transactions, of all or substantially all of the assets of PDC and its Restricted Subsidiaries taken as a whole to any person (as such term is used in Section 13(d) of the Exchange Act); or

(4) the adoption of a plan or proposal for the liquidation or dissolution of PDC.

Consolidated Cash Flow means, with respect to any specified Person for any period, the Consolidated Net Income of such Person for such period *plus*, without duplication:

(1) an amount equal to any extraordinary loss *plus* any net loss realized by such Person or any of its Restricted Subsidiaries in connection with an Asset Sale (together with any related provision for taxes and any related non-recurring charges relating to any premium or penalty paid, write-off of deferred financing costs or other financial recapitalization charges in connection with redeeming or retiring any Indebtedness prior to its Stated Maturity), to the extent that such losses were deducted in computing such Consolidated Net Income; *plus*

(2) provision for taxes based on income or profits of such Person and its Restricted Subsidiaries for such period, to the extent that such provision for taxes was deducted in computing such Consolidated Net Income; *plus*

(3) the Fixed Charges of such Person and its Restricted Subsidiaries for such period, to the extent that such Fixed Charges were deducted in computing such Consolidated Net Income; *plus*

(4) exploration and abandonment expense (if applicable) to the extent deducted in calculating Consolidated Net Income; *plus*

(5) depreciation, depletion, amortization (including amortization of intangibles but excluding amortization of prepaid cash expenses that were paid in a prior period), impairment, other non-cash expenses and other non-cash items (excluding any such non-cash expense to the extent that it represents an accrual of or reserve for cash expenses in any future period or amortization of a prepaid cash expense that was paid in a prior period) of such Person and its Restricted Subsidiaries for such period to the extent that such depreciation, depletion, amortization, impairment and other non-cash expenses were deducted in computing such Consolidated Net Income; *plus*

(6) any interest expense attributable to any Oil and Natural Gas Hedging Contract, to the extent that such interest expense was deducted in computing such Consolidated Net Income; *plus*

(7) the accretion of interest charges on future plugging and abandonment obligations and future retirement benefits, to the extent such charges were deducted in computing such Consolidated Net Income; *minus*

(8) non-cash items increasing such Consolidated Net Income for such period, other than items that were accrued in the ordinary course of business, and *minus*

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(9) the sum of (a) the amount of deferred revenues that are amortized during such period and are attributable to reserves that are subject to Volumetric Production Payments and (b) amounts recorded in accordance with GAAP as repayments of principal and interest pursuant to Dollar-Denominated Production Payments;

in each case, on a consolidated basis and determined in accordance with GAAP.

Notwithstanding the foregoing, the provision for taxes on the income or profits of, and the depreciation, depletion and amortization and other non-cash charges and expenses of, a Restricted Subsidiary of the referent Person shall be added to Consolidated Net Income to compute Consolidated Cash Flow only (a) to the extent (and in the same proportion) that the Net Income of such Restricted Subsidiary was included in calculating the Consolidated Net Income of such Person and (b) if a corresponding amount would be permitted at the date of determination to be dividended or distributed to the referent Person by such Restricted Subsidiary without prior governmental approval (that has not been obtained), and without direct or indirect restriction pursuant to the terms of its charter and all agreements, instruments, judgments, decrees, orders, statutes, rules and governmental regulations applicable to that Restricted Subsidiary or its stockholders (without regard to any restrictions existing by reason of, or any governmental approvals necessary pursuant to, any law, rule, regulation, order or decree that is generally applicable to all Persons operating in any jurisdiction in which PDC or any of its Restricted Subsidiaries are conducting business so long as there is in effect no specific order, decree or other prohibition pursuant to any such law, rule or regulation in such jurisdiction limiting the payment of a dividend or similar distribution by such Restricted Subsidiary); *provided*, *however*, that the operation of this clause (b) shall be suspended with respect to any Restricted Subsidiary that is acquired by PDC or any of its Restricted Subsidiaries (regardless of whether such acquisition is effected pursuant to a merger or otherwise) (such Restricted Subsidiary being referred to as a *Newly Acquired Restricted Subsidiary*), but such suspension shall cease immediately after the first six months following such acquisition.

Consolidated Net Income means, with respect to any specified Person for any period, the aggregate of the Net Income of such Person and its Restricted Subsidiaries for such period, on a consolidated basis, determined in accordance with GAAP; *provided* that:

(1) the Net Income (but not loss) of any Person that is not a Restricted Subsidiary or that is accounted for by the equity method of accounting will be included only to the extent of the amount of dividends or similar distributions paid in cash to the specified Person or a Restricted Subsidiary of the Person;

(2) the Net Income of any Restricted Subsidiary will be excluded to the extent that the declaration or payment of dividends or similar distributions by that Restricted Subsidiary of that Net Income is not at the date of determination permitted without any prior governmental approval (that has not been obtained) or, directly or indirectly, by operation of the terms of its charter or any agreement, instrument, judgment, decree, order, statute, rule or governmental regulation applicable to that Restricted Subsidiary or its stockholders (without regard to any restrictions existing by reason of, or any governmental approvals necessary pursuant to, any law, rule, regulation, order or decree that is generally applicable to all Persons operating in any jurisdiction in which PDC or any of its Restricted Subsidiaries are conducting business so long as there is in effect no specific order, decree or other prohibition pursuant to any such law, rule or regulation in such jurisdiction limiting the payment of a dividend or similar distribution by such Restricted Subsidiary); *provided*, *however*, that the operation of this clause (2) shall be suspended with respect to any Newly Acquired Restricted Subsidiary, but such suspension shall cease immediately after the first six months following such acquisition;

(3) the cumulative effect of a change in accounting principles will be excluded;

(4) any gain (loss) realized upon the sale or other disposition of any property, plant or equipment of such Person or its consolidated Restricted Subsidiaries (including pursuant to any sale or leaseback transaction) which is not sold or otherwise disposed of in the ordinary course of business and any gain (loss) realized upon the sale or other disposition of any Capital Stock of any Person will be excluded;

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(5) any asset impairment writedowns on Oil and Gas Properties under GAAP or SEC guidelines will be excluded;

(6) any non-cash mark-to-market adjustments to assets or liabilities resulting in unrealized gains or losses in respect of Hedging Obligations (including those resulting from the application of SFAS 133) shall be excluded; and

(7) to the extent deducted in the calculation of Net Income, any non-cash or nonrecurring charges associated with any premium or penalty paid, write-off of deferred financing costs or other financial recapitalization charges in connection with redeeming or retiring any Indebtedness will be excluded.

Consolidated Net Worth means, with respect to any specified Person as of any date, the sum of:

(1) the consolidated equity of the common stockholders of such Person and its consolidated Subsidiaries as of such date; *plus*

(2) the respective amounts reported on such Person s balance sheet as of such date with respect to any series of preferred stock (other than Disqualified Stock) that by its terms is not entitled to the payment of dividends unless such dividends may be declared and paid only out of net earnings in respect of the year of such declaration and payment, but only to the extent of any cash received by such Person upon issuance of such preferred stock.

Consolidated Tangible Assets means, with respect to any Person as of any date, the amount which, in accordance with GAAP, would be set forth under the caption Total Assets (or any like caption) on a consolidated balance sheet of such Person and its Restricted Subsidiaries, less all goodwill, patents, tradenames, trademarks, copyrights, franchises, experimental expenses, organization expenses and any other amounts classified as intangible assets in accordance with GAAP.

Continuing Directors means, as of any date of determination, any member of the Board of Directors of PDC who:

(1) was a member of such Board of Directors on the Issue Date; or

(2) was nominated for election or elected to such Board of Directors with the approval of a majority of the Continuing Directors who were members of such Board of Directors at the time of such nomination or election.

Credit Facilities means, with respect to PDC or any of its Restricted Subsidiaries, one or more debt facilities (including, without limitation, the Senior Credit Agreement), commercial paper facilities or Debt Issuances providing for revolving credit loans, term loans, receivables financing (including through the sale of receivables to any lenders, other financiers or to special purpose entities formed to borrow from (or sell such receivables to) any lenders or other financiers against such receivables), letters of credit, bankers acceptances, other borrowings or Debt Issuances, in each case, as amended, restated, modified, renewed, extended, refunded, replaced or refinanced (in each case, without limitation as to amount), in whole or in part, from time to time (including through one or more Debt Issuances).

Currency Agreement means in respect of a Person any foreign exchange contract, currency swap agreement or other similar agreement as to which such Person is a party or a beneficiary.

Debt Issuances means, with respect to PDC or any Restricted Subsidiary, one or more issuances after the Issue Date of Indebtedness evidenced by notes, debentures, bonds or other similar securities or instruments.

Default means any event which is, or after notice or passage of time or both would be, an Event of Default.

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Disqualified Stock means any Capital Stock that, by its terms (or by the terms of any security into which it is convertible, or for which it is exchangeable, in each case at the option of the holder of the Capital Stock), or upon the happening of any event, matures or is mandatorily redeemable, pursuant to a sinking fund obligation or otherwise, or redeemable at the option of the holder of the Capital Stock, in whole or in part, on or prior to the date that is 91 days after the date on which the notes mature. Notwithstanding the preceding sentence, any Capital Stock that would constitute Disqualified Stock solely because the holders of the Capital Stock have the right to require PDC to repurchase such Capital Stock upon the occurrence of a Change of Control or an Asset Sale will not constitute Disqualified Stock if the terms of such Capital Stock provide that PDC may not repurchase or redeem any such Capital Stock pursuant to such provisions unless such repurchase or redemption complies with the covenant described above under the caption Covenants Restricted Payments. The amount of Disqualified Stock deemed to be outstanding at any time for purposes of the indenture will be the maximum amount that PDC and its Restricted Subsidiaries may become obligated to pay upon the maturity of, or pursuant to any mandatory redemption provisions of, such Disqualified Stock, exclusive of accrued dividends.

Dollar-Denominated Production Payments means production payment obligations recorded as liabilities in accordance with GAAP, together with all undertakings and obligations in connection therewith.

Domestic Restricted Subsidiary means any Restricted Subsidiary that was formed under the laws of the United States or any state of the United States or the District of Columbia or that Guarantees or otherwise provides direct credit support for any Indebtedness of PDC or any Restricted Subsidiary.

Equity Interests means Capital Stock and all warrants, options or other rights to acquire Capital Stock (but excluding any debt security that is convertible into, or exchangeable for, Capital Stock).

Equity Offering means (1) an offering for cash by PDC of its Capital Stock (other than Disqualified Stock), or options, warrants or rights with respect to its Capital Stock or (2) a cash contribution to PDC s common equity capital from any Person.

Exchange Act means the Securities Exchange Act of 1934, as amended.

Existing Indebtedness means Indebtedness of PDC and its Subsidiaries (other than Indebtedness under the Senior Credit Agreement, the notes and the Subsidiary Guarantees) in existence on the Issue Date, until such amounts are repaid.

Fair Market Value means the value that would be paid by a willing buyer to an unaffiliated willing seller in a transaction not involving distress or necessity of either party, determined in good faith by the Board of Directors or management of PDC (unless otherwise provided in the indenture), which determination will be conclusive for all purposes under the indenture.

Farm-In Agreement means an agreement whereby a Person agrees to pay all or a share of the drilling, completion or other expenses of an exploratory or development well (which agreement may be subject to a maximum payment obligation, after which expenses are shared in accordance with the working or participation interest therein or in accordance with the agreement of the parties) or perform the drilling, completion or other operation on such well in exchange for an ownership interest in an oil or gas property.

Farm-Out Agreement means a Farm-In Agreement, viewed from the standpoint of the party that transfers an ownership interest to another.

Fixed Charge Coverage Ratio means with respect to any specified Person for any period, the ratio of the Consolidated Cash Flow of such Person for such period to the Fixed Charges of such Person for such period. In the event that the specified Person or any of its Restricted Subsidiaries incurs, assumes, guarantees, repays,

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repurchases, redeems, defeases or otherwise discharges any Indebtedness (other than ordinary working capital borrowings) or issues, repurchases or redeems preferred stock subsequent to the commencement of the period for which the Fixed Charge Coverage Ratio is being calculated and on or prior to the date on which the event for which the calculation of the Fixed Charge Coverage Ratio is made (the *Calculation Date*), then the Fixed Charge Coverage Ratio will be calculated giving pro forma effect to such incurrence, assumption, Guarantee, repayment, repurchase, redemption, defeasance or other discharge of Indebtedness, or such issuance, repurchase or redemption of preferred stock, and the use of the proceeds therefrom, as if the same had occurred at the beginning of the applicable four-quarter reference period.

In addition, for purposes of calculating the Fixed Charge Coverage Ratio:

(1) acquisitions that have been made by the specified Person or any of its Restricted Subsidiaries, including through mergers, consolidations or otherwise (including acquisitions of assets used or useful in a Related Business), or any Person or any of its Restricted Subsidiaries acquired by the specified Person or any of its Restricted Subsidiaries, and including any related financing transactions and including increases in ownership of Restricted Subsidiaries, during the four-quarter reference period or subsequent to such reference period and on or prior to the Calculation Date will be given pro forma effect as if they had occurred on the first day of the four-quarter reference period or, in the reasonable judgment of the chief accounting or chief financial officer of PDC, are reasonably expected to occur (regardless of whether those operating improvements or cost savings could then be reflected in pro forma financial statements prepared in accordance with Regulation S-X under the Securities Act or any other regulation or policy of the SEC related thereto);

(2) the Consolidated Cash Flow attributable to discontinued operations, as determined in accordance with GAAP, and operations or businesses (and ownership interests therein) disposed of prior to the Calculation Date, will be excluded;

(3) the Fixed Charges attributable to discontinued operations, as determined in accordance with GAAP, and operations or businesses (and ownership interests therein) disposed of prior to the Calculation Date, will be excluded, but only to the extent that the obligations giving rise to such Fixed Charges will not be obligations of the specified Person or any of its Restricted Subsidiaries following the Calculation Date;

(4) any Person that is a Restricted Subsidiary on the Calculation Date will be deemed to have been a Restricted Subsidiary at all times during such four-quarter period;

(5) any Person that is not a Restricted Subsidiary on the Calculation Date will be deemed not to have been a Restricted Subsidiary at any time during such four-quarter period; and

(6) if any Indebtedness bears a floating rate of interest, the interest expense on such Indebtedness will be calculated as if the rate in effect on the Calculation Date had been the applicable rate for the entire period (taking into account any Hedging Obligation applicable to such Indebtedness if such Hedging Obligation has a remaining term as at the Calculation Date in excess of 12 months).

Fixed Charges means, with respect to any specified Person for any period, the sum, without duplication, of:

(1) the consolidated interest expense of such Person and its Restricted Subsidiaries for such period, whether paid or accrued (excluding (i) any interest attributable to Production Payments and Reserve Sales, (ii) write-off of deferred financing costs and (iii) accretion of interest charges on future plugging and abandonment obligations, future retirement benefits and other obligations that do not constitute Indebtedness, but including, without limitation, amortization of debt issuance costs and original issue discount, noncash interest payments, the interest component of any deferred payment obligations other than that attributable to any Oil and Natural Gas Hedging Contract, the interest component of all payments associated with Capital Lease Obligations, commissions, discounts and other fees and charges incurred in respect of letter of credit or bankers acceptance financings), and net of the effect of all payments made or received pursuant to Interest Rate Agreements; *plus*

(2) the consolidated interest expense of such Person and its Restricted Subsidiaries that was capitalized during such period; *plus*

(3) any interest on Indebtedness of another Person that is guaranteed by the specified Person or one or more of its Restricted Subsidiaries or secured by a Lien on assets of such specified Person or one or more of its Restricted Subsidiaries, regardless of whether such Guarantee or Lien is called upon; *plus*

(4) all dividends, whether paid or accrued and regardless of whether in cash, on any series of preferred stock of such Person or any of its Restricted Subsidiaries, other than dividends on Equity Interests payable solely in Equity Interests of PDC (other than Disqualified Stock) or to PDC or a Restricted Subsidiary,

in each case, on a consolidated basis and in accordance with GAAP.

Foreign Subsidiary means any Restricted Subsidiary other than a Domestic Restricted Subsidiary.

GAAP means generally accepted accounting principles set forth in the opinions and pronouncements of the Accounting Principles Board of the American Institute of Certified Public Accountants, the opinions and pronouncements of the Public Company Accounting Oversight Board and in the statements and pronouncements of the Financial Accounting Standards Board or in such other statements by such other entity as have been approved by a significant segment of the accounting profession, which are in effect from time to time. All ratios and computations based on GAAP contained in the indenture will be computed in conformity with GAAP.

Government Securities means direct obligations of, or obligations guaranteed by, the United States of America, and the payment for which the United States pledges its full faith and credit.

Guarantee means a guarantee other than by endorsement of negotiable instruments for collection in the ordinary course of business, direct or indirect, in any manner including, without limitation, by way of a pledge of assets or through letters of credit or reimbursement agreements in respect thereof, of all or any part of any Indebtedness (whether arising by virtue of partnership arrangements, or by agreements to keep-well, to purchase assets, goods, securities or services or to take or pay or to maintain financial statement conditions or otherwise), or entered into for purposes of assuring in any other manner the obligee of such Indebtedness of the payment thereof or to protect such obligee against loss in respect thereof (in whole or in part).

Hedging Obligations of any Person means the obligations of such Person pursuant to any Interest Rate and Currency Hedges and any Oil and Natural Gas Hedging Contracts.

Hydrocarbons means oil, gas, casinghead gas, drip gasoline, natural gasoline, condensate, distillate, liquid hydrocarbons, gaseous hydrocarbons and all constituents, elements or compounds thereof and products refined or processed therefrom.

Indebtedness means, with respect to any specified Person, without duplication, any indebtedness of such Person, regardless of whether contingent:

(1) in respect of borrowed money;

(2) evidenced by bonds, notes, debentures or similar instruments or letters of credit (or reimbursement agreements in respect thereof);

(3) in respect of banker s acceptances;

(4) representing Capital Lease Obligations;

(5) in respect of any Guarantee by such Person of production or payment with respect to a Production Payment (but not any other contractual obligation in respect of such Production Payment);

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(6) representing the balance deferred and unpaid of the purchase price of any property or services due more than six months after such property is acquired or such services are completed, except any such balance that constitutes an accrued expense or a trade payable; or

(7) representing any Interest Rate and Currency Hedges,

if and to the extent any of the preceding items (other than letters of credit and Interest Rate and Currency Hedges) would appear as a liability upon a balance sheet of the specified Person prepared in accordance with GAAP. In addition, the term *Indebtedness* includes (a) all Indebtedness of any other Person, of the types described above in clauses (1) through (7), secured by a Lien on any asset of the specified Person (regardless of whether such Indebtedness is assumed by the specified Person), *provided* that the amount of such Indebtedness will be the lesser of (i) the Fair Market Value of such asset at such date of determination and (ii) the amount of such Indebtedness of such other Person, and (b) to the extent not otherwise included, the Guarantee by the specified Person of any Indebtedness of any other Person, of the types described above in clauses (1) through (7). Furthermore, the amount of any Indebtedness outstanding as of any date will be the accreted value thereof, in the case of any Indebtedness issued with original issue discount; and the principal amount thereof, together with any interest thereon that is more than 30 days past due, in the case of any other Indebtedness.

Notwithstanding the foregoing, the following shall not constitute *Indebtedness*:

(i) accrued expenses and trade accounts payable arising in the ordinary course of business;

(ii) except as provided in clause (5) of the first paragraph of this definition, any obligation in respect of any Production Payment and Reserve Sales;

(iii) any obligation in respect of any Farm-In Agreement;

(iv) any indebtedness which has been defeased in accordance with GAAP or defeased pursuant to the deposit of cash or Government Securities (in an amount sufficient to satisfy all such indebtedness obligations at maturity or redemption, as applicable, and all payments of interest and premium, if any) in a trust or account created or pledged for the sole benefit of the holders of such indebtedness, and subject to no other Liens, and the other applicable terms of the instrument governing such indebtedness;

(v) oil or natural gas balancing liabilities incurred in the ordinary course of business and consistent with past practice;

(vi) any obligation in respect of any Oil and Natural Gas Hedging Contract;

(vii) any unrealized losses or charges in respect of Hedging Obligations (including those resulting from the application of FAS 133);

(viii) any obligations in respect of (a) bid, performance, completion, surety, appeal and similar bonds, (b) obligations in respect of bankers acceptances, (c) insurance obligations or bonds and other similar bonds and obligations and (d) any guaranties or letters of credit functioning as or supporting any of the foregoing bonds or obligations; *provided*, *however* that such bonds or obligations mentioned in subclause (a), (b), (c) or (d) of this clause (viii), are incurred in the ordinary course of the business of PDC and its Restricted Subsidiaries and do not relate to obligations for borrowed money;

(ix) any obligations in respect of completion bonds, performance bonds, bid bonds, appeal bonds, surety bonds, bankers acceptances, letters of credit, insurance obligations or bonds and other similar bonds and obligations incurred by PDC or any Restricted Subsidiary in the ordinary course of business and any guaranties and obligations of PDC or any Restricted Subsidiary with respect to or letters of credit functioning as or supporting any of the foregoing bonds or obligations;

(x) any obligation arising from any agreement providing for indemnities, guarantees, purchase price adjustments, holdbacks, contingency payment obligations based on the performance of the acquired or disposed assets or similar obligations (other than guaranties of Indebtedness) incurred by any Person in connection with the acquisition or disposition of assets; and

(xi) all contracts and other obligations, agreements instruments or arrangements described in clauses (20), (21), (22) and (23) of the definition of *Permitted Liens*.

Interest Rate Agreement means with respect to any Person any interest rate protection agreement, interest rate future agreement, interest rate option agreement, interest rate swap agreement, interest rate cap agreement, interest rate collar agreement, interest rate hedge agreement or other similar agreement or arrangement as to which such Person is party or a beneficiary.

Interest Rate and Currency Hedges of any Person means the obligations of such Person pursuant to any Interest Rate Agreement or Currency Agreement.

Investments means, with respect to any Person, all direct or indirect investments by such Person in other Persons (including Affiliates) in the forms of loans (including Guarantees or other obligations, advances or capital contributions (excluding endorsements of negotiable instruments and documents in the ordinary course of business, and commission, travel and similar advances to officers, employees and consultants made in the ordinary course of business), purchases or other acquisitions for consideration of Indebtedness, Equity Interests or other securities, together with all items that are or would be classified as investments on a balance sheet prepared in accordance with GAAP. If PDC or any Restricted Subsidiary sells or otherwise disposes of any Equity Interests of any direct or indirect Restricted Subsidiary such that, after giving effect to any such sale or disposition, such Person is no longer a Restricted Subsidiary, PDC will be deemed to have made an Investment on the date of any such sale or disposition equal to the Fair Market Value of PDC s Investments in such Restricted Subsidiary that were not sold or disposed of in an amount determined as provided in the final paragraph of the covenant described above under the caption Covenants Restricted Payments. The acquisition by PDC or any Subsidiary of PDC of a Person that holds an Investment in a third Person will be deemed to be an Investment by PDC or such Subsidiary in such third Person in an amount equal to the Fair Market Value of the Investments held by the acquired Person in such third Person in an amount determined as provided in the final paragraph of the covenant described above under the caption Covenants Restricted Payments. Except as otherwise provided in the indenture, the amount of an Investment will be determined at the time the Investment is made and without giving effect to subsequent changes in value.

Issue Date means February 8, 2008 (the first date on which old notes were issued under the indenture).

Legal Holiday means a Saturday, a Sunday or a day on which banking institutions in the City of New York or at a place of payment are authorized by law, regulation or executive order to remain closed.

Leverage Ratio means, with respect to any Person as of any date of determination, the ratio of (x) the total consolidated Indebtedness of such Person and its Restricted Subsidiaries as of the end of the most recent fiscal quarter for which internal financial statements are available, which would be reflected as a liability on a consolidated balance sheet of such Person and its Restricted Subsidiaries prepared as of such date in accordance with GAAP, to (y) the aggregate amount of Consolidated Cash Flow of such Person for the then most recent four fiscal quarters for which internal financial statements are available, in each case with such pro forma adjustments to the amount of consolidated Indebtedness and Consolidated Cash Flow as are appropriate and consistent with the pro forma adjustment provisions set forth in the definition of Fixed Charge Coverage Ratio.

Lien means, with respect to any asset, any mortgage, lien, pledge, charge, security interest or encumbrance of any kind in respect of such asset, regardless of whether filed, recorded or otherwise perfected under applicable law, including any conditional sale or other title retention agreement, any lease in the nature thereof, any option or other agreement to sell or give a security interest in and any filing of or agreement to give any financing statement under the Uniform Commercial Code (or equivalent statutes) of any jurisdiction.

Liquidated Damages means all Liquidated Damages then owning pursuant to the Registration Rights Agreement.

Master Limited Partnership means a limited liability company or partnership that is an Unrestricted Subsidiary and whose Capital Stock is traded on a stock exchange or over-the-counter market.

Material Subsidiary means any Domestic Restricted Subsidiary having Consolidated Tangible Assets that constitutes more than 10% of PDC s Consolidated Tangible Assets.

Moody s means Moody s Investors Service, Inc. or any successor to the rating agency business thereof.

Net Income means, with respect to any specified Person, the net income (loss) of such Person, determined in accordance with GAAP and before any reduction in respect of preferred stock dividends, excluding, however:

(1) any gain or loss, together with any related provision for taxes on such gain or loss, realized in connection with: (a) any Asset Sale or (b) the disposition of any securities by such Person or any of its Restricted Subsidiaries or the extinguishment of any Indebtedness of such Person or any of its Restricted Subsidiaries; and

(2) any extraordinary or nonrecurring gain or loss, together with any related provision for taxes on such extraordinary or nonrecurring gain or loss.

Net Proceeds means the aggregate cash proceeds received by PDC or any of its Restricted Subsidiaries in respect of any Asset Sale (including, without limitation, any cash received upon the sale or other disposition of any non-cash consideration received in any Asset Sale), net of:

(1) all legal, accounting, investment banking, title and recording tax expenses, commissions and other fees and expense incurred, and all federal, state, provincial, foreign and local taxes required to be paid or accrued as a liability under GAAP (after taking into account any available tax credits or deductions and any tax sharing agreements), as a consequence of such Asset Sale;

(2) all payments made on any Indebtedness which is secured by any assets subject to such Asset Sale, in accordance with the terms of such Indebtedness, or which must by its terms, or in order to obtain a necessary consent to such Asset Sale, or by applicable law be repaid out of the proceeds from such Asset Sale;

(3) all distributions and other payments required to be made to holders of minority interests in Subsidiaries or joint ventures as a result of such Asset Sale; and

(4) the deduction of appropriate amounts to be provided by the seller as a reserve, in accordance with GAAP, or held in escrow, in either case for adjustment in respect of the sale price or for any liabilities associated with the assets disposed of in such Asset Sale and retained by PDC or any Restricted Subsidiary after such Asset Sale.

Net Working Capital means (a) all current assets of PDC and its Restricted Subsidiaries except current assets from Oil and Natural Gas Hedging Contracts, less (b) all current liabilities of PDC and its Restricted Subsidiaries, except current liabilities included in Indebtedness and any current liabilities from Oil and Natural Gas Hedging Contracts, in each case as set forth in the consolidated financial statements of PDC prepared in accordance with GAAP (excluding any adjustments made pursuant to FAS 133).

Non-Recourse Debt means Indebtedness:

(1) as to which neither PDC nor any Restricted Subsidiary (a) provides any Guarantee or credit support of any kind (including any undertaking, Guarantee, indemnity, agreement or instrument that would constitute Indebtedness) or (b) is directly or indirectly liable (as a guarantor or otherwise), in each case other than Liens on and pledges of the Equity Interests of any Unrestricted Subsidiary or any joint venture owned by PDC or any Restricted Subsidiary to the extent securing otherwise Non-Recourse Debt of such Unrestricted Subsidiary or joint venture; and

(2) no default with respect to which (including any rights that the holders thereof may have to take enforcement action against an Unrestricted Subsidiary) would permit (upon notice, lapse of time or both) any holder of any other Indebtedness of PDC or any Restricted Subsidiary to declare a default under such other Indebtedness or cause the payment thereof to be accelerated or payable prior to its Stated Maturity.

Obligations means any principal, interest, penalties, fees, indemnifications, reimbursements, damages and other liabilities payable under the documentation governing any Indebtedness.

Officer means, in the case of PDC, the Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, the Treasurer or the Secretary of PDC and, in the case of any Subsidiary Guarantor, the Chairman of the Board, the Chief Executive Officer, the President, the Chief Financial Officer, any Vice President, the Treasurer or the Secretary of such Subsidiary Guarantor.

Officers Certificate means, in the case of PDC, a certificate signed by two Officers or by an Officer and either an Assistant Treasurer or an Assistant Secretary of PDC and, in the case of any Subsidiary Guarantor, a certificate signed by two Officers or by an Officer and either an Assistant Treasurer or an Assistant Secretary of such Subsidiary Guarantor.

Oil and Gas Properties means all Properties, including equity or other ownership interests therein, owned by such Person which contain proved oil and gas reserves as defined in Rule 4-10 of Regulation S-X of the Securities Act.

Oil and Natural Gas Hedging Contract means any oil and natural gas hedging agreements and other agreements or arrangements entered into in the ordinary course of business in the oil and gas industry for the purpose of protecting against fluctuations in oil or natural gas prices.

Parent means any entity that becomes the holder of 100% of the outstanding Equity Interests of PDC in a transaction in which the Beneficial Owners of PDC immediately prior to such transaction are Beneficial Owners in the same proportion of PDC immediately after such transaction.

Permitted Acquisition Indebtedness means Indebtedness or Disqualified Stock of PDC or any of PDC s Restricted Subsidiaries to the extent such Indebtedness or Disqualified Stock was Indebtedness or Disqualified Stock of:

(1) a Subsidiary prior to the date on which such Subsidiary became a Restricted Subsidiary; or

(2) a Person that was merged or consolidated into PDC or a Restricted Subsidiary,

provided that on the date such Subsidiary became a Restricted Subsidiary or the date such Person was merged and consolidated into PDC or a Restricted Subsidiary, as applicable, after giving pro forma effect thereto:

(a) the Restricted Subsidiary or PDC, as applicable, would be permitted to incur at least $1.00 of additional Indebtedness pursuant to the Fixed Charge Coverage Ratio test described under Covenants Incurrence of Indebtedness and Issuance of Preferred Stock, or

(b) the Fixed Charge Coverage Ratio for the Restricted Subsidiary or PDC, as applicable, would be greater than the Fixed Charge Coverage Ratio for such Restricted Subsidiary or PDC immediately prior to such transaction.

Permitted Business Investments means Investments and expenditures made in the ordinary course of, and of a nature that is or shall have become customary in, a Related Business as means of actively exploiting, exploring for, acquiring, developing, processing, gathering, marketing or transporting oil, natural gas, other hydrocarbons and minerals (including with respect to plugging and abandonment) through agreements, transactions, interests or arrangements that permit one to share risks or costs, comply with regulatory requirements regarding local ownership or satisfy other objectives customarily achieved through the conduct of a Related Business jointly with third parties, including without limitation, (i) ownership interests in oil, natural gas, other hydrocarbons and minerals properties or gathering, transportation, processing, storage or related systems and (ii) any operating agreements, joint ventures, partnership agreements, working interests, royalty interests, mineral leases, processing agreements, Farm-In Agreements, Farm-Out Agreements, contracts for the sale, transportation or exchange of oil, natural gas and other hydrocarbons, unitization agreements, pooling arrangements, joint bidding agreements, service contracts, partnership agreements, limited liability company agreements, subscription agreements, stock purchase agreements, stockholder agreements, area of mutual interest agreements, production sharing agreements or other similar or customary agreements, transactions, properties, interests, or arrangements, and Investments and expenditures in connection therewith or pursuant thereto. Notwithstanding the foregoing, Permitted Business Investments shall not include Investments in a Master Limited Partnership.

Permitted Investments means:

(1) any Investment in PDC or in a Restricted Subsidiary;

(2) any Investment in Cash Equivalents;

(3) any Investment by PDC or any Restricted Subsidiary in a Person, if as a result of such Investment:

(a) such Person becomes a Restricted Subsidiary; or

(b) such Person is merged or consolidated with or into, or transfers or conveys substantially all of its assets to, or is liquidated into, PDC or a Restricted Subsidiary;

(4) any Investment made as a result of the receipt of non-cash consideration from an Asset Sale that was made pursuant to and in compliance with the covenant described above under the caption Repurchase at the Option of Holders Asset Sales;

(5) any Investments received in compromise or resolution of (a) obligations of trade creditors or customers that were incurred in the ordinary course of business of PDC or any of its Restricted Subsidiaries, including pursuant to any plan of reorganization or similar arrangement upon the bankruptcy or insolvency of any trade creditor or customer; or (b) litigation, arbitration or other disputes with Persons who are not Affiliates;

(6) Investments represented by Hedging Obligations;

(7) advances to or reimbursements of employees for moving, entertainment and travel expenses, drawing accounts and similar expenditures in the ordinary course of business;

(8) loans or advances to employees in the ordinary course of business or consistent with past practice;

(9) advances and prepayments for asset purchases in the ordinary course of business in a Related Business of PDC or any of its Restricted Subsidiaries;

(10) receivables owing to PDC or any Restricted Subsidiary created or acquired in the ordinary course of business and payable or dischargeable in accordance with customary trade terms; provided, however, that such trade terms may include such concessionary trade terms as PDC or any such Restricted Subsidiary deems reasonable under the circumstances;

(11) surety and performance bonds and workers compensation, utility, lease, tax, performance and similar deposits and prepaid expenses in the ordinary course of business;

(12) guarantees by PDC or any of its Restricted Subsidiaries of operating leases (other than Capital Lease Obligations) or of other obligations that do not constitute Indebtedness, in each case entered into by PDC or any such Restricted Subsidiary in the ordinary course of business;

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(13) Investments of a Restricted Subsidiary acquired after the Issue Date or of any entity merged into PDC or merged into or consolidated with a Restricted Subsidiary in accordance with the covenant described under Covenants Merger, Consolidation or Sale of Substantially All Assets or the covenant described in the third paragraph under Subsidiary Guarantees of the Notes (as applicable) to the extent that such Investments were not made in contemplation of or in connection with such acquisition, merger or consolidation and were in existence on the date of such acquisition, merger or consolidation;

(14) Permitted Business Investments;

(15) Investments in a Master Limited Partnership received in consideration for contributions made by PDC or any of its Restricted Subsidiaries from time to time to such Master Limited Partnership of properties and assets that are used or useful in a Related Business; provided that, with respect to each such contribution (i) PDC or the applicable Restricted Subsidiary receives consideration with a Fair Market Value at the time of such contribution at least equal to the Fair Market Value of the properties and assets contributed and (ii) after giving pro forma effect thereto and to any related financing transactions as if each had occurred at the beginning of PDC s most recently ended four full fiscal quarters for which internal financial statements are available, PDC s Leverage Ratio would not have exceeded 2.5 to 1;

(16) Investments received as a result of a foreclosure by PDC or any of its Restricted Subsidiaries with respect to any secured Investment in default;

(17) Investments in any units of any oil and gas royalty trust;

(18) Investments existing on the Issue Date, and any extension, modification or renewal of any such Investments existing on the Issue Date, but only to the extent not involving additional advances, contributions or other Investments of cash or other assets or other increases of such Investments (other than as a result of the accrual or accretion of interest or original issue discount or the issuance of pay-in-kind securities, in each case, pursuant to the terms of such Investments as in effect on the Issue Date);

(19) repurchases of or other Investments in the notes; and

(20) other Investments in any Person having an aggregate Fair Market Value (measured on the date each such Investment was made and without giving effect to subsequent changes in value), when taken together with all other Investments made pursuant to this clause (20) that are at the time outstanding not to exceed the greater of (a) 3.0% of Adjusted Consolidated Net Tangible Assets or (b) $25.0 million.

Permitted Liens means, with respect to any Person:

(1) Liens securing Indebtedness incurred under Credit Facilities pursuant to the covenant described under the caption Covenants Incurrence of Indebtedness and Issuance of Preferred Stock;

(2) Liens to secure Indebtedness (including Capital Lease Obligations) permitted by clause (4) of the second paragraph of the covenant entitled Covenants Incurrence of Indebtedness and Issuance of Preferred Stock covering only the assets acquired with or financed by such Indebtedness;

(3) pledges or deposits by such Person under workmen s compensation laws, unemployment insurance laws or similar legislation, or good faith deposits in connection with bids, tenders, contracts (other than for the payment of Indebtedness) or leases to which such Person is a party, or deposits to secure public or statutory obligations of such Person or deposits or cash or United States government bonds to secure surety or appeal bonds to which such Person is a party, or deposits as security for contested taxes or import or customs duties or for the payment of rent, in each case incurred in the ordinary course of business;

(4) landlords , carriers , warehousemen s, mechanics , materialmen s, repairmen s or similar Liens arising by contract or statute in the ordinary course of business and with respect to amounts which are not yet delinquent or are being contested in good faith by appropriate proceedings;

(5) Liens for taxes, assessments or other governmental charges or which are being contested in good faith by appropriate proceedings provided appropriate reserves required pursuant to GAAP have been made in respect thereof;

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(6) Liens in favor of the issuers of surety or performance bonds or letters of credit or bankers acceptances issued pursuant to the request of and for the account of such Person in the ordinary course of its business; provided, however, that such letters of credit do not constitute Indebtedness;

(7) encumbrances, easements or reservations of, or rights of others for, licenses, rights of way, sewers, electric lines, telegraph and telephone lines and other similar purposes, or zoning or other restrictions as to the use of real properties or Liens incidental to the conduct of the business of such Person or to the ownership of its properties which do not in the aggregate materially adversely affect the value of said properties or materially impair their use in the operation of the business of such Person;

(8) leases and subleases of real property which do not materially interfere with the ordinary conduct of the business of PDC and its Restricted Subsidiaries, taken as a whole;

(9) any attachment or judgment Liens not giving rise to an Event of Default;

(10) Liens for the purpose of securing the payment of all or a part of the purchase price of, or Capital Lease Obligations with respect to, or the repair, improvement or construction cost of, assets or property acquired or repaired, improved or constructed in the ordinary course of business; provided that:

(a) the aggregate principal amount of Indebtedness secured by such Liens is otherwise permitted to be incurred under the indenture and does not exceed the cost of the assets or property so acquired or repaired, improved or constructed plus fees and expenses in connection therewith; and

(b) such Liens are created within 180 days of repair, improvement or construction or acquisition of such assets or property and do not encumber any other assets or property of PDC or any Restricted Subsidiary other than such assets or property and assets affixed or appurtenant thereto (including improvements);

(11) Liens arising solely by virtue of any statutory or common law provisions relating to banker s Liens, rights of set-off or similar rights and remedies as to deposit accounts or other funds maintained or deposited with a depositary institution; provided that:

(a) such deposit account is not a dedicated cash collateral account and is not subject to restrictions against access by PDC in excess of those set forth by regulations promulgated by the Federal Reserve Board; and

(b) such deposit account is not intended by PDC or any Restricted Subsidiary to provide collateral to the depository institution;

(12) Liens arising from Uniform Commercial Code financing statement filings regarding operating leases entered into by PDC and its Restricted Subsidiaries in the ordinary course of business;

(13) Liens existing on the Issue Date;

(14) Liens on property at the time PDC or a Restricted Subsidiary acquired the property, including any acquisition by means of a merger or consolidation with or into PDC or a Restricted Subsidiary; provided, however, that such Liens are not created, incurred or assumed in connection with, or in contemplation of, such acquisition; provided further, however, that such Liens may not extend to any other property owned by PDC or any Restricted Subsidiary other than those of the Person merged or consolidated with PDC or such Restricted Subsidiary;

(15) Liens on property or shares of stock of a Person at the time such Person becomes a Restricted Subsidiary; provided, however, that such Liens are not created, incurred or assumed in connection with, or in contemplation of, such other Person becoming a Restricted Subsidiary; provided further, however, that such Liens may not extend to any other property owned by PDC or any Restricted Subsidiary;

(16) Liens securing Indebtedness or other obligations of a Restricted Subsidiary owing to PDC or a Subsidiary Guarantor;

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(17) Liens securing the notes, the Subsidiary Guarantees and other obligations arising under the indenture;

(18) Liens securing Permitted Refinancing Indebtedness of PDC or a Restricted Subsidiary incurred to refinance Indebtedness of PDC or a Restricted Subsidiary that was previously so secured; provided that any such Lien is limited to all or part of the same property or assets (plus improvements, accessions, proceeds or dividends or distributions in respect thereof) that secured (or, under the written arrangements under which the original Lien arose, could secure) the Indebtedness being refinanced or is in respect of property or assets that is the security for a Permitted Lien hereunder;

(19) Liens in respect of Production Payments and Reserve Sales;

(20) Liens on pipelines and pipeline facilities that arise by operation of law;

(21) Liens arising under joint venture agreements, partnership agreements, oil and gas leases or subleases, assignments, purchase and sale agreements, division orders, contracts for the sale, purchasing, processing, transportation or exchange of oil or natural gas, unitization and pooling declarations and agreements, development agreements, area of mutual interest agreements, licenses, sublicenses, net profits interests, participation agreements, Farm-Out Agreements, Farm-In Agreements, carried working interest, joint operating, unitization, royalty, sales and similar agreements relating to the exploration or development of, or production from, Oil and Gas Properties entered into in the ordinary course of business in a Related Business;

(22) Liens reserved in oil and gas mineral leases for bonus, royalty or rental payments and for compliance with the terms of such leases;

(23) Liens on, or related to, properties or assets to secure all or part of the costs incurred in the ordinary course of a Related Business for exploration, drilling, development, production, processing, transportation, marketing, storage, abandonment or operation;

(24) Liens arising under the indenture in favor of the trustee for its own benefit and similar Liens in favor of other trustees, agents and representatives arising under instruments governing Indebtedness permitted to be incurred under the indenture, provided that such Liens are solely for the benefit of the trustees, agents or representatives in their capacities as such and not for the benefit of the holders of the Indebtedness;

(25) Liens securing obligations of PDC and its Restricted Subsidiaries under non-speculative Hedging Obligations;

(26) Liens on and pledges of the Equity Interests of any Unrestricted Subsidiary or any joint venture owned by PDC or any Restricted Subsidiary to the extent securing Non-Recourse Debt of such Unrestricted Subsidiary or joint venture;

(27) Liens securing Indebtedness of any Foreign Subsidiary which Indebtedness is permitted by the indenture; and

(28) Liens incurred in the ordinary course of business of PDC or any Restricted Subsidiary with respect to obligations that, at any one time outstanding, do not exceed the greater of $25.0 million and 3.0% of Adjusted Consolidated Net Tangible Assets.

Permitted Payments to Parent means, for so long as PDC is a member of a group filing a consolidated or combined tax return with the Parent, payments to the Parent in respect of an allocable portion of the tax liabilities of such group that is attributable to PDC and its Subsidiaries (Tax Payments). The Tax Payments shall not exceed the lesser of (a) the amount of the relevant tax (including any penalties and interest) that PDC would owe if PDC were filing a separate tax return (or a separate consolidated or combined return with its Subsidiaries that are members of the consolidated or combined group), taking into account any carryovers and carrybacks of tax attributes (such as net operating losses) of PDC and such Subsidiaries from other taxable years and (b) the net amount of the relevant tax that the Parent actually owes to the appropriate taxing authority. Any Tax Payments received from PDC shall be paid to the appropriate taxing authority within 30 days of the Parent s receipt of such Tax Payments or refunded to PDC.

Permitted Refinancing Indebtedness means any Indebtedness of PDC or any of its Restricted Subsidiaries, any Disqualified Stock of PDC or any preferred stock of any Restricted Subsidiary (a) issued in exchange for, or the net proceeds of which are used to extend, renew, refund, refinance, replace, defease, discharge or otherwise retire for value, in whole or in part, or (b) constituting an amendment, modification or supplement to or a deferral or renewal of ((a) and (b) above, collectively, a Refinancing), any other Indebtedness of PDC any of its Restricted Subsidiaries (other than intercompany Indebtedness), any Disqualified Stock of PDC or any preferred stock of a Restricted Subsidiary in a principal amount or, in the case of Disqualified Stock of PDC or preferred stock of a Restricted Subsidiary, liquidation preference, not to exceed (after deduction of reasonable and customary fees and expenses incurred in connection with the Refinancing) the lesser of:

(1) the principal amount or, in the case of Disqualified Stock or preferred stock, liquidation preference, of the Indebtedness, Disqualified Stock or preferred stock so Refinanced (plus, in the case of Indebtedness, the amount of premium, if any paid in connection therewith), and

(2) if the Indebtedness being Refinanced was issued with any original issue discount, the accreted value of such Indebtedness (as determined in accordance with GAAP) at the time of such Refinancing.

Notwithstanding the preceding, no Indebtedness, Disqualified Stock or preferred stock will be deemed to be Permitted Refinancing Indebtedness, unless:

(1) such Indebtedness, Disqualified Stock or preferred stock has a final maturity date or redemption date, as applicable, later than the final maturity date or redemption date, as applicable, of, and has a Weighted Average Life to Maturity equal to or greater than the Weighted Average Life to Maturity of, the Indebtedness, Disqualified Stock or preferred stock being Refinanced;

(2) if the Indebtedness, Disqualified Stock or preferred stock being Refinanced is contractually subordinated or otherwise junior in right of payment to the notes, such Indebtedness, Disqualified Stock or preferred stock has a final maturity date or redemption date, as applicable, later than the final maturity date or redemption date, as applicable, of, and is contractually subordinated or otherwise junior in right of payment to, the notes, on terms at least as favorable to the holders of notes as those contained in the documentation governing the Indebtedness, Disqualified Stock or preferred stock being Refinanced at the time of the Refinancing; and

(3) such Indebtedness or Disqualified Stock is incurred or issued by PDC or such Indebtedness, Disqualified Stock or preferred stock is incurred or issued by the Restricted Subsidiary who is the obligor on the Indebtedness being Refinanced or the issuer of the Disqualified Stock or preferred stock being Refinanced; provided that a Restricted Subsidiary that is also a Subsidiary Guarantor may guarantee Permitted Refinancing Indebtedness incurred by PDC, regardless of whether such Restricted Subsidiary was an obligor or guarantor of the Indebtedness being renewed, refunded, refinanced, replaced, defeased or discharged.

Person means any individual, corporation, partnership, joint venture, association, joint-stock company, trust, unincorporated organization, limited liability company, government or any agency or political subdivision thereof or any other entity.

Principal Property means any asset or property owned or leased by PDC or any Subsidiary of PDC, the gross book value of which exceeds 1% of the Consolidated Net Worth of PDC.

Production Payments means Dollar-Denominated Production Payments and Volumetric Production Payments, collectively.

Production Payments and Reserve Sales means the grant or transfer by PDC or a Subsidiary of PDC to any Person of a royalty, overriding royalty, net profits interest, Production Payment, partnership or other interest in Oil and Gas Properties, reserves or the right to receive all or a portion of the production or the proceeds from the sale of production attributable to such properties, including any such grants or transfers pursuant to incentive compensation programs on terms that are reasonably customary in the oil and gas business for geologists, geophysicists and other providers of technical services to PDC or a Subsidiary of PDC.

Registration Rights Agreement means that certain registration rights agreement dated as of the Issue Date by and among PDC and the initial purchasers set forth therein.

Related Business means any business which is the same as or related, ancillary or complementary to any of the businesses of PDC and its Restricted Subsidiaries on the Issue Date, which includes (1) the acquisition, exploration, exploitation, development, production, operation and disposition of interests in oil, gas and other hydrocarbon properties, and the utilization of PDC s and its Restricted Subsidiaries properties, (2) the gathering, marketing, treating, processing, storage, refining, selling and transporting of any production from such interests or properties and products produced in association therewith, (3) any power generation and electrical transmission business, (4) oil field sales and services and related activities, (5) development, purchase and sale of real estate and interests therein, and (6) any business or activity relating to, arising from, or necessary, appropriate or incidental to the activities described in the foregoing clauses (1) through (5) of this definition.

Restricted Investment means any Investment other than a Permitted Investment.

Restricted Subsidiary means any Subsidiary of PDC other than an Unrestricted Subsidiary.

S&P means Standard & Poor s Ratings Services, a division of The McGraw-Hill Companies, Inc.

SEC means the Securities and Exchange Commission.

Securities Act means the Securities Act of 1933, as amended.

Senior Credit Agreement means, with the Credit Agreement, dated as of November 4, 2005, among PDC, JPMorgan Chase Bank, N.A., as administrative agent, and the lenders and agents parties thereto from time to time and any related notes, Guarantees, collateral documents, instruments and agreements executed in connection therewith, and in each case as amended, restated, modified, supplemented, increased, renewed, refunded, replaced (including replacement after the termination of such credit facility), supplemented, restructured or refinanced in whole or in part from time to time in one or more agreements or instruments.

Senior Debt means:

(1) all Indebtedness of PDC or any of its Restricted Subsidiaries outstanding under Credit Facilities and all Hedging Obligations with respect thereto;

(2) any other Indebtedness of PDC or any of its Restricted Subsidiaries permitted to be incurred under the terms of the indenture, unless the instrument under which such Indebtedness is incurred expressly provides that it is subordinated in right of payment to the notes or any Subsidiary Guarantee; and

(3) all Obligations with respect to the items listed in the preceding clauses (1) and (2).

Notwithstanding anything to the contrary in the preceding sentence, Senior Debt will not include:

(a) any intercompany Indebtedness of PDC or any of its Subsidiaries to PDC or any of its Affiliates;

(b) any Indebtedness that is incurred in violation of the indenture; or

(c) any trade payables or taxes owed or owing by PDC or any Restricted Subsidiary.

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Senior Net Leverage Ratio means, with respect to any Person as of any date of determination, the ratio of (x) the total consolidated Senior Debt of such Person and its Restricted Subsidiaries as of the end of the most recent fiscal quarter for which internal financial statements are available, which would be reflected as a liability on a consolidated balance sheet of such Person and its Restricted Subsidiaries prepared as of such date in accordance with GAAP less the amount of cash of such Person and its Restricted Subsidiaries as of the end of such fiscal quarter which would be reflected on a consolidated balance sheet of such Person and its Restricted Subsidiaries prepared as of such date in accordance with GAAP, to (y) the aggregate amount of Consolidated Cash Flow of such Person for the then most recent four fiscal quarters for which internal financial statements are available, in each case with such pro forma adjustments to the amount of consolidated Indebtedness and Consolidated Cash Flow as are appropriate and consistent with the pro forma adjustment provisions set forth in the definition of Fixed Charge Coverage Ratio.

Significant Subsidiary means any Restricted Subsidiary that would be a significant subsidiary of PDC within the meaning of Rule 1-02 under Regulation S-X under the Securities Act.

Stated Maturity means, with respect to any installment of interest or principal on any series of Indebtedness, the date on which the payment of interest or principal was scheduled to be paid in the documentation governing such Indebtedness as of the Issue Date, and will not include any contingent obligations to repay, redeem or repurchase any such interest or principal prior to the date originally scheduled for the payment thereof.

Subordinated Debt means Indebtedness of PDC or a Subsidiary Guarantor that is contractually subordinated in right of payment (by its terms or the terms of any document or instrument relating thereto), to the notes or the Subsidiary Guarantee of such Subsidiary Guarantor, as applicable.

Subsidiary means, with respect to any specified Person:

(1) any corporation, association or other business entity of which more than 50% of the total voting power of shares of Capital Stock entitled (without regard to the occurrence of any contingency and after giving effect to any voting agreement or stockholders agreement that effectively transfers voting power) to vote in the election of directors, managers or trustees of the corporation, association or other business entity is at the time owned or controlled, directly or indirectly, by that Person or one or more of the other Subsidiaries of that Person (or a combination thereof); and

(2) any partnership (a) the sole general partner or the managing general partner of which is such Person or a Subsidiary of such Person or (b) the only general partners of which are that Person or one or more Subsidiaries of that Person (or any combination thereof).

Subsidiary Guarantee means any Guarantee of the notes by any Subsidiary Guarantor in accordance with the provisions of the indenture described under the caption Covenants Subsidiary Guarantees.

Subsidiary Guarantor means each Restricted Subsidiary that has become obligated under a Subsidiary Guarantee, in accordance with the terms of the guarantee provisions of the indenture, but only for so long as such Subsidiary remains so obligated pursuant to the terms of the indenture.

Unrestricted Subsidiary means any Subsidiary of PDC that is designated by the Board of Directors of PDC as an Unrestricted Subsidiary pursuant to a resolution of such Board of Directors, but only to the extent that such Subsidiary:

(1) has no Indebtedness other than Non-Recourse Debt;

(2) is a Person with respect to which neither PDC nor any of its Restricted Subsidiaries has any direct or indirect obligation (a) to subscribe for additional Equity Interests (if it is not a Master Limited Partnership) or (b) to maintain or preserve such Person s financial condition or to cause such Person to achieve any specified levels of operating results; and

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(3) has not guaranteed or otherwise directly or indirectly provided credit support for any Indebtedness of PDC or any of its Restricted Subsidiaries, except to the extent such Guarantee or credit support would be released upon such designation.

Volumetric Production Payments means production payment obligations recorded as deferred revenue in accordance with GAAP, together with all related undertakings and obligations.

Voting Stock of any specified Person as of any date means the Capital Stock of such Person that is at the time entitled to vote in the election of the Board of Directors of such Person.

Weighted Average Life to Maturity means, when applied to any Indebtedness at any date, the number of years obtained by dividing:

(1) the sum of the products obtained by multiplying (a) the amount of each then remaining installment, sinking fund, serial maturity or other required payments of principal, including payment at final maturity, in respect of the Indebtedness, by (b) the number of years (calculated to the nearest one-twelfth) that will elapse between such date and the making of such payment; by

(2) the then outstanding principal amount of such Indebtedness.

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MATERIAL UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following is a discussion of the material United States federal income tax considerations applicable to the exchange of old notes for new notes in the exchange offer and of owning and disposing of the notes. This discussion applies only to holders of the notes who hold the notes as capital assets within the meaning of Section 1221 of the Internal Revenue Code of 1986, as amended, which we refer to as the Code.

In this discussion, we do not purport to address all tax considerations that may be important to a particular holder in light of the holder s circumstances, or to certain categories of investors that may be subject to special rules, such as:

- dealers in securities or currencies;
- traders in securities;
- U.S. holders whose functional currency is not the U.S. dollar;
- persons holding notes as part of a hedge, straddle, conversion or other synthetic security or integrated transaction;
- certain U.S. expatriates; financial institutions; insurance companies;
- entities that are tax-exempt for U.S. federal income tax purposes; and
- partnerships and other pass-through entities.

This discussion does not address all of the aspects of U.S. federal income taxation that may be relevant to you in light of your particular investment or other circumstances. If a partnership or other entity treated as a partnership for U.S. federal income tax purposes holds notes, the tax treatment of a partner will generally depend on the status of the partner and on the activities of the partnership. We urge partners of partnerships holding notes to consult their tax advisors. In addition, this discussion does not address any state, local or foreign income or other tax consequences.

This discussion is based on U.S. federal income tax law, including the provisions of the Code, Treasury regulations, administrative rulings and judicial authority, all as in effect as of the date of this document. Subsequent developments in U.S. federal income tax law, including changes in law or differing interpretations, which may be applied retroactively, could have a material effect on the U.S. federal income tax consequences of owning and disposing of notes as described in this discussion.

We have not obtained and do not intend to obtain a ruling from the Internal Revenue Service, or IRS, with respect to the U.S. federal income taxation consequences of the exchange offer that may be applicable to your particular circumstances.

We urge you to consult your own tax advisor regarding the particular U.S. federal, state, local and foreign income and other tax consequences of the exchange offer and of owning and disposing of the notes that may be applicable to you.

The Exchange Offer

An exchange of old notes for new notes pursuant to the exchange offer will not be a taxable transaction for U.S. federal income tax purposes. Holders will not recognize any taxable gain or loss as a result of the exchange offer and will have the same tax basis and holding period in the new notes as they had in the old notes immediately before the exchange.

U.S. Holders

You are a U.S. holder for purposes of this discussion if you are a beneficial owner of notes that is for U.S. federal income tax purposes:

- a citizen or resident of the United States,

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- a corporation created or organized in or under the laws of the United States, any state thereof or the District of Columbia,
- an estate, the income of which is subject to U.S. federal income taxation regardless of the source of that income, or
- a trust, if, in general, a U.S. court is able to exercise primary supervision over the trust s administration and one or more U.S. persons are authorized to control all substantial decisions of the trust.

Payments of Interest

Generally, interest on the notes will be taxable as ordinary interest income at the time it is paid or accrues in accordance with your method of accounting for U.S. federal income tax purposes. Special rules governing the treatment of discount and premium are described below.

Discount and Premium

If you acquired a note at a discount, you may be subject to the market discount rules of the Code. These rules provide, in part, that gain on the sale or other disposition of a note and partial principal payments on a note are treated as ordinary income to the extent of accrued market discount. The market discount rules also provide for deferral of interest deductions with respect to debt incurred to purchase or carry a note that has market discount.

If you acquired a note at a premium over the sum of all amounts payable thereafter on the note that are treated as stated redemption price at maturity, within the meaning of the Code, you may elect to offset the premium against interest income over the remaining term of the note in accordance with the premium amortization provisions of the Code.

The rules concerning discounts and premiums are complex, and we urge you to consult your own tax advisor to determine how, and to what extent, any discount or premium will be included in your income or amortized, and as to the desirability, mechanics and consequences of making any elections in connection therewith in connection with your particular circumstances.

Sale or Other Disposition of Notes

When you sell or otherwise dispose of a note in a taxable transaction, you generally will recognize taxable gain or loss equal to the difference, if any, between your adjusted tax basis in the note and the amount realized on the sale or other disposition (which does not include for this purpose any amount attributable to accrued interest, which will be taxable in the manner described under U.S. Holders Payments of Interest).

Gain or loss realized on the sale or other disposition of a note will generally be capital gain or loss and will be long-term capital gain or loss if the note has been held for more than one year. You are urged to consult your own tax advisors regarding the treatment of capital gains, which may be taxed at lower rates than ordinary income for taxpayers who are individuals, and losses, the deductibility of which is subject to limitations.

Information Reporting and Backup Withholding

Information reporting requirements apply to interest and principal payments and to the proceeds of sales before maturity. These amounts generally must be reported to the IRS. In general, backup withholding (currently at a rate of 28%) may apply to any payments made to you of interest on your notes, and to payment of the proceeds of a sale or other disposition of your notes before maturity, if you are a non-corporate U.S. holder and fail to provide a correct taxpayer identification number, certified under penalties of perjury, or otherwise fail

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to comply with applicable requirements of the backup withholding rules. The backup withholding tax is not an additional tax and may be credited against your U.S. federal income tax liability if the required information is timely provided to the IRS.

Non-U.S. Holders

The following summary applies to you if you are a non-U.S. holder. You generally are a non-U.S. holder for purposes of this discussion if you are a beneficial owner (other than an entity treated as a partnership for U.S. federal income tax purposes) of notes that is not a U.S. holder, as described above.

Taxation of Interest

Under current U.S. federal income tax laws, and subject to the discussion below, U.S. federal withholding tax will not apply to payments of interest on the notes under the portfolio interest exception of the Code, *provided* that:

- you do not, directly or indirectly, actually or constructively, own 10% or more of the total combined voting power of all classes of our shares;
- you are not a controlled foreign corporation that is related to us within the meaning of the Code; and
- the U.S. payor does not have actual knowledge or reason to know that you are a U.S. person and either (1) you certify to the applicable payor or its agent, under penalties of perjury, that you are not a U.S. holder and provide your name and address on IRS Form W-8BEN (or a suitable substitute form) or (2) a securities clearing organization, bank or other financial institution, that holds customers securities in the ordinary course of its trade or business (a financial institution) and holds the note, certifies under penalties of perjury that a IRS Form W-8BEN (or a suitable substitute form) has been received from you by it or by a financial institution between it and you and furnishes the payor with a copy of the form or the U.S. payor otherwise possesses documentation upon which it may rely to treat the payment as made to a non-U.S. person in accordance with applicable U.S. Treasury regulations.

If you cannot satisfy the requirements described above, payments of interest made to you will be subject to the 30% U.S. federal withholding tax, unless you provide a properly executed IRS Form W-8BEN or successor form claiming an exemption from or a reduction of withholding under the benefit of a U.S. income tax treaty, or you provide a properly executed IRS Form W-8ECI claiming that the payments of interest are effectively connected with your conduct of a trade or business in the United States. If such interest is effectively connected with a U.S. trade or business, please read Non-U.S. Holders Income Effectively Connected with a U.S. Trade or Business.

Gain on Disposition of Notes

You generally will not be subject to U.S. federal income and withholding tax on gain realized on the sale, exchange, redemption or other taxable disposition of a note unless:

- you are an individual present in the United States for 183 days or more in the year of such sale, exchange, redemption or other taxable disposition and specific other conditions are present, or
- the gain is effectively connected with your conduct of a U.S. trade or business, and, if a U.S. income tax treaty applies, is generally attributable to a U.S. permanent establishment you maintain. Please read Non-U.S. Holders Income Effectively Connected with a U.S. Trade or Business.

Income Effectively Connected with a U.S. Trade or Business

If you are engaged in a trade or business in the United States and interest, gain or any other income in respect of your notes is effectively connected with the conduct of your trade or business, and, if a U.S. income

tax treaty applies, you maintain a U.S. permanent establishment to which the interest, gain or other income is generally attributable, you may be subject to U.S. income tax on a net income basis on such interest, gain or income. In this instance, however, the interest on your notes will be exempt from the 30% U.S. withholding tax discussed under the caption Non-U.S. Holders Taxation of Interest , if you provide a properly executed IRS Form W-8ECI or appropriate substitute form to the payor on or before any payment date to claim the exemption.

In addition, if you are a foreign corporation, you may be subject to a U.S. branch profits tax equal to 30% of your effectively connected earnings and profits for the taxable year, as adjusted for certain items, unless a lower rate applies to you under a U.S. income tax treaty with your country of residence. For this purpose, you must include interest, gain and income on your notes in the earnings and profits subject to the U.S. branch profits tax if these amounts are effectively connected with the conduct of your U.S. trade or business.

Information Reporting and Backup Withholding

Payments made to you of interest on the notes and amounts, if any, withheld from such payments will be reported to the IRS and to you. U.S. backup withholding tax generally will not apply to payments of interest and principal on the notes if you have provided the required certification that you are a non-U.S. holder as described in Non-U.S. Holders Taxation of Interest above or otherwise established an exemption, *provided* that the payor does not have actual knowledge or reason to know that you are a U.S. holder or that the conditions of any other exemptions are not in fact satisfied.

The gross proceeds from the disposition of your notes may be subject to information reporting and backup withholding tax. Payments of the proceeds of a sale of your notes effected through a U.S. office of a broker will be subject to both U.S. backup withholding and information reporting unless you provide an IRS Form W-8BEN certifying that you are a non-U.S. person and specific other conditions are met or you otherwise establish an exemption. If you sell your notes outside the United States through a non-U.S. office of a non-U.S. broker and the sales proceeds are paid to you outside the United States, then the U.S. backup withholding and information reporting requirements generally will not apply to that payment. However, U.S. information reporting, but not backup withholding, will apply to a payment of sales proceeds, even if that payment is made outside the United States, if you sell your notes through a non-U.S. office of a broker that:

- is a United States person as defined in the Code;
- derives 50% or more of its gross income in specific periods from the conduct of a trade or business in the United States;
- is a controlled foreign corporation for U.S. federal income tax purposes; or
- is a foreign partnership that, at any time during its taxable year, has more than 50% of its income or capital interests owned by U.S. persons or is engaged in the conduct of a U.S. trade or business, unless the broker has documentary evidence in its files that you are a non-U.S. person and specific other conditions are met or you otherwise establish an exemption.

We urge you to consult your own tax advisor regarding application of backup withholding in your particular circumstances and the availability of and procedure for obtaining an exemption from backup withholding under current Treasury regulations. Any amounts withheld under the backup withholding rules from a payment to you will be allowed as a refund or credit against your U.S. federal income tax liability, *provided* that the required information is furnished to the IRS.

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PLAN OF DISTRIBUTION

Based on interpretations by the staff of the SEC set forth in no action letters issued to third parties, we believe that you may transfer new notes issued under the exchange offer in exchange for old notes unless you are:

- our affiliate within the meaning of Rule 405 under the Securities Act;
- a broker-dealer that acquired old notes directly from us; or
- a broker-dealer that acquired old notes as a result of market-making or other trading activities without compliance with the registration and prospectus delivery provisions of the Securities Act;

provided that you acquire the new notes in the ordinary course of your business and you are not engaged in, and do not intend to engage in, and have no arrangement or understanding with any person to participate in, a distribution of the new notes. Broker-dealers receiving new notes in the exchange offer will be subject to a prospectus delivery requirement with respect to resales of the new notes.

To date, the staff of the SEC has taken the position that participating broker-dealers may fulfill their prospectus delivery requirements with respect to transactions involving an exchange of securities such as this exchange offer, other than a resale of an unsold allotment from the original sale of the old notes, with the prospectus contained in the exchange offer registration statement.

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. 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 as a result of market-making activities or other trading activities. In addition, until August 21, 2008, all dealers effecting transactions in the new notes may be required to deliver a prospectus.

We will not receive any proceeds from any sale of new notes by brokers-dealers or any other persons. New notes received by broker-dealers for their own account pursuant to the exchange offer may be sold from time to time in one or more transactions in the over-the-counter market, in negotiated transactions, through the writing of options on the new notes or a combination of such methods of resale, at market prices prevailing at the time of resale, at prices related to such prevailing market prices or negotiated prices. Any such resale may be made directly to purchasers or to or through brokers or dealers who may receive compensation in the form of commissions or concessions from any such broker-dealer and/or the purchasers of any such new notes. Any broker-dealer that resells new notes that were received by it for its own account pursuant to the exchange offer and any broker or dealer that participates in a distribution of such new notes may be deemed to be an underwriter within the meaning of the Securities Act and any profit of any such resale of new notes and any commissions or concessions received by any such persons may be deemed to be underwriting compensation under the Securities Act. The letter of transmittal states that by acknowledging that it will deliver 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.

We have agreed to pay all expenses incident to this exchange offer other than commissions or concessions of any brokers or dealers and will indemnify the holders of the old notes (including any broker-dealers) against certain liabilities, including liabilities under the Securities Act.

Each broker-dealer must acknowledge and agree that, upon receipt of notice from us of the happening of any event which makes any statement in the prospectus untrue in any material respect or which requires the making of any changes in the prospectus to make the statements in the prospectus not misleading, which notice we agree to deliver promptly to the broker-dealer, the broker-dealer will suspend use of the prospectus until we have notified the broker-dealer that delivery of the prospectus may resume and have furnished copies of any amendment or supplement to the prospectus to the broker-dealer.

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LEGAL MATTERS

The validity of the notes offered in the exchange offer will be passed upon for us by Andrews Kurth LLP, Houston, Texas.

EXPERTS

The financial statements as of December 31, 2007 and for the year then ended and management s assessment of the effectiveness of internal control over financial reporting (which is included in Management s Report on Internal Control over Financial Reporting) as of December 31, 2007 included in this prospectus have been so included in reliance on the report, which contains an adverse opinion on the effectiveness of internal control over financial reporting, of PricewaterhouseCoopers LLP, an independent registered public accounting firm, given on the authority of said firm as experts in auditing and accounting.

The consolidated financial statements and schedule of Petroleum Development Corporation as of December 31, 2006, and for each of the years in the two-year period ended December 31, 2006, have been included herein in reliance upon the report of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

The audit report dated May 22, 2007 covering the December 31, 2006 consolidated financial statements refers to a change in accounting for share based payments and a change in the method of quantifying errors in 2006.

INDEPENDENT PETROLEUM CONSULTANTS

Certain information with respect to the natural gas and oil reserves associated with our natural gas and oil prospects is derived from the reports of Ryder Scott Company, LP, an independent petroleum and natural gas consulting firm, and has been included in this document upon the authority of said firm as experts with respect to the matters covered by such reports and in giving such reports.

Certain information and with respect to the natural gas and oil reserves associated with our natural gas and oil prospects is derived from the reports of Wright & Company, an independent petroleum and natural gas consulting firm, and has been included in this document upon the authority of said firm as experts with respect to the matters covered by such reports and in giving such reports.

PETROLEUM DEVELOPMENT CORPORATION

Index to Consolidated Financial Statements and Financial Statement Schedule

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PETROLEUM DEVELOPMENT CORPORATION

Management s Report on Internal Control Over Financial Reporting

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

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

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

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

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

PETROLEUM DEVELOPMENT CORPORATION

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

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

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PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders

of Petroleum Development Corporation

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

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

A company s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made

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only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company s assets that could have a material effect on the financial statements.

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

/s/ PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania

March 20, 2008

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PETROLEUM DEVELOPMENT CORPORATION

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders

Petroleum Development Corporation:

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

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

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

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

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

/s/ KPMG LLP

Pittsburgh, Pennsylvania

May 22, 2007

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Balance Sheets

(in thousands, except share and per share data)

December 31,	**2007**	**2006**
Assets		
Current assets:		
Cash and cash equivalents	$ 84,751	$ 194,326
Restricted cash current	14,773	519
Accounts receivable, net	60,024	42,600
Accounts receivable affiliates	11,537	9,235
Inventories	2,248	3,345
Fair value of derivatives	4,817	15,012
Other current assets	13,643	5,977
Total current assets	191,793	271,014
Properties and equipment, net	845,864	394,217
Restricted cash long term	1,294	192,451
Goodwill		6,783
Other assets	11,528	19,822
Total Assets	$ 1,050,479	$ 884,287
Liabilities and Shareholders Equity		
Current liabilities:		
Accounts payable	$ 88,502	$ 67,675
Accounts payable affiliates	3,828	7,595
Short term debt		20,000
Production tax liability	21,330	11,497
Other accrued expenses	12,913	9,685
Deferred gain on sale of leaseholds		8,000
Federal and state income taxes payable	901	28,698
Fair value of derivatives	6,291	2,545
Advances for future drilling contracts	68,417	54,772
Funds held for distribution	39,823	31,367
Total current liabilities	242,005	241,834
Long-term debt	235,000	117,000
Deferred gain on sale of leaseholds		17,600
Other liabilities	19,968	19,400
Deferred income taxes	136,490	116,393
Asset retirement obligation	20,731	11,916
Total liabilities	654,194	524,143
Commitments and contingent liabilities		
Minority interest in consolidated limited liability company	759	
Shareholders equity:		
Common shares, par value $.01 per share; authorized 50,000,000 shares; issued 14,907,679 in 2007 and 14,834,871 in 2006	149	148
Additional paid-in capital	2,559	64

Retained earnings	393,044	360,102
Treasury shares at cost, 5,894 shares in 2007 and 4,706 in 2006	(226)	(170)
Total shareholders equity	395,526	360,144
Total Liabilities and Shareholders Equity	$ 1,050,479	$ 884,287

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Income

(in thousands, except per share data)

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

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Shareholders Equity

(in thousands, except per share data)

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

Issuance of stock awards			(603)
Amortization of stock awards			660
Reclassification of unearned compensation pursuant to the adoption of SFAS No. 123(R)		825	
Balance at end of year			(825)
Treasury stock, at cost:			
Balance at beginning of year	(170)		
Purchase of treasury shares	(646)	(66,319)	(7,879)
Retirement of treasury shares	646	66,319	7,879
Non-employee directors deferred compensation plan	(56)	(170)	
Balance at end of year	(226)	(170)	
Total shareholders equity	$ 395,526	$ 360,144	$ 188,265

See accompanying Notes to Consolidated Financial Statements.

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PETROLEUM DEVELOPMENT CORPORATION

Consolidated Statements of Cash Flows

(in thousands)

Year Ended December 31,	**2007**	**2006**	**2005**
Cash flows from operating activities:			
Net income	$ 33,209	$ 237,772	$ 41,452
Adjustments to net income to reconcile to net cash provided by operating activities:			
Deferred income taxes	12,201	86,431	3,351
Depreciation, depletion and amortization	70,844	33,735	21,116
Amortization of debt issuance costs	394		
Impairment of oil and gas properties	1,485	1,519	
Accretion of asset retirement obligation	999	515	465
Exploratory dry hole costs	1,775	1,790	11,115
Gain from sale of leaseholds	(33,291)	(328,000)	(7,669)
(Gain) loss from sale of assets	(31)	9	(207)
Expired and abandoned leases	1,786	2,169	48
Stock based compensation	2,286	1,516	660
Unrealized losses (gains) on derivative transactions	4,642	(7,620)	3,226
Excess tax benefits from stock-based compensation	(673)	(70)	
Changes in current assets and liabilities:			
(Increase) decrease in restricted cash	(14,254)	982	(836)
(Increase) in accounts receivable	(16,456)	(9,935)	(11,811)
(Increase) in accounts receivable affiliates	(2,302)	(194)	(5,319)
Decrease (increase) in inventories	1,285	1,987	(3,398)
Decrease (increase) in other current assets	4,839	(2,106)	3,482
Increase (decrease) in production tax liability	10,802	(261)	3,317
(Decrease) increase in accounts payable and accrued expenses	(10,869)	13,010	19,440
(Decrease) increase in accounts payable affiliates	(3,099)	6,116	112
Increase in advances for future drilling contracts	13,645	4,773	7,502
(Decrease) increase in federal and state income taxes payable	(27,124)	19,950	8,473
Increase (decrease) in funds held for future distribution	7,488	(575)	18,505
Other	723	3,877	(652)
Net cash provided by operating activities	60,304	67,390	112,372
Cash flows from investing activities:			
Capital expenditures	(238,988)	(146,180)	(97,390)
Acquisition of oil and gas properties, net of cash acquired	(255,661)	(18,512)	
Investment in drilling partnerships		(7,151)	(7,160)
Exploration costs		(765)	(1,918)
Decrease (increase) in restricted/designated cash	191,156	(192,416)	
Proceeds from sale of leases to partnerships	1,371	1,798	2,829
Proceeds from sale of leaseholds/assets	34,701	353,600	9,597
Net cash used in investing activities	(267,421)	(9,626)	(94,042)
Cash flows from financing activities:			
Proceeds from debt	352,000	302,000	91,000
Proceeds from short-term debt		20,000	
Payment of long-term debt	(254,000)	(209,000)	(88,000)
Payment of debt issuance costs	(1,468)	(160)	(423)
Proceeds from issuance of stock	183	31	12
Excess tax benefits from stock-based compensation	673	70	
Minority interest investment	800		
Purchase of treasury stock	(646)	(66,489)	(7,879)

Net cash provided by (used in) financing activities	97,542	46,452	(5,290)
Net (decrease) increase in cash and cash equivalents	(109,575)	104,216	13,040
Cash and cash equivalents, beginning of period	194,326	90,110	77,070
Cash and cash equivalents, end of period	$ 84,751	$ 194,326	$ 90,110

See accompanying Notes to Consolidated Financial Statements.

Supplemental Cash Flow information See Note 18.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

General

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

Principles of Consolidation

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

Cash Equivalents

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

Restricted and Designated Cash

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

Inventories

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

Derivative Financial Instruments

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

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

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

Properties and Equipment

Oil and Gas Properties.

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

Our estimates of proved reserves are based on quantities of oil and natural gas that engineering and geological analysis demonstrates, with reasonable certainty, to be recoverable from established reservoirs in the future under current operating and economic conditions. Annually, we engage independent petroleum engineers to prepare a reserve and economic evaluation of all our properties on a well-by-well basis as of December 31. Additionally, we adjust our oil and gas reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating oil and natural gas reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent our most accurate assessments possible, the subjective decisions and variances in available data for various properties increase the likelihood of significant changes in these estimates. Because estimates of reserves significantly affect our depreciation, depletion and amortization (DD&A) expense, a change in our estimated reserves could have an effect on our net income.

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

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

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

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Other Property and Equipment.

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

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

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

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

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

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

Capitalized Interest

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

Production Tax Liability

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Advances for Future Drilling Contracts

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

Income Taxes

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

Asset Retirement Obligations

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

Minority Interest in Consolidated Limited Liability Company

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

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

Retirement of Treasury Shares

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Revenue Recognition

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

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

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

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

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

The first cost-plus drilling service arrangement was entered into in late 2005 with drilling activity commencing in the first quarter of 2006. Due to the fixed-fee-percentage nature of our revenues from these services, we have determined that, in substance, we are acting as an agent, without risk of loss during the performance of the drilling activities. Accordingly, our services provided under the cost-plus drilling agreements

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

are reported on a net basis. We entered into our second and third cost-plus drilling arrangements in September 2006 and August 2007 and commenced drilling immediately.

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

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

Stock-Based Compensation

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

		Year ended December 31, 2005 *(in thousands, except per share data)*
Net income, as reported:	$	41,452
Stock-based compensation expense included in reported net income, net of tax		414
Total stock-based compensation expense determined under fair value method for all awards, net of tax		(509)
Pro forma net income	$	41,357
Earnings per share:		
Basic earnings per share, as reported and pro forma	$	2.53
Diluted earnings per share, as reported and pro forma	$	2.52

Earnings Per Share

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

Use of Estimates

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

Fair Value of Financial Instruments

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

Recent Accounting Standards

Recently Adopted Accounting Standards

In December 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), *Share-Based Payment*. In March 2005, the Securities and Exchange Commission (SEC) issued Staff Accounting

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

In May 2007, the FASB issued FASB Staff Position FIN No. 48-1, *Definition of Settlement in FASB Interpretation No. 48* (FIN No. 48-1). FIN No. 48-1 amends FIN No. 48 to provide guidance on how an entity should determine whether a tax position is effectively settled for the purpose of recognizing previously unrecognized tax benefits. The term effectively settled replaces the term ultimately settled when used to describe recognition, and the terms settlement or settled replace the terms ultimate settlement or

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ultimately settled when used to describe measurement of a tax position under FIN No. 48. FIN No. 48-1 clarifies that a tax position can be effectively settled upon the completion of an examination by a taxing authority without being legally extinguished. For tax positions considered effectively settled, an entity would recognize the full amount of tax benefit, even if the tax position is not considered more likely than not to be sustained based solely on the basis of its technical merits and the statute of limitations remains open. The adoption of FIN No. 48-1, effective January 1, 2007, did not have an incremental effect on our consolidated financial statements.

Recently Issued Accounting Standards

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

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

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

In December 2007, FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R), which replaces FASB Statement No. 141. SFAS No. 141R establishes principles and requirements for how an acquirer recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, any non-controlling interest in the acquiree and the goodwill acquired. This statement also establishes disclosure requirements which will enable users to evaluate the nature and financial effects of the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

business combination. SFAS No. 141R is effective as of the beginning of an entity s fiscal year beginning after December 15, 2008. We are evaluating the potential effect that the adoption of SFAS No. 141R will have, if any, on our consolidated financial statements when adopted in 2008.

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

NOTE 2 ACQUISITIONS

2007 Acquisitions

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

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

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

Other Acquisitions

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	(in thousands)
Current assets acquired	$ 185
Proved oil and gas properties	55,778
Unproved oil and gas properties	217
Real estate and equipment, and other assets	2,115
Non current assets	783
Asset retirement obligation	(4,043)
Other liabilities assumed	(968)
Preliminary acquisition cost	$ 54,067

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

Pro Forma Financial Information

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

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

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

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

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2006 Acquisitions

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

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

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

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

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

NOTE 3 ACCOUNTS RECEIVABLE

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

NOTE 4 PROPERTIES AND EQUIPMENT

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Suspended Well Costs

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

	2007	2006	2005
		(in thousands)	
Beginning balance at January 1	$ 765	$ 1,918	$ 4,170
Additions to capitalized exploratory well costs pending the determination of proved reserves	3,953	12,016	6,441
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(878)	(13,169)	(4,523)
Capitalized exploratory well costs charged to expense	(1,540)		(4,170)
Ending balance at December 31	$ 2,300	$ 765	$ 1,918

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

NOTE 5 LONG-TERM DEBT

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 6 INCOME TAXES

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

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

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

* included in other current assets

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

NOTE 7 ASSET RETIREMENT OBLIGATIONS

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

	2007	2006
	(in thousands)	
Balance at beginning of year	$ 11,966	$ 8,333
Obligations assumed with development activities and acquisitions	7,909	1,264
Obligations discharged with disposed properties and asset retirements	(93)	(115)
Accretion expense	999	515
Revisions to estimated cash flows		1,969
Balance at end of year	$ 20,781	$ 11,966

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

NOTE 8 COMMITMENTS AND CONTINGENCIES

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

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

NOTE 9 COMMON STOCK

Stock-Based Compensation Plans

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

As approved by the shareholders in June 2005, we also maintain a restricted stock plan for non-employee directors. A total of 40,000 new shares of common stock have been reserved for issuance under the plan. During

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2007, 2006 and 2005, 12,710, 6,551 and 6,895 common shares, respectively, were awarded in accordance with the plan. Compensation expense for each of the years ended December 31, 2007, 2006 and 2005, related to these restricted shares was $0.2 million, $0.1 million and $0.1 million, respectively. As of December 31, 2007, 13,844 common shares remain available for future awards.

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

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

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

Restricted Stock Awards

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

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

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

	Shares	Weighted Average Grant-Date Fair Value

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

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

Treasury Share Purchases

In January 2006, we announced that our Board authorized the purchase of up to 10% (1,627,500 shares) of our common stock during 2006. Stock purchases under this program were made in the open market or in private

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

transactions, at times and in amounts that we deemed appropriate. In October 2006, we completed our January 2006 program. Total shares purchased pursuant to the program were 1,627,500 common shares at a cost of $66.3 million ($40.75 average price paid per share), including 100,000 shares from one of our executive officers at a cost of $4.1 million ($40.66 price paid per share). All shares purchased in accordance with the program have subsequently been retired.

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

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

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

NOTE 10 SHAREHOLDERS RIGHTS AGREEMENT

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

NOTE 11 EMPLOYEE BENEFIT PLANS

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

NOTE 12 EARNINGS PER SHARE

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

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

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

NOTE 13 TRANSACTIONS WITH AFFILIATES

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

NOTE 14 LEASE OBLIGATIONS

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

NOTE 15 DERIVATIVE FINANCIAL INSTRUMENTS

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

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

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

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

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

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Petroleum Development Corporation

Open Derivative Positions

(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2007					
Natural Gas	Cash Settled Option Sales	14,500,000	$ 10.69	$ 155,044	$ (293)
Natural Gas	Cash Settled Option Purchases	16,360,000	5.76	94,283	3,366
Oil	Cash Settled Futures/Swaps Purchases	585,600	84.20	49,308	(5,097)
					$ (2,024)
Positions maturing in 12 months following December 31, 2007					
Natural Gas	Cash Settled Option Sales	14,500,000	$ 10.69	$ 155,044	$ (293)
Natural Gas	Cash Settled Option Purchases	16,360,000	5.76	94,283	3,366
Oil	Cash Settled Futures/Swaps Purchases	585,600	84.20	49,308	(5,097)
					$ (2,024)
The maximum term for the derivative contracts listed above is 12 months.					
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Option Sales	17,390,000	$ 5.56	$ 96,613	$ 12,597
Natural Gas	Cash Settled Option Purchases	2,155,000	10.34	22,287	(14)
Oil	Cash Settled Option Purchases	300,000	50.00	15,000	155
					$ 12,738

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Riley Natural Gas

Open Derivative Positions

(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas-MMbtu	Weighted Average Price	Total Contract Amount	Fair Value
Total Positions as of December 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	588,950	$ 7.79	$ 4,586	$ (246)
Natural Gas	Cash Settled Futures/Swaps Sales	2,085,400	8.50	17,722	1,236
Natural Gas	Cash Settled Basis Swap Purchases	397,500	0.54	214	3
Natural Gas	Physical Purchases	2,085,400	8.51	17,748	(473)
Natural Gas	Physical Sales	518,951	8.50	4,409	129
					$ 649
Positions maturing in 12 months following December 31, 2007					
Natural Gas	Cash Settled Futures/Swaps Purchases	588,950	$ 7.79	$ 4,586	$ (246)
Natural Gas	Cash Settled Futures/Swaps Sales	1,568,400	8.54	13,391	1,318
Natural Gas	Cash Settled Basis Swap Purchases	397,500	0.54	214	3
Natural Gas	Physical Purchases	1,568,400	8.32	13,044	(655)
Natural Gas	Physical Sales	518,951	8.50	4,409	129
					$ 549
The maximum term for the derivative contracts listed above is 48 months.					
Total Positions as of December 31, 2006					
Natural Gas	Cash Settled Futures/Swaps Purchases	246,900	$ 7.34	$ 1,811	$ (304)
Natural Gas	Cash Settled Futures/Swaps Sales	1,952,150	8.42	16,444	2,815
Natural Gas	Cash Settled Basis Swap Purchases	90,000	0.42	38	(12)
Natural Gas	Cash Settled Basis Swap Sales	20,000	0.50	10	4
Natural Gas	Cash Settled Option Purchases	220,000	5.50	1,210	64
Natural Gas	Cash Settled Option Sales	110,000	10.10	1,111	(39)
Natural Gas	Physical Purchases	1,964,150	8.27	16,244	(1,974)

Natural Gas	Physical Sales	114,974	9.62	1,106	310
Natural Gas	Physical Basis Purchases	20,000	0.45	9	(3)
Natural Gas	Physical Basis Sales	90,000	0.44	39	14
					$ 875

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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

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

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

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cost of gas marketing activities includes realized and unrealized gains and losses on commodity based derivatives related to the RNG gas sales and gas purchases, respectively.

NOTE 16 SALE OF OIL AND GAS PROPERTIES

Grand Valley Field Properties

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

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

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

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

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

Appalachian Basin Properties

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 17 BUSINESS SEGMENTS

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

Year Ended December 31,	**2007**	**2006** *(in thousands)*	**2005**
Revenues:			
Oil and gas sales[(1)]	$ 177,943	$ 124,336	$ 93,191
Natural gas marketing	103,624	131,326	121,114
Oil and gas well drilling operations	12,154	17,917	99,963
Well operations and pipeline income	9,342	10,704	8,760
Unallocated amounts	2,172	2,220	2,170
Total	$ 305,235	$ 286,503	$ 325,198
Segment Income Before Income Taxes:			
Oil and gas sales[(2)]	$ 42,068	$ 61,868	$ 46,095
Natural gas marketing	3,822	1,816	1,737
Oil and gas well drilling operations	9,646	5,300	11,778
Well operations and pipeline income[(3)]	3,136	2,823	3,539
Unallocated amounts[(4)(5)]	(4,482)	315,602	2,979
Total	$ 54,190	$ 387,409	$ 66,128

As of December 31,	**2007**	**2006**	**2005**
Segment Assets:			
Oil & gas sales	$ 862,237	$ 394,952	$ 251,897
Natural gas marketing	40,269	39,899	56,518
Oil and gas well drilling operations	4,959	87,746	89,030
Well operations and pipeline income	26,156	28,895	31,407
Unallocated amounts[(6)]	116,858	332,795	15,509
Total	$ 1,050,479	$ 884,287	$ 444,361

Year ended December 31,			
Expenditures for Segment Long-Lived Assets:			
Oil & gas sales	$ 226,801	$ 133,401	$ 92,907
Natural gas marketing			1
Oil and gas well drilling operations			

Well operations and pipeline income	6,715	1,419	3,949
Unallocated amounts	5,472	12,125	2,452
Total	$ 238,988	$ 146,945	$ 99,309

(1) Includes oil and gas price risk management gain (loss), net.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Includes $23.6, $8.1 and $11.1 million in exploration costs and $68.1, $31.3 and $19.3 million in DD&A expense in 2007, 2006 and 2005, respectively.

(3) Includes $1.2, $1.9 and $1.5 million in DD&A expense in 2007, 2006 and 2005, respectively.

(4) Includes interest income for PDC operations, $0.8, $0.6 and $0.3 million in interest income allocated to natural gas marketing in 2007, 2006 and 2005, respectively, in addition to partnership management fees.

(5) Includes $1.6, $0.5, and $0.3 million in DD&A expense in 2007, 2006 and 2005 respectively.

(6) The December 31, 2006, amount was expended in early 2007 in LKE transactions; the assets and liabilities of which have been included in the oil and gas sales segment.

NOTE 18 SUPPLEMENTAL CASH FLOW

	Year Ended December 31,		
	2007	**2006**	**2005**
		(in thousands)	
Cash paid for:			
Interest	$ 12,557	$ 3,011	$ 101
Income taxes	43,785	46,735	10,675
Non-cash investing activities:			
Change in deferred tax liability resulting from reallocation of acquisition purchase price	4,188		
Changes in accounts payable affiliates related to acquisition of partnerships	668		
Changes in accounts payable related to purchases of properties and equipment	32,820	1,800	
Changes related to investment in drilling partnership	18,712	(7,151)	(7,160)
Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	7,850	3,164	(3)

NOTE 19 SUBSEQUENT EVENTS

Issuance and Sale of Senior Notes

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

Registration Rights Agreement

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

Departure of Executive Officer

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 20 SUPPLEMENTAL OIL AND GAS INFORMATION UNAUDITED

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

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

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

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

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

Capitalized Oil and Gas Costs (Unaudited)

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

	December 31,	
	2007	2006
	(in thousands)	
Proved oil and gas properties	$ 953,904	$ 473,451
Unproved oil and gas properties	41,023	27,055
	994,927	500,506
Less accumulated depreciation, depletion and amortization	196,310	133,172
	$ 798,617	$ 367,334

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

Net Proved Oil and Gas Reserves (Unaudited)

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NOTE 21 QUARTERLY FINANCIAL DATA (UNAUDITED)

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

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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PETROLEUM DEVELOPMENT CORPORATION

Schedule II VALUATION AND QUALIFYING ACCOUNTS

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

(a) Deductions represent the write-off of accounts receivable deemed uncollectible.

(b) Deductions represent amortization of expired or abandoned unproved oil and gas properties.

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PETROLEUM DEVELOPMENT CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(in thousands, except share data)

	March 31, 2008	December 31, 2007*
Assets		
Current assets:		
Cash and cash equivalents	$ 26,202	$ 84,751
Accounts receivable, net	60,699	60,024
Accounts receivable affiliates	34,557	11,537
Fair value of derivatives	10,408	4,817
Other current assets	38,202	30,664
Total current assets	170,068	191,793
Properties and equipment, net	869,967	845,864
Other assets	35,432	12,822
Total assets	$ 1,075,467	$ 1,050,479
Liabilities and shareholders equity		
Current liabilities:		
Accounts payable	$ 84,924	$ 88,502
Accounts payable affiliates	4,401	3,828
Federal and state income taxes payable	996	901
Fair value of derivatives	57,518	6,291
Advances for future drilling contracts	40,911	68,417
Funds held for future distribution	57,223	39,823
Other accrued expenses	31,195	34,243
Total current liabilities	277,168	242,005
Long-term debt	203,000	235,000
Deferred income taxes	141,873	136,490
Other liabilities	73,141	40,699
Total liabilities	695,182	654,194
Commitments and contingencies		
Minority interest in consolidated limited liability company	743	759
Total shareholders equity	379,542	395,526
Total liabilities and shareholders equity	$ 1,075,467	$ 1,050,479

* Derived from audited 2007 balance sheet.

See accompanying notes to condensed consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(unaudited; in thousands except per share data)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Revenues:		
Oil and gas sales	$ 71,646	$ 34,016
Sales from natural gas marketing activities	23,325	21,987
Oil and gas well drilling operations	3,083	4,030
Well operations and pipeline income	2,352	3,298
Oil and gas price risk management loss, net	(42,310)	(5,645)
Other	3	226
Total revenues	58,099	57,912
Costs and expenses:		
Oil and gas production and well operations cost	18,132	9,035
Cost of natural gas marketing activities	22,121	21,512
Cost of oil and gas well drilling operations	78	564
Exploration expense	4,283	2,678
General and administrative expense	9,823	7,424
Depreciation, depletion and amortization	21,131	13,074
Total costs and expenses	75,568	54,287
Income (loss) from operations	(17,469)	3,625
Interest income	271	1,143
Interest expense	(4,932)	(831)
Income (loss) before income taxes	(22,130)	3,937
Provision (benefit) for income taxes	(8,202)	1,436
Net income (loss)	$ (13,928)	$ 2,501
Earnings (loss) per share		
Basic	$ (0.95)	$ 0.17
Diluted	$ (0.95)	$ 0.17
Weighted average common shares outstanding		
Basic	14,738	14,726
Diluted	14,738	14,854

See accompanying notes to condensed consolidated financial statements.

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PETROLEUM DEVELOPMENT CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited, in thousands)

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Cash flows from operating activities:		
Net income (loss)	$ (13,928)	$ 2,501
Adjustments to net income (loss) to reconcile to cash provided by (used in) operating activities:		
Deferred income taxes	(9,738)	(3,379)
Depreciation, depletion and amortization	21,131	13,074
Amortization of debt issuance costs	256	
Accretion of asset retirement obligation	304	232
Exploratory dry hole costs	1,100	194
Expired and abandoned leases	442	53
Unrealized loss on derivative transactions	39,334	6,636
Changes in assets and liabilities	8,401	(52,532)
Other	1,487	483
Net cash provided by (used in) operating activities	$ 48,789	$ (32,738)
Cash flows from investing activities:		
Capital expenditures	(64,321)	(13,378)
Acquisitions		(201,488)
Decrease in restricted cash for property acquisition		191,452
Other	204	385
Net cash used in investing activities	(64,117)	(23,029)
Cash flows from financing activities:		
Proceeds from credit facility	42,000	70,000
Repayment of credit facility	(277,000)	(147,000)
Proceeds from senior notes	200,101	
Payment of debt costs	(4,486)	
Proceeds from exercise of stock options	367	152
Excess tax benefits from stock based compensation	154	
Purchase of treasury stock	(4,357)	(135)
Net cash used in financing activities	(43,221)	(76,983)
Net decrease in cash and cash equivalents	(58,549)	(132,750)
Cash and cash equivalents, beginning of period	84,751	194,326
Cash and cash equivalents, end of period	$ 26,202	$ 61,576
Supplemental disclosure of cash flow information of cash payments for:		
Interest	$ 2,721	$ 2,205
Income taxes	2,774	24,781
Supplemental schedule of non-cash investing and financing activities:		
Change in deferred tax liability resulting from reallocation of acquisition purchase price		4,188
Changes in accounts payable related to the acquisitions of partnerships		668

Changes in accounts payable related to purchase of properties and equipment	(11,383)	17,563
Asset retirement obligation, with a corresponding increase to oil and gas properties, net of disposals	133	4,738
Changes in accounts payable related to debt costs	306	

See accompanying notes to condensed consolidated financial statements.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

March 31, 2008

(unaudited)

1. GENERAL

Petroleum Development Corporation (PDC), together with our consolidated entities (the Company), is an independent energy company engaged primarily in the exploration, development, production and marketing of oil and natural gas. Since we began oil and natural gas operations in 1969, we have grown primarily through exploration and development activities, the acquisition of producing oil and natural gas wells and the expansion of our natural gas marketing activities.

The accompanying interim condensed consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries and WWWV, LLC, an entity in which we have a controlling financial interest. All material intercompany accounts and transactions have been eliminated in consolidation. Minority interest in earnings and ownership has been recorded for the percentage of the LLC we do not own for each of the applicable periods. We account for our investment in interests in oil and natural gas limited partnerships under the proportionate consolidation method. Accordingly, our accompanying interim condensed consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the limited partnerships in which we participate. Our proportionate share of all significant transactions between us and the limited partnerships is eliminated.

The accompanying interim condensed consolidated financial statements have been prepared without audit in accordance with accounting principles generally accepted in the United States of America for interim financial information and with the instructions to Form 10-Q and Article 10 of Regulation S-X of the Securities and Exchange Commission (SEC). Accordingly, pursuant to such rules and regulations, certain notes and other financial information included in audited financial statements have been condensed or omitted. In our opinion, the accompanying interim condensed consolidated financial statements contain all adjustments (consisting of only normal recurring adjustments) necessary to present fairly our financial position, results of operations and cash flows for the periods presented. The interim results of operations for the three months ended March 31, 2008, and the interim cash flows for the same interim period, are not necessarily indicative of the results to be expected for the full year or any other future period.

The accompanying interim condensed consolidated financial statements should be read in conjunction with our audited consolidated financial statements and notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2007, as filed with the SEC on March 20, 2008 (2007 Form 10-K).

2. RECENT ACCOUNTING STANDARDS

Recently Adopted Accounting Standards

We adopted the provisions of Statement of Financial Accounting Standards (SFAS) No. 157, *Fair Value Measurements*, effective January 1, 2008. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures related to fair value measurements. SFAS No. 157 applies broadly to financial and nonfinancial assets and liabilities that are measured at fair value under other authoritative accounting pronouncements, but does not expand the application of fair value accounting to any new circumstances. In February 2008, the Financial Accounting Standards Board (FASB) issued FASB Staff Position (FSP) FAS No. 157-2, *Effective Date of FASB Statement No. 157*, which delays the effective date of SFAS No. 157 by one year (to January 1, 2009) for nonfinancial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). Nonfinancial assets and liabilities for which we have not applied the provisions of SFAS No. 157 include those initially measured at fair value, including our asset retirement obligations. As of the adoption date, we have

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

applied the provisions of SFAS No. 157 to our recurring measurements and the impact was not material to our underlying fair values and no amounts were recorded relative to the cumulative effect of a change in accounting. We are currently evaluating the potential effect that the nonfinancial assets and liabilities provisions of SFAS No. 157 will have on our financial statements when adopted in 2009. See Note 5 for further details on our fair value measurements.

In February 2007, the FASB issued SFAS No. 159, *The Fair Value Option for Financial Assets and Financial Liabilities*. SFAS No. 159 permits entities to choose to measure, at fair value, many financial instruments and certain other items that are not currently required to be measured at fair value. The objective is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. SFAS No. 159 establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. The statement will be effective as of the beginning of an entity s first fiscal year beginning after November 15, 2007. As of March 31, 2008, we had not elected, nor do we intend, to measure additional financial assets and liabilities at fair value.

In April 2007, the FASB issued FSP No. FIN 39-1, *Amendment of FASB Interpretation No. 39* (FIN 39-1), to amend certain portions of Interpretation 39. FIN 39-1 replaces the terms conditional contracts and exchange contracts in Interpretation 39 with the term derivative instruments as defined in Statement 133. FIN 39-1 also amends Interpretation 39 to allow for the offsetting of fair value amounts for the right to reclaim cash collateral or receivable, or the obligation to return cash collateral or payable, arising from the same master netting arrangement as the derivative instruments. FIN 39-1 applies to fiscal years beginning after November 15, 2007, with early adoption permitted. The January 1, 2008, adoption of FSP FIN 39-1 had no impact on our financial statements.

Recently Issued Accounting Standards

In December 2007, the FASB issued SFAS No. 141 (revised 2007), *Business Combinations* (SFAS No. 141R). SFAS No. 141R requires an acquirer to recognize the assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree at their acquisition-date fair values. SFAS No. 141R also requires disclosure of the information necessary for investors and other users to evaluate and understand the nature and financial effect of the business combination. Additionally, SFAS No. 141R requires that acquisition-related costs be expensed as incurred. The provisions of SFAS No. 141R will become effective for acquisitions completed on or after January 1, 2009; however, the income tax provisions of SFAS No. 141R will become effective as of that date for all acquisitions, regardless of the acquisition date. SFAS No. 141R amends SFAS No. 109, *Accounting for Income Taxes*, to require the acquirer to recognize changes in the amount of its deferred tax benefits recognizable due to a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141R further amends SFAS No. 109 and FIN 48, *Accounting for Uncertainty in Income Taxes*, to require, subsequent to a prescribed measurement period, changes to acquisition-date income tax uncertainties to be reported in income from continuing operations and changes to acquisition-date acquiree deferred tax benefits to be reported in income from continuing operations or directly in contributed capital, depending on the circumstances.

In December 2007, the FASB issued SFAS No. 160, *Noncontrolling Interests in Consolidated Financial Statements An Amendment of ARB No. 51*. SFAS No. 160 states that accounting and reporting for minority interests will be recharacterized as non-controlling interests and classified as a component of equity. Additionally, SFAS No. 160 establishes reporting requirements that provide sufficient disclosures which clearly

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

identify and distinguish between the interests of the parent and the interests of the non-controlling owners. SFAS No. 160 is effective as of the beginning of an entity s first fiscal year beginning after December 15, 2008. We do not expect the adoption of SFAS No. 160 to have a material effect on our financial statements and related disclosures.

In March 2008, the FASB issued SFAS No. 161, *Disclosures about Derivative Instruments and Hedging Activities An Amendment of FASB Statement No. 133*, which changes the disclosure requirements for derivative instruments and hedging activities. Enhanced disclosures are required to provide information about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations and (c) how derivative instruments and related hedged items affect an entity s financial position, financial performance and cash flows. SFAS No. 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. As SFAS No. 161 is disclosure related, we do not expect its adoption to have a material impact on our financial statements.

3. PROPERTIES AND EQUIPMENT

	March 31, 2008	December 31, 2007
	(in thousands)	
Properties and equipment, net:		
Oil and gas properties (successful efforts method of accounting)		
Proved	$ 994,206	$ 953,904
Unproved	41,938	41,023
Total oil and gas properties	1,036,144	994,927
Pipelines and related facilities	23,023	22,408
Transportation and other equipment	27,389	23,669
Land and buildings	13,898	11,303
Construction in progress(1)		2,929
	1,100,454	1,055,236
Accumulated depreciation, depletion and amortization (DD&A)	(230,487)	(209,372)
	$ 869,967	$ 845,864

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Suspended Well Costs.

The following table identifies the capitalized exploratory well costs that are pending determination of proved reserves and are included in properties and equipment in the accompanying condensed consolidated balance sheets in accordance with FSP No. 19-1, *Accounting for Suspended Well Costs*.

	Amount *(in thousands)*	Number of Wells
Beginning balance at December 31, 2007	$ 2,300	3
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,483	7
Reclassifications to wells, facilities and equipment based on the determination of proved reserves		
Capitalized exploratory well costs charged to expense	(1,100)	(1)
Ending balance at March 31, 2008	$ 5,683	9

As of March 31, 2008, none of the nine suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year.

4. DERIVATIVE FINANCIAL INSTRUMENTS

We account for derivative financial instruments in accordance with Statement of Financial Accounting Standards (SFAS) No. 133, Accounting for Derivative Instruments and Certain Hedging Activities, as amended. Our derivative instruments do not qualify for use of hedge accounting under the provisions of SFAS No. 133. Accordingly, we recognize all derivative instruments as either assets or liabilities on our accompanying condensed consolidated balance sheets at fair value. Changes in the derivatives fair values are recorded on a net basis in our accompanying condensed consolidated statements of operations in oil and gas price risk management, net, for changes in derivative instruments related to our oil and gas sales and in sales from and cost of natural gas marketing activities for changes in derivative instruments related to our natural gas marketing activities.

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

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 (i) New York Mercantile Exchange (NYMEX) -traded natural gas futures contracts and option contracts for Appalachian and Michigan production, (ii) Panhandle Eastern Pipeline (PEPL) -based contracts for Northeastern Colorado (NECO) production, (iii) Colorado Interstate Gas Index (CIG) -based contracts for other Colorado production and (iv) NYMEX-based swaps and collars for our Colorado oil production.

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

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

We purchase puts and set collars and fixed-price swaps for our own and affiliate partnerships production to protect against price declines in future periods while retaining some of the benefits of price increases.

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 virtually eliminate 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, although they are currently below market due to the continual rises in energy prices.

The following table summarizes our open derivative positions as of March 31, 2008.

Open Derivative Positions

As of March 31, 2008

(dollars in thousands, except average price data)

Commodity	Type	Quantity Gas MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Total Fair Value	Positions maturing in 12 months of March 31, 2008: Quantity Gas MMbtu Oil-Barrels	Weighted Average Price	Total Contract Amount	Fair Value Current Portion
Total positions in effect for oil and gas sales[1]									
Natural gas	Cash settled option sales	44,910,000	$ 9.06	$ 406,865	$ (15,187)	28,670,000	$ 8.71	$ 249,760	$ (9,906)
Natural gas	Cash settled option purchases	44,910,000	7.05	316,566	10,968	28,670,000	7.65	219,266	3,805
Natural gas	Cash settled futures/swaps purchases	25,970,000	7.52	195,285	(34,241)	23,900,000	7.42	177,442	(33,147)
Oil	Cash settled futures/swaps purchases	1,170,000	84.79	99,208	(14,147)	620,000	84.48	52,375	(8,766)
Oil	Cash settled option sales	730,000	102.63	74,916	(7,052)				
Oil	Cash settled option purchases	730,000	70.00	51,100	2,690				
					$ (56,969)				$ (48,014)
Total positions in effect for natural gas marketing activities[2]									
Natural gas	Cash settled futures/swaps purchases	245,030	$ 6.79	$ 1,663	$ 55	245,030	$ 6.79	$ 1,663	$ 55
Natural gas	Cash settled futures/swaps	4,551,300	8.65	39,391	(6,225)	3,160,800	8.63	27,275	(5,655)

	sales										
Natural gas	Physical purchases	4,351,300	8.93	38,856		7,429	2,960,800	8.96	26,528		6,548
Natural gas	Physical sales	35,030	9.45	331		(44)	35,030	9.45	331		(44)
					$	1,215				$	904

(1) The maximum term for the derivative positions is 35 months.
(2) The maximum term for the derivative positions is 45 months.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

In addition to including the gross assets and liabilities related to our share of oil and gas production, the above tables and our condensed consolidated balance sheets include the gross assets and liabilities related to derivative contracts we entered into on behalf of our affiliate partnerships as the managing general partner. Our condensed consolidated balance sheets include the fair value of derivatives and a corresponding net receivable from the partnerships of $16.5 million at March 31, 2008, and a corresponding net receivable from the partnerships of $1.5 million at December 31, 2007.

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

	March 31, 2008	December 31, 2007
	(in thousands)	
Classification in the Condensed Consolidated Balance Sheets:		
Fair value of derivatives current asset	$ 10,408	$ 4,817
Other assets long-term asset	10,734	193
	21,142	5,010
Fair value of derivatives current liability	57,518	6,291
Other liabilities long-term liability	19,378	93
	76,896	6,384
Net fair value of commodity based derivatives	$ (55,754)	$ (1,374)

The following changes in the fair value of commodity based derivatives are reflected in the condensed consolidated statements of income:

	Three Months Ended March 31,			
	2008		2007	
Statement of income line item	**Realized**	**Unrealized**	**Realized**	**Unrealized**
	(in thousands, gains/(losses))			
Oil and gas price risk management gain (loss), net[(1)]	$ (2,411)	$ (39,899)	$ 580	$ (6,225)
Sales from natural gas marketing activities	486	(7,638)	1,097	(3,298)
Cost of natural gas marketing activities	66	8,203	(174)	2,887

(1) Represents net realized and unrealized gains and losses on commodity based derivative instruments related to oil and gas sales.

5. FAIR VALUE MEASUREMENTS

As described above in Note 2, in September 2006, the FASB issued SFAS No. 157, *Fair Value Measurements*. We adopted the provisions of SFAS No. 157 effective January 1, 2008.

Valuation hierarchy. SFAS No. 157 establishes a fair value hierarchy that requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date, giving the highest priority to quoted prices in active markets (Level 1) and the lowest priority to unobservable data (Level 3). In some cases, the inputs used to measure fair value might fall in different levels of the fair value hierarchy. The lowest level input that is significant to a fair value measurement in its entirety

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

determines the applicable level in the fair value hierarchy. Assessing the significance of a particular input to the fair value measurement in its entirety requires judgment, considering factors specific to the asset or liability. The three levels of inputs that may be used to measure fair value are defined as:

Level 1 Quoted prices (unadjusted) in active markets for identical assets or liabilities. Instruments included in Level 1 consist of our commodity derivatives for NYMEX-based natural gas swaps.

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

Level 3 Unobservable inputs for the asset or liability, including situations where there is little, if any, market activity for the asset or liability. Instruments included in Level 3 consist of our commodity derivatives for CIG and PEPL based natural gas swaps, oil swaps, oil and natural gas options, and physical sales and purchases.

Determination of fair value. We measure fair value based upon quoted market prices, where available. Our valuation determination includes: (1) identification of the inputs to the fair value methodology through the review of counterparty statements and other supporting documentation, (2) determination of the validity of the source of the inputs, (3) corroboration of the original source of inputs through access to multiple quotes, if available, or other information and (4) monitoring changes in valuation methods and assumptions. The methods described above may produce a fair value calculation that may not be indicative of future fair values. Our valuation determination also gives consideration to our nonperformance risk on our own liabilities as well as the credit standing of our counterparties. Furthermore, while we believe these valuation methods are appropriate and consistent with that used by other market participants, the use of different methodologies, or assumptions, to determine the fair value of certain financial instruments could result in a different estimate of fair value.

SFAS No. 157 requires fair value measurements to be separately disclosed by level within the fair value hierarchy and requires a separate reconciliation of fair value measurements categorized as Level 3. The following table presents, for each hierarchy level, our assets and liabilities, including both current and non-current portions, measured at fair value on a recurring basis as of March 31, 2008:

	Level 1	Level 2	Level 3	Total
Assets:				
Commodity based derivatives	$ 55	$	$ 21,087	$ 21,142
Liabilities				
Commodity based derivatives	(14,011)	$	(62,885)	$ (76,896)
Net fair value of commodity based derivatives	$ (13,956)	$	$ (41,798)	$ (55,754)

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table sets forth a reconciliation of our Level 3 fair value measurements:

	Derivatives(1) (in thousands)
Balance at January 1, 2008	$ (2,368)
Total realized and unrealized gains or (losses), net:	
Included in oil and gas price risk management, net	(982)
Included in sales from natural gas marketing activities	(22)
Included in cost of natural gas marketing activities	(5)
Purchases, sales, issuances and settlements, net	(38,421)
Balance at March 31, 2008	$ (41,798)
Total gains (losses) attributable to the change in unrealized gain (loss), net relating to assets still held as of March 31, 2008:	
Included in oil and gas price risk management, net	$ (1,009)
Included in sales from natural gas marketing activities	
Included in cost of natural gas marketing activities	
Total	$ (1,009)

(1) Derivative assets and liabilities are presented on a net basis.

6. LONG-TERM DEBT

Long-term debt consists of the following:

	March 31, 2008	December 31, 2007
	(in thousands)	
Credit facility	$	$ 235,000
12% Senior notes due 2018	203,000	
Total long-term debt	$ 203,000	$ 235,000

Credit facility

We have a credit facility with JPMorgan Chase Bank, N.A. (JPMorgan) and BNP Paribas, as amended, dated as of November 4, 2005, with an activated commitment of $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, FSB; Royal Bank of Canada; and The Royal Bank of Scotland, plc. The maximum allowable commitment under the current credit facility is $400 million. The credit facility is subject to and secured by required levels of oil and natural gas reserves. The credit facility requires an aggregated security of a value no less than 80% of the value of the direct interests included in the borrowing base properties. We are required to pay a commitment fee of .25% to .375% per annum on the unused portion of the activated credit facility. Interest accrues at an alternative base rate (ABR) or adjusted LIBOR at our discretion. The ABR is the greater of JPMorgan s prime rate, an adjusted secondary market rate for a three-month certificate of deposit plus 1% or the federal funds effective rate plus .5%. ABR borrowings are assessed an additional margin spread up to .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.

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

As of March 31, 2008, our credit facility was undrawn compared to $235 million as of December 31, 2007. The borrowing rate on the outstanding balance was 7.07% as of December 31, 2007. Future amounts outstanding under the credit facility will be secured by substantially all of our properties. We were in compliance with all covenants at March 31, 2008, and expect to remain in compliance throughout 2008.

12% Senior Notes Due 2018

Our outstanding 12% senior notes were issued on February 8, 2008. The principal amount of the senior notes is $203 million, which is payable at maturity on February 15, 2018. Interest is payable in cash semi-annually in arrears on each February 15 and August 15, commencing on August 15, 2008. The senior notes were issued at a price of 98.572% of the principal amount. In addition, we capitalized $5.4 million in costs associated with the issuance of the debt which has been capitalized as a deferred loan cost. The original discount and the deferred loan costs are being amortized to interest expense over the term of the debt using the effective interest method.

The indenture governing the notes contains customary representations and warranties as well as typical restrictive covenants that, among other things, limit our ability and the ability of our restricted subsidiaries to incur additional debt; make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock; sell assets, including capital stock of our restricted subsidiaries; restrict dividends or other payments by restricted subsidiaries; create liens that secure debt; enter into transactions with affiliates; and merge or consolidate with another company. We were in compliance with all covenants as of March 31, 2008, and expect to remain in compliance throughout 2008.

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

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

- a subsidiary is a guarantor under our senior credit facility; and

- the subsidiary has consolidated tangible assets that constitute 10% or more of our consolidated tangible assets.

Subject to specified exceptions, any subsidiary guarantor will be restricted from entering into certain transactions including the disposition of all or substantially all of its assets or merging with or into another entity. Subsidiary guarantors may be released from a guarantee under circumstances specified in the indenture.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

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

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

In connection with the issuance of the notes, we entered into a registration rights agreement with the initial purchasers in which we agreed to file a registration statement with the SEC related to an offer to exchange the notes for other freely tradable notes and to use commercially reasonable efforts to cause the registration statement to become effective on or prior to February 7, 2009. If we fail to comply with certain obligations under the registration rights agreement, a situation that is not expected to occur, we will be required to pay liquidated damages to the holders of the notes in an amount equal to $.05 per week per $1,000 principal amount held by the holder for the first 90-day period immediately following the default. The amount of the liquidated damages increases by an additional $.05 per week per $1,000 principal amount held by the holder with respect to each subsequent 90-day period until the default has been cured, up to a maximum amount of liquidated damages of $.20 per week per $1,000 principal amount held by the holder. On April 24, 2008, we filed the related registration statement on Form S-4. As of the date of this filing, the registration statement has not yet been declared effective.

7. COMMITMENTS AND CONTINGENCIES

Drilling and Development Agreements. We are a party to a pipeline expansion agreement with an unrelated third party, which is also currently the purchaser of the majority of our Wattenberg Field natural gas production. Pursuant to the agreement, we have agreed to invest a minimum of $65 million to develop specified acreage in the Wattenberg Field, during a three-year period ending December 31, 2009. Such capital spending will include costs to drill new wells and the cost to recomplete existing wells in this area. Should we not meet the minimum commitment by December 31, 2009, we will be required to pay liquidated damages of $2 million, prorated based on our actual capital investment made to date. As of March 31, 2008, our total capital expenditures pursuant to the agreement were $41.7 million, resulting in a maximum potential obligation for liquidating damages of $0.7 million.

In connection with the acquisition of oil and gas properties in October 2007 from an unaffiliated party, we are obligated to drill 100 wells in the Appalachian Basin by January 2016. We will retain a majority interest in each well drilled. For each well we fail to drill, we are obligated to pay to the seller liquidated damages of $25,000 per undrilled well for a total contingent obligation of $2.5 million or reassign to the seller the interest acquired in the number of undrilled well locations. As of March 31, 2008, no wells had been drilled pursuant to this agreement.

Partnership Repurchase Provision. Substantially all of our drilling programs contain a repurchase provision where investing partners may request that we purchase their partnership units at any time beginning with the third anniversary of the first cash distribution. The provision provides that we are obligated to purchase an

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

aggregate of 10% of the initial subscriptions per calendar year (at a minimum price of four times the most recent 12 months cash distributions), if repurchase is requested by investors, and subject to our financial ability to do so. The maximum annual repurchase obligation as of March 31, 2008, was approximately $7 million. We have adequate liquidity to meet this obligation. During the first three months of 2008 and 2007, we paid $0.8 million and $1.6 million, respectively, under this provision for the repurchase of partnership units.

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

Drilling Rig Contracts. In order to secure the services for drilling rigs, we made commitments to the drilling contractors, which call for a minimum commitment of $12,500 daily for a specified amount of time if we cease to use the drilling rigs, an event that is not anticipated to occur, and a maximum commitment of $40,680 daily for a specified amount of time for daily use of the drilling rigs. As of March 31, 2008, commitments for these two separate contracts expire in August 2009 and July 2010. As of March 31, 2008, we have an outstanding minimum commitment for $6 million and an outstanding maximum commitment for $22.9 million.

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

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

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

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

In the event of termination without cause or if an executive officer terminates employment for good reason, the executive officer is entitled to receive a payment in the amount of three times the sum of his highest base

PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

salary during the previous two years of employment immediately preceding the termination date and his highest bonus received during the same two year period. The executive officer is also entitled to (i) vesting of any unvested equity compensation, (ii) reimbursement for any unpaid expenses, (iii) retirement benefits earned under the current and/or previous agreements, (iv) continued coverage under our medical plan for up to 18 months, and (v) payment of a pro rata bonus amount. In addition, the executive officer is entitled to receive any benefits that he would have otherwise been entitled to receive under our 401(k) and profit sharing plan, although those benefits are not increased or accelerated.

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

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

8. STOCK-BASED COMPENSATION

We maintain equity compensation plans for officers, certain key employees and non-employee directors. In accordance with the plans, awards may be issued in the form of stock options, stock appreciation rights and restricted stock. Through the date of this report, we have not issued any stock appreciation rights.

The following table provides a summary of the impact of our stock based compensation plans on the results of operations for the periods presented.

	Three Months Ended March 31,	
	2008	**2007**
	(in thousands)	
Total stock-based compensation expense	$ 1,792(1)	$ 483
Income tax benefit	(691)	(186)
Net income impact	$ 1,101	$ 297

(1) Includes $1.1 million related to the separation agreement with our former president.

Stock Option Awards. We granted stock options in previous years under several stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. There were no stock option awards for the three months ended March 31, 2008 and 2007.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table provides a summary of our stock option award activity for the three months ended March 31, 2008:

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding at December 31, 2007	51,567	$ 33.55	6.4	$ 1.3
Exercised	(8,829)	41.51		0.2
Outstanding at March 31, 2008	42,738	31.90	5.9	1.6
Vested and expected to vest at March 31, 2008	37,512	30.39	5.6	1.5
Exercisable at March 31, 2008	29,283	26.89	5.0	1.2

Total unrecognized stock-based compensation cost related to stock options expected to vest was $0.1 million as of March 31, 2008. This cost is expected to be recognized over a weighted average period of 1.5 years. As of March 31, 2008, stock-based compensation related to stock options not expected to vest and unamortized was $0.1 million.

Restricted Stock Awards

We began issuing shares of restricted common stock to employees in 2004 and to non-employee directors in 2005. Vesting conditions for our restricted stock awards are either time-based or market-based.

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

The following table sets forth the changes in non-vested time-based awards for the three months ended March 31, 2008:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2007	171,845	$ 44.38
Granted	56,497	67.51
Vested	(26,507)	50.36
Forfeited	(2,891)	41.81
Non-vested at March 31, 2008	198,944	$ 51.04

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized as of March 31, 2008, is $8.1 million. This cost is expected to be recognized over a weighted-average period of 2.8 years. As of March 31, 2008, stock-based compensation related to time-based awards not expected to vest and unamortized was $0.6 million.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily over three years for market-based awards. The market-based shares vest only upon the

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

achievement of certain per share price thresholds and continuous employment during the vesting period. All compensation cost related to the market based-awards will be recognized if the requisite service period is fulfilled, even if the market condition is not achieved.

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

	Three Months Ended March 31, 2008	Three Months Ended March 31, 2007
Expected term of award	3 years	3 years
Risk-free interest rate	2.4%	4.7%
Volatility	47.0%	44.0%

The following table sets forth the changes in non-vested marked-based awards for the three months ended March 31, 2008:

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2007	31,972	$ 36.07
Granted	48,405	45.15
Vested	(3,078)	52.00
Forfeited	(4,616)	36.07
Non-vested at March 31, 2008	72,683	$ 43.64

The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized as of March 31, 2008, is $1.3 million. This cost is expected to be recognized over a weighted-average period of 2.8 years. As of March 31, 2008, stock-based compensation related to market-based awards not expected to vest and unamortized was $1.6 million.

9. INCOME TAXES

We evaluate the estimated annual effective income tax rate on a quarterly basis based on current and forecasted business results and enacted tax laws. This estimated annual effective tax rate is updated quarterly based upon actual results and updated operating forecasts. Tax expenses or tax benefits unrelated to current year ordinary income or loss are recognized entirely in the period identified as discrete items of tax. The quarterly income tax provision is comprised of tax on ordinary income or tax benefit on ordinary loss at the most recent estimated annual effective tax rate, adjusted for the effect of discrete items.

Our effective tax rate, inclusive of discrete items, was 37.1% for the first quarter of 2008, relatively unchanged from 36.5% for the first quarter of 2007. Our rate differs from the combined federal and state statutory rates (net of the federal benefit), primarily due to certain business incentives such as percentage depletion and the domestic production deduction. Discrete items were not significant.

As of March 31, 2008, we had a gross liability for uncertain tax benefits of $0.9 million, of which $0.4 million, if recognized, would affect our effective tax rate. There were no significant changes to the calculation since year end 2007.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Internal Revenue Service (IRS) has begun its examination of our 2005 and 2006 tax years, and we currently expect this examination to be completed within one year. Therefore, we expect the amount noted above, that is accrued for uncertain tax benefits in our current tax liability on our balance sheet, to be reduced during the next year.

Our Michigan Single Business Tax returns for the tax years 2002 through 2006 are currently under examination by the Michigan Department of Treasury. No significant tax adjustments have been proposed and none are currently expected. We are current with our income tax filings in other state jurisdictions and currently have no other state income tax returns in the process of examination or administrative appeal.

10. EARNINGS PER SHARE

A reconciliation of basic and diluted earnings per common share is as follows:

	Three Months Ended March 31,	
	2008	**2007**
	(in thousands, except per share data)	
Weighted average common shares outstanding	14,738	14,726
Dilutive effect of share-based compensation:[1]		
Unamortized portion of restricted stock		63
Stock options		60
Non employee director deferred compensation		5
Weighted average common and common equivalent shares outstanding	14,738	14,854
Net income (loss)	$ (13,928)	$ 2,501
Basic earnings (loss) per common share	$ (0.95)	$ 0.17
Diluted earnings (loss) per common share	$ (0.95)	$ 0.17

(1) For the three months ended March 31, 2008, 70, 38 and 6 average common share equivalents related to unvested restricted stock, stock options and shares related to non employee director deferred compensation, respectively, were excluded from the computation of diluted net loss per share as their effect was anti-dilutive. For the three months ended March 31, 2007, there were no common share equivalents excluded from the computation of diluted net income per share.

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PETROLEUM DEVELOPMENT CORPORATION

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. BUSINESS SEGMENTS

Our operating activities can be divided into four major segments: oil and gas sales, natural gas marketing, oil and gas well drilling operations, and well operations and pipeline income. We drill natural gas wells for Company-sponsored drilling partnerships and retain an interest in each well. A wholly-owned subsidiary, Riley Natural Gas, engages in the marketing of natural gas to commercial and industrial end-users. We own an interest in approximately 4,400 wells from which we sell our oil and gas production from our working interests in the wells. We charge Company-sponsored partnerships and other third parties competitive industry rates for well operations and gas gathering. All material inter-company accounts and transactions between segments have been eliminated. Segment information for the three months ended March 31, 2008 and 2007 is presented below.

	Three Months Ended March 31,	
	2008	2007
	(in thousands)	
Revenues:		
Oil and gas sales[1]	$ 29,336	$ 28,371
Natural gas marketing	23,325	21,987
Oil and gas well drilling operations	3,083	4,030
Well operations and pipeline income	2,352	3,298
Unallocated amounts	3	226
Total	$ 58,099	$ 57,912
Segment income (loss) before income taxes:		
Oil and gas sales[1][2]	$ (11,994)	$ 5,839
Natural gas marketing	1,332	679
Oil and gas well drilling operations	3,005	3,467
Well operations and pipeline income[3]	592	1,234
Unallocated amounts[4]	(15,065)	(7,282)
Total	$ (22,130)	$ 3,937

(1) Includes oil and gas price risk management loss, net of $42.3 million and $5.6 million for the three months ended March 31, 2008 and 2007, respectively.
(2) Includes $4.3 million and $2.7 million in exploration costs and $20.3 million and $12.4 million of DD&A expense for the three months ended March 31, 2008 and 2007, respectively.
(3) Includes $0.4 million and $0.5 million of DD&A expense for the three months ended March 31, 2008 and 2007, respectively.
(4) Includes general and administrative expense, interest income, interest expense, and DD&A expense of $0.5 million and $0.2 million for the three months ended March 31, 2008 and 2007, respectively.

	March 31, 2008	December 31, 2007
	(in thousands)	
Segment assets:		
Oil & gas sales	$ 882,469	$ 862,237

Natural gas marketing	39,543	40,269
Oil and gas well drilling operations	8,233	4,959
Well operations and pipeline income	54,814	26,156
Unallocated amounts	90,408	116,858
Total	$ 1,075,467	$ 1,050,479

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UNTIL AUGUST 21, 2008, ALL DEALERS THAT EFFECT TRANSACTIONS IN THESE SECURITIES, WHETHER OR NOT PARTICIPATING IN THIS OFFERING, MAY BE REQUIRED TO DELIVER A PROSPECTUS. THIS IS IN ADDITION TO THE DEALERS OBLIGATION TO DELIVER A PROSPECTUS WHEN ACTING AS UNDERWRITERS AND WITH RESPECT TO THEIR UNUSED ALLOTMENTS OR SUBSCRIPTIONS.

MAY 23, 2008