PETROLEUM DEVELOPMENT CORP
Form 10-K
February 24, 2011

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

FORM 10-K

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

For the fiscal year ended December 31, 2010

or

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

For the transition period from __________ to _________

Commission File Number 000-07246
PETROLEUM DEVELOPMENT CORPORATION
(Exact name of registrant as specified in its charter)
(Doing Business as PDC Energy)

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

1775 Sherman Street, Suite 3000
Denver, Colorado 80203
(Address of principal executive offices) (Zip Code)

Registrant's telephone number, including area code: (303) 860-5800

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	NASDAQ Global Select Market

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes £ No £

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

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

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

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

The aggregate market value of our common stock held by non-affiliates on June 30, 2010, was $489,660,892 (based on the then closing price of $25.62).

As of February 11, 2011, there were 23,463,272 shares of our common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Form is incorporated by reference to our definitive proxy statement to be filed pursuant to Regulation 14A for our 2011 Annual Meeting of Shareholders.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
2010 ANNUAL REPORT ON FORM 10-K
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PART I

REFERENCES TO THE REGISTRANT

Unless the context otherwise requires, references to "PDC," "PDC Energy," "the Company," "we," "us," "our," "ours" or "ourselves" in this report refer to the registrant, Petroleum Development Corporation and its consolidated entities. See Note 1, Nature of Operations and Basis of Presentation, to our consolidated financial statements included in this report for a description of our consolidated entities.

WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the United States ("U.S.") Securities and Exchange Commission ("SEC"). Our SEC filings are available free of charge from the SEC's website at www.sec.gov or from our website at www.petd.com. You may also read or copy any document we file at the SEC's public reference room in Washington, D.C., located at 100 F Street, N.E., Room 1580, Washington, D.C. 20549. Please call the SEC at (800) SEC-0330 for further information on the public reference room. We also make available free of charge any of our SEC filings by mail. For a mailed copy of a report, please contact Petroleum Development Corporation, Investor Relations, 1775 Sherman Street, Suite 3000, Denver, CO 80203, or call toll free (800) 624-3821.

We recommend that you view our web site for additional information, as we routinely post information that we believe is important for investors. Our web site can be used to access such information as our recent news releases, bylaws, committee charters, code of business conduct and ethics, shareholder communication policy, director nomination procedures and our whistle-blower hotline. While we recommend that you view our web site, the information available on our web site is not part of this report and is not hereby incorporated by reference.

UNITS OF MEASUREMENT

The following presents a list of units of measurement used throughout the document.

Bbl – One barrel of crude oil or NGL or 42 gallons of liquid volume.
Bcf – One billion cubic feet of natural gas volume.
Bcfe – One billion cubic feet of natural gas equivalent.
Btu – British thermal unit.
BBtu - One billion British thermal units.
MBbls – One thousand barrels of crude oil.
Mcf – One thousand cubic feet of natural gas volume.
Mcfe – One thousand cubic feet of natural gas equivalent (six Mcf of natural gas equals one Bbl of crude oil or NGL).
MMBtu – One million British thermal units.
MMcf – One million cubic feet of natural gas volume.
MMcfe – One million cubic feet of natural gas equivalent.

GLOSSARY OF INDUSTRY TERMS

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

Behind-pipe reserves - Natural gas and crude oil reserves, proved or unproved, that cannot be produced until future perforation of casing at the depth of that reservoir. Generally, these are reserves in reservoirs above currently producing zones.

CIG - Colorado Interstate Gas.

Completion - The installation of permanent equipment for the production of natural gas and crude oil.

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

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

Exit rate - Natural gas equivalent produced as of the date specified.

Exploratory well - A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir.

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

Farm-out - Transfer of all or part of the operating rights from a working interest owner to an assignee, who assumes all or some of the burden of development in return for an interest in the property. The assignor usually retains an overriding royalty interest but may retain any type of interest.

Fracturing - Procedure to stimulate production by forcing a mixture of fluid (usually water) and proppant (usually sand) into the formation under high pressure. Fracing creates artificial fractures in the reservoir rock to increase permeability and porosity.

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

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

Joint interest billing or JIB - Process of distributing the costs related to well completions and operations among working interest partners.

Natural gas liquid(s) or NGL(s) - Hydrocarbons which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature. NGLs consist primarily of ethane, propane, butane, and natural gasolines.

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

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

NYMEX - New York Mercantile Exchange.

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

PEPL - Panhandle Eastern Pipeline.

Proved developed non-producing reserves or PDNPs - 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/or (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 or PDPs - 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 - Those quantities of natural gas, NGL, crude oil and condensate, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible - from a given date forward, from known reservoirs, and under existing conditions, operating methods, and government regulations – prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

Proved undeveloped reserves or PUDs - 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 - The modification of an existing well for the purpose of producing natural gas and crude oil from a different producing formation.

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

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

Reserves - Estimated remaining quantities of natural gas and crude oil and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering natural gas and crude oil or related substances to market, and all permits and financing required to implement the project.

Royalty - An interest in a natural gas and crude 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.

Standardized measure of discounted future net cash flows - Future net cash flows discounted at a rate of 10%. Future net cash flows represent the estimated future revenues to be generated from the production of proved reserves determined in accordance with Securities and Exchange Commission guidelines, net of estimated production and future development costs, using prices and costs as of the date of estimation without future escalation, giving effect to (i) estimated future abandonment costs, net of the estimated salvage value of related equipment and (ii) future income tax expense.

Trunk line - A pipeline for the transportation of natural gas or crude oil from producing areas to refineries or terminals.

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 crude oil, regardless of whether such acreage contains proved reserves.

Wellbore - A physical hole that makes up the well, and can be cased, open or a combination of both.

Working interest - An interest in a natural gas and crude oil lease that gives the owner of the interest the right to drill and produce natural gas and crude oil on the leased acreage. It requires the owner to pay all of their share of the costs of drilling and production operations.

Workover - Major remedial operations on a producing well to restore, maintain or improve the well's production.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are forward-looking statements. 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 natural gas, NGL and crude oil production and reserves, drilling plans, future cash flows, anticipated liquidity, anticipated capital expenditures and our management's strategies, plans and objectives. However, these are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this report reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. Consequently, forward-looking statements are inherently subject to risks and uncertainties, including risks and uncertainties incidental to the exploration for, and the acquisition, development, production and marketing of natural gas and crude 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 natural gas and crude oil;
- changes in estimates of proved reserves;

- declines in the values of our natural gas and crude oil properties resulting in impairments;
- the timing and extent of our success in discovering, acquiring, developing and producing reserves;
- our ability to acquire leases, drilling rigs, supplies and services at reasonable prices;
- reductions in the borrowing base under our credit facility;
- risks incident to the drilling and operation of natural gas and crude oil wells;
- future production and development costs;
- the availability of sufficient pipeline and other transportation facilities to carry our production and the impact of these facilities on price;
- the effect of existing and future laws, governmental regulations and the political and economic climate of the U.S.;
- changes in environmental laws and the regulation and enforcement related to those laws;
- the identification of and severity of environmental events and governmental responses to the events;
- our ability to insure adequately against operational mishaps and environment events;
- the effect of natural gas and crude oil derivatives activities;
- the availability and cost of capital to us;
- our ability to consummate the prospective mergers of the 2005 partnerships and the timing of consummating these mergers, if at all;
- conditions in the capital markets; and
- losses possible from pending or future litigation.

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

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

The Company

Established in 1969, we are an independent natural gas and crude oil company that explores for and acquires, develops, produces and markets natural gas and crude oil resources. Effective July 15, 2010, we began conducting business as PDC Energy. A new logo and corporate identity accompanied this change. Our common stock continues to trade on the NASDAQ Global Select Market under the ticker symbol PETD. Our web site, www.petd.com, reflects the new PDC Energy name and brand identity. We believe that the name PDC Energy more fully portrays the range of business activities in which we engage. At our annual shareholder meeting to be held in June 2011, we plan to request our shareholders to approve and amend our articles of incorporation to formally change our corporate name to PDC Energy.

2010 Overview

The year 2009 serves to remind us just how uncertain the commodity and financial markets can be and that our response to such uncertainty is crucial to our ability to achieve growth. We spent much of our efforts in 2009 ensuring that we had sufficient liquidity to weather the uncertain economic environment by maintaining a disciplined capital expenditure program. In 2010, as the economic environment began a slow but steady recovery, we increased our capital budget and were in an opportunistic position to be able to participate in certain growth opportunities presented. With capital markets showing renewed strength and confidence late in 2010, we took the opportunity to access the markets in November 2010 and successfully completed a $132.5 million sale of equity and a $115 million issuance of 3.25% convertible senior notes. Further in November 2010, we amended our bank credit facility, increasing our maximum facility amount and extending the maturity date to November 2015.

Our 2010 capital expenditures, exclusive of acquisitions, increased 13.8% over those in 2009. Because growth in production generally lags behind the investment, as evidenced by our decrease in production in 2010 as a result of our controlled investment in 2009, we believe that the consecutive increases in quarterly production experienced during the second half of 2010 signify our return to production growth.

In addition to our focus on organic growth, our business development group was actively pursuing available opportunities. In July, we successfully completed our first acquisition in the liquid producing province of the Permian Basin in West Texas. This acquisition was strategically important for two reasons: (1) it brought us closer to achieving our natural gas/crude oil production mix goal of 65/35 and (2) it allowed us to monetize our Michigan asset group while benefiting from Internal Revenue Code Section 1031, Like Kind Exchange, with the deferral of a $6.5 million tax liability. In November 2010, we completed our second acquisition in the Permian Basin, adding to our acreage holdings an additional 5,760 contiguous net undeveloped acres. Finally, in December 2010, we completed the acquisition of four affiliated partnerships. We believe that these partnership acquisitions will allow us the opportunity to grow through an accelerated refracturing program in our liquids-rich Wattenberg Field.

Business Strategy

Our primary objectives are to increase shareholder value through the growth of our reserves and production, while operating our properties in an efficient manner to maximize the cash flow and earnings potential of our assets. To achieve meaningful increases in these key areas, we maintain an active drilling and acquisition program that focuses on low risk development of our natural gas and crude oil reserves, targets emerging plays and enables us to acquire producing and undeveloped properties with what we believe to be significant development potential. In addition, we believe we maintain a conservative and disciplined financial strategy focused on providing sufficient liquidity and balance sheet strength to execute our business strategy. Our exploration program seeks to explore in areas where we believe we have a competitive advantage through operational expertise and a low cost of entry.

Drill and Develop

Our acreage holdings consist primarily of interests in developed and undeveloped natural gas and crude oil leases with positions primarily in the Rocky Mountain Region, the Permian Basin in West Texas and, through our joint venture, PDC Mountaineer, LLC ("PDCM"), the Appalachian Basin. We seek to maximize the value of our existing wells through a program of well recompletions, refractures and workovers and believe that our holdings of undeveloped properties provide us with a number of substantial new drilling projects. For 2011, we have planned approximately 124 new gross developmental drilling projects in the Rocky Mountain Region, including 14 horizontal projects targeting the Horizontal Niobrara formation and 90 vertical projects targeting the Codell and Niobrara formations, 25 projects in the Permian Basin and 9 horizontal Marcellus projects in the Appalachian Basin. Further, we have planned approximately 140 recompletion and refracture opportunities in our Wattenberg Field.

Drilling Activities. Our primary focus in the Rocky Mountain Region is on developmental drilling in the Wattenberg Field, where we primarily produce from the Codell and Niobrara formations. In October 2010, we launched a horizontal drilling program in our Wattenberg Field targeting the liquid rich play of the Niobrara shale. We currently have two drilling rigs operating in the Wattenberg Field and one rig in the Piceance Basin, executing a natural gas project with a strong focus on cost control and reserve optimization. In the Permian Basin, we currently are focusing on developmental drilling and plan to keep at least one drilling rig operating on such projects. During 2010, in the Appalachian Basin, PDCM drilled five horizontal Marcellus shale wells to total depth, with three of them currently producing to pipeline, and began drilling a sixth well.

The following table presents the wells drilled, by operating area, during the last three years, as well as our planned 2011 drilling activity.

	Planned	Year Ended December 31,					
	2011	2010		2009		2008	
	Gross	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region							
Wattenberg Field	104	171	134.4	82	65.2	149	122.7
Grand Valley Field	12	25	25.0	1	1.0	62	54.4
Other	12	2	0.5	9	5.0	100	88.7
Total Rocky Mountain Region	128	198	159.9	92	71.2	311	265.8
Permian Basin	25	6	5.0	—	—	—	—
Appalachian Basin	9	8	4.5	8	8.0	62	62.0
Other	6	1	0.7	—	—	6	5.6
Total wells planned/drilled	168	213	170.1	100	79.2	379	333.4

The following table presents our developmental and exploratory drilling activity for the last three years. There is no correlation between the number of productive wells completed during any period and the aggregate reserves attributable to those wells. Productive wells consist of wells spudded, turned in line and producing during the period. In-process wells represent wells that have been spudded, drilled and waiting to be fractured and/or for gas pipeline connection during the period.

	Gross Drilling Activity Year Ended December 31,								
	2010			2009			2008		
	Productive	In-Process (1)	Dry	Productive	In-Process (2)	Dry	Productive	In-Process (3)	Dry
Development Wells									
Rocky Mountain Region	150	47	—	70	17	2	216	73	8
Permian Basin	—	6	—	—	—	—	—	—	—
Appalachian Basin	1	2	—	2	—	—	44	16	—
Total development wells	151	55	—	72	17	2	260	89	8
Exploratory Wells									
Rocky Mountain Region	—	1	—	2	1	—	4	3	7
Appalachian Basin	5	—	—	5	1	—	—	2	—
Other	—	1	—	—	—	—	3	—	3
Total exploratory wells	5	2	—	7	2	—	7	5	10
Total drilling activity	156	57	—	79	19	2	267	94	18

Recompletions/refractures	40	32	125

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(1) Of the 57 wells in process as of December 31, 2010, 20 were connected and turned in line by February 11, 2011.
(2) Of the 19 wells in process as of December 31, 2009, all were connected and turned in line in 2010.
(3) Of the 94 wells in process as of December 31, 2008, 81 were connected and turned in line in 2009 and 13 were shut-in and are awaiting completion of a pipeline.

	Net Drilling Activity								
	Year Ended December 31,								
	2010			2009			2008		
	Productive	In-Process	Dry	Productive	In-Process	Dry	Productive	In-Process	Dry
Development Wells									
Rocky Mountain Region	125.4	33.5	—	61.3	6.9	1.0	174.0	69.8	8.0
Permian Basin	—	5.0	—	—	—	—	—	—	—
Appalachian Basin	0.6	1.1	—	2.0	—	—	44.0	16.0	—
Total development wells	126.0	39.6	—	63.3	6.9	1.0	218.0	85.8	8.0
Exploratory Wells									
Rocky Mountain Region	—	1.0	—	1.0	1.0	—	4.0	3.0	7.0
Appalachian Basin	2.8	—	—	5.0	1.0	—	—	2.0	—
Other	—	0.7	—	—	—	—	3.0	—	2.6
Total exploratory wells	2.8	1.7	—	6.0	2.0	—	7.0	5.0	9.6
Total drilling activity	128.8	41.3	—	69.3	8.9	1.0	225.0	90.8	17.6
Recompletions/refractures	29.3			30.6			106.9		

Strategically Acquire

Our acquisition efforts focus on producing properties that have a significant undeveloped acreage component. When weighing potential acquisitions, we prefer properties that have value in producing wells, behind-pipe reserves and high quality undeveloped drilling locations. In late 2009 and early 2010, we completed a U.S. onshore basin study that analyzed new areas where we could bring our skills and capital to crude oil and liquid rich fields that we believe can help deliver higher margins with scale and predictable drilling results. We plan to acquire properties through either direct acquisitions of the assets or acquisitions of entities owning the assets. We may also divest non-core assets as we seek to optimize our property portfolio. During 2011 and 2012, we expect to focus our resources on identifying and acquiring properties that have a high liquids component relative to its overall content.

Acquisitions in the Permian Basin. In July 2010, we acquired from an unrelated party 72 producing wells and 120 crude oil drilling locations located in the Wolfberry Trend in the Permian Basin in West Texas for $74.9 million. In November 2010, we acquired from an unrelated party 100% of the interest in additional producing assets and undeveloped acreage for $39.4 million. This second acquisition consisted of a primarily contiguous 5,760 net acre block with 122 identified crude oil drilling locations, based on 40-acre spacing.

Partnership Purchase Plan. In 2010, we initiated a plan to purchase our affiliated partnerships. The acquisition of these partnerships will provide us with immediate growth in both production and proved reserves from assets with which we are familiar. We believe that these acquisitions will also allow us to realize operational benefits and cost synergies as well as the opportunity to identify, pursue and accelerate a refracture program of the wells acquired. Pursuant to the plan, the following activity occurred in 2010.

- Acquisition of 2004 Partnerships. In December 2010, we acquired four affiliated partnerships: PDC 2004-A Limited Partnership, PDC 2004-B Limited Partnership, PDC 2004-C Limited Partnership and PDC 2004-D Limited Partnership. We purchased these partnerships for the aggregate amount of $34.8 million. These purchases included assets located in our core Wattenberg and Grand Valley Fields.

- Potential Acquisition of 2005 Partnerships. In November 2010, we announced that we were pursuing the purchase of three affiliated partnerships: PDC 2005-A Limited Partnership, PDC 2005-B Limited Partnership and Rockies Region Private Limited Partnership. The special meetings whereby investor partners of the 2005 partnerships will have an opportunity to vote and approve the applicable merger agreements are currently scheduled for March 25, 2011. We expect that if the required approvals are received from the investor partners at the special meetings and various other closing conditions are satisfied, each of the mergers for the 2005 partnerships will close no later than March 31, 2011. If all three 2005 partnerships are acquired, we will pay up to an aggregate of approximately $43.3 million for the limited partnership units of these partnerships. The assets in these 2005 partnerships are located in our core Wattenberg and Grand Valley Fields.

Divestiture of Michigan Assets. In July 2010, we divested our Michigan assets, consisting of primarily natural gas properties, and related liabilities for net cash proceeds of $22 million. We realized a loss on the sale of $4.7 million in the form of an impairment charge. Following the sale to an unrelated party, we do not have significant continuing involvement in the operations of or cash flows from this asset group; accordingly, the results of operations related to the Michigan assets have been separately reported as discontinued operations in the consolidated financial statements included in this report.

North Dakota Assets Held for Sale. During the fourth quarter of 2010, we developed a plan to divest and began marketing for sale our North Dakota assets. The assets include producing wells, undeveloped leaseholds and related facilities primarily located in Burke County. The plan received board approval and is expected to occur within one year of approval. In December 2010, we executed a letter of intent with an unrelated third party, which provides for the sale of 100% of our North Dakota assets. On February 7, 2011, we executed a purchase and sale agreement with the same unrelated party and we expect the transaction to close early March 2011. Following the sale to the unrelated party, we will not have significant continuing involvement in the operations of or cash flows from these assets; accordingly, the results of operations related to the North Dakota assets have been separately reported as discontinued operations in the consolidated financial statements included in this report.

Manage Operational and Financial Risk

Historically, we have concentrated on developmental drilling and geographical diversification to help reduce risk levels associated with natural gas and crude oil drilling, production and commodity markets. Currently, the majority of our proved reserves are located in the Rocky Mountain Region. However, we believe we benefit from operational diversity in the Rocky Mountain Region by maintaining significant activity and production in separate areas containing a balanced mix of natural gas and crude oil. These areas include our liquid rich Wattenberg Field, including the emerging Horizontal Niobrara crude oil play, located in the DJ Basin in north central Colorado and our Grand Valley gas field in the Piceance Basin in western Colorado. In addition, we recently entered the liquid-rich Permian Basin of West Texas where we are building a significant drilling inventory in the Wolfberry Trend. We regularly review opportunities to further diversify into other regions where we can apply our operational expertise. We believe developmental drilling will remain the foundation of our capital program because we believe it is less risky than exploratory drilling. Although we engage in limited exploratory drilling, we view our exploratory activities as having the potential to identify new development opportunities that provide long-term production and reserve growth. We believe our joint venture, PDCM, serves to mitigate the risks associated with exploring our Marcellus Shale acreage by sharing the cost of exploratory drilling activities with an investing partner.

We believe we maintain a conservative financial approach and proactively employ strategies to help reduce the risks associated with the oil and natural gas industry. We believe we maintain a conservative balance sheet, focusing on providing sufficient liquidity to execute our business strategy. In addition, we utilize commodity-based derivative instruments to manage a portion of our exposure to price volatility with regard to our natural gas and crude oil sales and natural gas marketing. We utilize both financial and physical derivative instruments. The financial instruments generally consist of floors, collars, swaps and basis swaps and consist of NYMEX, CIG and PEPL-based contracts. We may utilize derivatives based on other indices or markets where appropriate. The contracts economically provide price stability for committed and anticipated natural gas and crude oil sales and purchases, generally forecasted to occur within the next two to four-year period. Our policies prohibit the use of commodity derivatives for speculative purposes and permit utilization of derivatives only if there is an underlying physical position. As of December 31, 2010, we had natural gas and crude oil derivative positions in place for 2011 covering 52.8% of our expected natural gas production and 51.3% of our expected crude oil production.

Riley Natural Gas ("RNG"), a wholly owned subsidiary, uses financial derivatives in its gas marketing operations to coordinate fixed purchases and sales. RNG also enters into back-to-back fixed-price physical purchases and sales contracts with counterparties. RNG does not always hedge the area basis risk for third party trades with back-to-back fixed price purchases and sales. We continue to evaluate the potential for reducing this risk by entering into derivative transactions. Further, we may choose to close out any portion of a derivative contract existing at any time, which may result in a realized gain or loss on that derivative transaction.

Business Segments

We divide our operating activities into two segments: natural gas and crude oil sales and natural gas marketing.

Natural Gas and Crude Oil Sales

Commodity sales. Our natural gas and crude oil sales segment primarily reflects revenues and expenses from the production and sale of natural gas, NGLs and crude oil. We sell our natural gas and NGLs to other gas marketers, utilities, industrial end-users and other wholesale gas purchasers. We generally sell the natural gas that we produce under contracts with indexed monthly pricing provisions. Virtually all of our contracts include provisions wherein prices change monthly with changes in the market, for which certain adjustments may be made based on whether a well delivers to a gathering or transmission line, quality of natural gas and prevailing supply and demand conditions. Therefore, 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, holding production volume constant, increase as market prices increase and decrease as market prices decline. We believe that the pricing provisions of our natural gas contracts are customary in the industry. We also enter into financial derivatives in order to reduce the impact of possible price volatility regarding the physical sales market. See Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations: Results of Operations – Commodity Price Risk Management, Net, Natural Gas and Crude Oil Derivative Activities and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

Our wells in the Permian Basin and our Wattenberg Field produce crude oil and condensate as well as natural gas and NGLs. We do not refine any of our crude oil production. Our Wattenberg crude oil production is sold to purchasers at or near our wells under both short and long-term purchase contracts with monthly pricing provisions. Our Permian crude oil production is transported through our own and third party gathering systems and pipelines to move our crude oil from the wellhead to a purchaser-specified delivery point.

Well operations and pipeline services. In addition to commodity sales, our natural gas and crude oil sales segment includes revenues and expenses related to well operations and pipeline services. As of December 31, 2010, we had an interest in 5,048 wells. 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. As we are successful in our partnership acquisition program, revenues related to well operations and pipeline services will decrease.

We develop, own and operate gathering systems in some of our areas of operations. 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.

Our natural gas, NGLs and crude oil are transported through our own and third party gathering systems and pipelines, and we incur processing, gathering and transportation expenses to move our natural gas from the wellhead to a purchaser-specified delivery point. These expenses vary based on the volume and distance shipped, and the fee charged by the third-party processor or transporter. Capacity on these gathering systems and pipelines is occasionally limited and at times unavailable because of repairs or improvements, or as a result of priority transportation agreements with other gas transporters. While our ability to market our natural gas has been only infrequently limited or delayed, if transportation space is restricted or is unavailable, our cash flow from the affected properties could be adversely affected. In certain instances, we enter into firm transportation agreements to provide for pipeline capacity to flow and sell a portion of our gas volumes. In order to meet pipeline specifications, we are required, in some cases, to process our gas before we can transport it. We typically contract with third parties in the Grand Valley and NECO areas of our Rocky Mountain Region and Appalachian Basin for firm transportation of our natural gas. We also may enter into firm sales agreements to ensure that we are selling to a purchaser who has contracted for pipeline capacity. These agreements are subject to the same limitations discussed above in this paragraph. See Note 11, Commitments and Contingencies - Firm Transportation Agreements, to our consolidated financial statements included in this report for our long-term firm sales, processing and transportation agreements for pipeline capacity.

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations, Summary Operating Results, for production, sales, prices and lifting cost data for each of the years in the three-year period ended December 31, 2010.

Natural Gas Marketing

Our natural gas marketing segment is comprised of RNG. RNG specializes in the purchase, aggregation and sale of natural gas production in our Appalachian Basin. RNG purchases for resale natural gas produced by third party producers as well as natural gas produced by us, PDCM and our affiliated partnerships. The gas is marketed to third party marketers, natural gas utilities, as well as industrial and commercial customers, either directly through our gathering system, or through transportation services provided by regulated interstate pipeline companies.

For additional information regarding our business segments, see Note 17, Business Segments, to our consolidated financial statements included in this report.

Areas of Operations

The following map presents the general locations of our development, production and exploration activities as of December 31, 2010. We focus our development, production and exploration efforts primarily in three geographic areas of the U.S.: the Rocky Mountain Region, the Permian Basin of West Texas and, through our joint venture, the Appalachian Basin.

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Rocky Mountain Region

Our primary focus in the Rocky Mountain Region is on developmental drilling. We divide our Rocky Mountain Region into two major operating areas: the Wattenberg and Grand Valley Fields.

- Wattenberg Field, DJ Basin, Weld County, Colorado. Wells drilled in this area have historically been vertical and range from approximately 7,000 to 8,000 feet in depth. These wells targeted reservoirs in the Codell and Niobrara formations that have historically contained about 50% crude oil and NGLs. In October 2010, we began a horizontal drilling program targeting the liquid rich play of the Niobrara shale. Operations in the area, in addition to developmental drilling, include a program of refracturing existing wells in the Codell and Niobrara reservoirs. Well spacing ranges from 20 to 40 acres per well.

- Grand Valley Field, Piceance Basin, Garfield County, Colorado. The majority of the development wells drilled in this area are drilled directionally from multi-well pads and generally range from two to ten wells per drilling pad. Wells range from 7,000 to 9,500 feet in depth and primarily target natural gas reserves developed from multiple sandstone reservoirs in the Mesaverde Williams Fork formation. Well spacing is approximately ten acres per well.

Permian Basin

We entered the Permian Basin through an acquisition in July 2010 and further added to our position in November 2010. Operating activities in this area focus on developmental drilling for crude oil from the Wolfberry Trend, which combines the Spraberry and Wolfcamp formations. Our Permian Basin assets also produce from additional long-life formations, including the Strawn, Fusselman and Ellenberger formations, where we have initiated production optimization and recompletion programs.

Appalachian Basin

In October 2009, through our contribution of the majority of our Appalachian Basin assets, consisting of acreage, producing properties and related reserves, gathering assets and equipment, and a cash contribution by Lime Rock Partners, LP, we formed the joint venture PDCM. The producing properties we contributed included developmental wells producing from the shallow Devonian and Mississippian aged tight sandstone reservoirs. PDCM focuses primarily on exploratory drilling, targeting the Marcellus Shale formation in West Virginia. In 2010, through our joint venture, we drilled five horizontal Marcellus Shale wells to total depth, with three of them currently producing to pipeline, and began drilling a sixth well.

In addition to wells owned through our joint venture, we own an interest in approximately 271 gross, 88.5 net, natural gas and crude oil wells in West Virginia, Pennsylvania and Tennessee.

Properties

Productive Wells

The table below presents our productive wells by operating area at December 31, 2010.

	Productive Wells As of December 31, 2010					
	Natural Gas		Crude Oil		Total	
Location	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region						
Wattenberg Field	1,627	1,175.3	25	19.3	1,652	1,194.6
Grand Valley Field	331	231.7	—	—	331	231.7
Other	717	501.8	12	4.4	729	506.2
Total Rocky Mountain Region	2,675	1,908.8	37	23.7	2,712	1,932.5
Permian Basin	—	—	74	71.4	74	71.4
Appalachian Basin	2,217	965.4	39	15.5	2,256	980.9
Other	6	5.7	—	—	6	5.7
Total productive wells	4,898	2,879.9	150	110.6	5,048	2,990.5

Proved Reserves

All of our proved reserves are located in the U.S. Our reserve estimates are prepared with respect to reserve categorization, using the definitions for proved reserves set forth in SEC Regulation S-X, Rule 4-10(a) and subsequent SEC staff regulations, interpretations and guidance. Substantially all of our proved reserves, including reserves held by consolidated companies and our proportionate share of PDCM and our affiliated partnerships, have been estimated by independent engineers. For our Appalachian Basin reserves, our internal reserve engineers estimated approximately three percent of the total proved developed natural gas reserves and approximately one percent of total proved undeveloped natural gas reserves.

We have a comprehensive process that governs the determination and reporting of our proved reserves. As part of our internal control process, our reserves are reviewed annually by an internal team composed of reservoir engineers, geologists and accounting personnel for adherence to SEC guidelines through a detailed review of land records, available geological and reservoir data as well as production performance data. The review includes, but is not limited to, confirmation that reserve estimates (1) include all properties owned, (2) are based on proper working and net revenue interests, and (3) reflect reasonable cost estimates and field performance. The internal team compiles the reviewed data and forwards the data to an independent engineering firm engaged to estimate our reserves.

Our reserve estimates as of December 31, 2010, were substantially based on reserve reports prepared by Ryder Scott Company, L.P. ("Ryder Scott"); approximately three percent of the total proved developed natural gas reserves and approximately one percent of total proved undeveloped natural gas reserves were based on reserve estimates prepared by our internal engineering team. For each of the years in the two-year period ended December 31, 2009, our reserve estimates for the Rocky Mountain Region and Fort Worth Basin were prepared by Ryder Scott and our reserve estimates for the Appalachian and Michigan Basins were based on reserve reports prepared by Wright & Company. 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, production volumes, well test data, historical costs of operations and development, product prices, or any agreements relating to current and future operations of properties and sales of production.

The independent petroleum engineers prepare an estimate of our reserves in conjunction with an ongoing review by our engineers. A final comparison of data is performed to ensure that the reserve estimates are complete, determined by acceptable industry methods and to a level of detail we deem appropriate. The final independent petroleum engineers' estimated reserve reports are reviewed and approved by our engineering staff and management.

The professional qualifications of the lead engineer primarily responsible for overseeing the preparation of our reserve estimates meet the standards of Reserves Estimator as defined in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information as promulgated by the Society of Petroleum Engineers. This employee holds a Bachelor of Science degree in Petroleum and Natural Gas Engineering and has over 25 years of experience in reservoir engineering. The individual is a member of the Society of Petroleum Engineers, allowing the individual to remain current with developments and trends in the industry. Further, during 2009, this individual attended ten hours of formalized training relating to the definitions and disclosure guidelines set forth in the SEC's final rule released January 2009, Modernization of Oil and Gas Reporting.

The tables below present information regarding our estimated proved reserves. Reserves cannot be measured exactly, because reserve estimates involve judgments. The estimates must be reviewed periodically and adjusted to reflect additional information gained from reservoir performance, new geological and geophysical data and economic changes. Neither the estimated future net cash flows nor the standardized measure is intended to represent the current market value of our proved reserves. For additional information regarding both of these measures, as well as other information regarding our proved reserves, see the Natural Gas and Crude Oil Information section of the supplemental information provided with our consolidated financial statements included in this report.

	As of December 31,		
	2010	2009	2008
Proved reserves			
Natural gas (MMcf)	657,306	608,925	662,857
Crude Oil, Condensate and NGLs (MBbls) (1)	33,885	18,070	15,037
Total proved reserves (MMcfe)	860,616	717,345	753,079
Proved developed reserves (MMcfe)	301,141	295,839	329,669
Estimated future net cash flows (in thousands) (2)	$1,314,642	$764,111	$1,056,890
Standardized measure (in thousands) (2)(3)	$488,418	$347,636	$356,805

(1) Prior to 2010, NGLs were included in natural gas, which impacts comparability for 2010 to 2009 and 2008. In 2010, NGLs represented 7.4% of total proved reserves.

(2) Estimated future net cash flow represents the undiscounted 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. Prices used to estimate future gross revenues and production and development costs were based on the following:

- Gross revenues
- For 2010 and 2009, a 12-month average price calculated as the unweighted arithmetic average of the prices on the first day of each month, January through December; for 2008, prices in effect as of December 31, 2008.
- Prices for each of the three years were adjusted by field for Btu content, transportation and regional price differences; however, they were not adjusted to reflect the value of our commodity hedges.
- Production and development costs
- Prices as of December 31 for each of the respective years presented.
- The amounts shown do not give effect to non-property related expenses, such as corporate general and administrative expenses, debt service, or to depreciation, depletion and amortization expense.

(3) The standardized measure of discounted future net cash flow represents the present value of estimated future net cash flows discounted at a rate of 10% per annum to reflect timing of future cash flows.

	As of December 31, 2010				
	Natural Gas (MMcf)	Crude Oil, Condensate and NGLs (MBbls)	Natural Gas Equivalent (MMcfe)	Percent	
Proved developed					
Rocky Mountain Region					
Wattenberg Field	52,487	10,298	114,275	38	%
Grand Valley Field	106,260	244	107,724	36	%
Other	35,525	287	37,247	12	%
Total Rocky Mountain Region	194,272	10,829	259,246	86	%
Permian Basin	2,854	1,427	11,416	4	%
Appalachian Basin	30,081	44	30,345	10	%
Other	134	—	134	—	%
Total proved developed	227,341	12,300	301,141	100	%
Proved undeveloped					
Rocky Mountain Region					
Wattenberg Field	79,259	18,187	188,381	34	%
Grand Valley Field	304,343	304	306,167	55	%
Other	9,058	—	9,058	1	%
Total Rocky Mountain Region	392,660	18,491	503,606	90	%
Permian Basin	2,125	3,094	20,689	4	%
Appalachian Basin	35,180	—	35,180	6	%
Total proved undeveloped	429,965	21,585	559,475	100	%
Proved reserves					
Rocky Mountain Region					
Wattenberg Field	131,746	28,485	302,656	35	%
Grand Valley Field (1)	410,603	548	413,891	48	%
Other	44,583	287	46,305	5	%
Total Rocky Mountain Region	586,932	29,320	762,852	88	%
Permian Basin	4,979	4,521	32,105	4	%
Appalachian Basin	65,261	44	65,525	8	%
Other	134	—	134	—	%
Total proved reserves	657,306	33,885	860,616	100	%

(1) Two leases in our Grand Valley Field represent 48% of our total proved reserves.

Substantially all of our natural gas and crude oil properties, exclusive of properties held by PDCM, have been mortgaged or pledged as security for our credit facility. Substantially all of PDCM's properties have been pledged as collateral for the joint venture's credit facility. See Note 4, Derivative Financial Instruments, and Note 8, Long-Term Debt, to our consolidated financial statements included in this report.

Developed and Undeveloped Acreage

The following table presents, by operating area, leased acres as of December 31, 2010.

As of December 31, 2010		
Developed	Undeveloped (1)	Total

Location	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain Region						
Wattenberg Field	49,900	48,300	33,600	25,200	83,500	73,500
Grand Valley Field	2,900	2,900	5,100	5,100	8,000	8,000
Other	32,520	24,400	164,400	107,700	196,920	132,100
Total Rocky Mountain Region	85,320	75,600	203,100	138,000	288,420	213,600
Permian Basin	6,900	6,400	6,600	6,400	13,500	12,800
Appalachian Basin	53,900	53,200	9,500	8,600	63,400	61,800
Other	400	400	17,300	14,100	17,700	14,500
Total acreage	146,520	135,600	236,500	167,100	383,020	302,700

(1) Substantially all of our undeveloped acreage is related to leaseholds that are held by production. We have no material acreage with near term expiry, with the exception of 5,800 gross, 5,500 net, acres located in the Permian Basin, which expire during 2011. We have initiated a continuous drilling program in accordance with the terms of the leases, which will allow us to establish and hold by production those properties deemed prospective for commercial development.

Title to Properties

We believe that we hold good and defensible title to our developed properties, in accordance with standards generally accepted in the industry. As is customary in the industry, a preliminary title examination is conducted at the time the undeveloped properties are acquired. Prior to the commencement of drilling operations, a title examination is conducted and remedial 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.

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 crude 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.

Facilities

We lease 39,720 square feet in downtown Denver, Colorado, which serves as our corporate offices, through December 2015. We own a 32,000 square feet administrative office building located in Bridgeport, West Virginia, where we also lease approximately 17,700 square feet of office space in a second building through October 2011.

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

- Colorado: Evans, Parachute and Wray
- Pennsylvania: Indiana and Mahaffey
- Texas: Midland
- West Virginia: Bridgeport and Glenville

Governmental Regulation

While the prices of natural gas and crude oil are market driven, other aspects of our business and the industry in general are heavily regulated. The availability of a ready market for natural gas and crude oil 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 natural gas and crude oil available for sale, the availability of adequate pipeline and other transportation and processing facilities and the marketing of competitive fuels. State and federal regulations generally are intended to protect consumers from unfair treatment and oppressive control, to reduce the risk to the public and workers from the drilling, completion, production and transportation of natural gas and crude oil, to prevent waste of natural gas and crude oil, to protect rights among owners in a common reservoir and to control contamination of the environment. Pipelines are subject to the jurisdiction of various federal, state and local agencies. In the western part of the U.S., the federal and state governments own a large percentage of the land and the rights to develop natural gas and crude oil. Generally, government leases are subject to additional regulations and controls not commonly seen on private leases. We take the steps necessary to comply with applicable regulations, both on our own behalf and as part of the services we provide to our drilling partnerships. We believe that we are in compliance with such statutes, rules, regulations and governmental orders, although there can be no assurance that this is or will remain the case. The following summary discussion of the regulation of the U.S. oil and natural gas industry is not intended to constitute a complete discussion of the various statutes, rules, regulations and environmental orders to which our operations may be subject.

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

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

Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the density of wells which may be drilled and the unitization or pooling of properties. In this regard, some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely primarily or exclusively on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units, and therefore, more difficult to develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws may establish maximum rates of production from natural gas and crude oil 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 natural gas and crude oil we can produce from our wells and may limit the number of wells or the locations at which we can drill. Such laws and regulations may increase the costs of planning, designing, drilling, installing, operating and abandoning our natural gas and crude oil wells and other facilities. In addition, these laws and regulations, and any others that are passed by the jurisdictions where we have production, could limit the total number of wells drilled or the allowable production from successful wells, which could limit our reserves. As a result, we are unable to predict the future cost or effect of complying with such regulations.

Although we currently hold very little acreage under federal leases, if we wish to increase such holdings then our costs and timing will be increased due to the new Bureau of Land Management leasing policies announced in May 2010. These policies change, among other things, the required environmental review, including additional public input related to the proposed leases.

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

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

Each interstate natural gas pipeline company establishes its rates primarily through the FERC’s rate-making 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 industry. As a result of initiatives like FERC Order No. 636, issued in April 1992, the interstate natural gas transportation and marketing system was substantially restructured to remove various barriers and practices that historically limited non-pipeline natural gas sellers, including producers, from effectively competing with interstate pipelines for sales to local distribution companies and large industrial and commercial customers. The most significant provisions of Order No. 636 require that interstate pipelines provide transportation separate or "unbundled" from their sales service, and require that pipelines provide firm and interruptible transportation service on an open access basis that is equal for all natural gas suppliers. In many instances, the result of Order No. 636 and related initiatives has been to substantially reduce or eliminate the interstate pipelines' traditional role as wholesalers of natural gas in favor of providing only storage and transportation services. Another effect of regulatory restructuring is greater access to transportation on interstate pipelines. In some cases, producers and marketers have benefited from this availability. However, competition among suppliers has greatly increased and traditional long-term producer-pipeline contracts are rare. Furthermore, gathering facilities of interstate pipelines are no longer regulated by FERC, thus allowing gatherers to charge higher gathering rates. Historically, producers were able to flow supplies into interstate pipelines on an interruptible basis; however, recently we have seen the increased need to acquire firm transportation on pipelines in order to avoid curtailments or shut-in gas, which could adversely affect cash flows from the affected area.

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

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 is expected to 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 industry in general, our business and prospects could be adversely affected.

We generate wastes that may be subject to the Federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes. The U.S. Environmental Protection Agency, or EPA, and various state agencies have limited the approved methods of disposal for certain hazardous and non-hazardous wastes. Furthermore, certain wastes generated by our operations that are currently exempt from treatment as "hazardous wastes" may in the future be designated as "hazardous wastes," and therefore be subject to more rigorous and costly operating and disposal requirements.

We currently own or lease numerous properties that for many years have been used for the exploration and production of natural gas and crude oil. Although we believe that we have utilized good operating and waste disposal practices, and when necessary, appropriate remediation techniques, prior owners and operators of these properties may not have utilized similar practices and techniques, and hydrocarbons or other wastes may have been disposed of or released on or under the properties that we own or lease or on or under locations where such wastes have been taken for disposal. These properties and the wastes disposed thereon may be subject to the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, RCRA and analogous state laws, as well as state laws governing the management of natural gas and crude oil wastes. Under such laws, we could be required to remove or remediate previously disposed wastes (including wastes disposed of or released by prior owners or operators) or property contamination (including groundwater contamination) or to perform remedial plugging operations to prevent future contamination.

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

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

The Federal Clean Water Act, or CWA, and analogous state laws impose strict controls against the discharge of pollutants, including spills and leaks of crude oil and other substances. The CWA also regulates storm water run-off from natural gas and crude oil 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.

Crude 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 crude oil spills. Federal regulations require certain owners or operators of facilities that store or otherwise handle crude oil, including us, to procure and implement Spill Prevention, Control and Counter-measures plans relating to the possible discharge of crude 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 crude 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 crude oil discharge or crude oil spill problems. Our shift in production since mid-2010 to a greater percentage of crude oil also enhances our risks related to soil and water contamination.

In 2009, the State of Colorado's Oil and Gas Conservation Commission implemented new broad-based environmental and wildlife protection regulations for the industry. These regulations will continue to increase our costs and may ultimately limit some drilling locations. Our expenses relating to preserving the environment have risen over the past few years and are expected to continue to rise in 2011 and beyond. Environmental regulations have increased our costs and planning time, but have had no materially adverse effect on our ability to operate to date. However, no assurance can be given that environmental regulations or interpretations of such regulations will not, in the future, result in a curtailment of production or otherwise have a materially adverse effect on our business, financial condition or results of operations. See Note 11, Commitments and Contingencies – Litigation, Colorado Stormwater Permit, to our consolidated financial statements included in this report.

Operating Hazards and Insurance

Our exploration and production operations include a variety of operating risks, including, but not limited to, the risk of fire, explosions, blowouts, cratering, pipe failure, casing collapse, abnormally pressured formations, and environmental hazards such as gas leaks, ruptures and discharges of natural 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 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 natural gas and crude oil companies, drilling and income programs and partnerships in all areas of operations, including drilling and marketing natural gas and crude oil and obtaining desirable natural gas and crude oil leases on producing properties. Many of these competitors possess larger staffs and greater financial resources than we do, which may enable them to identify and acquire desirable producing properties and drilling prospects more economically. Our ability to explore for natural gas and crude oil prospects and to acquire additional properties in the future depends upon our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We also face intense competition in the marketing of natural gas from competitors including other producers as well as marketing companies. Also, international developments and the possible improved economics of domestic natural gas exploration may influence other companies to increase their domestic natural gas and crude oil exploration. Furthermore, competition among companies for favorable prospects can be expected to continue, and it is anticipated that the cost of acquiring properties may increase in the future.

In 2010, certain regions experienced strong demand for drilling services and supplies which resulted in increasing costs. Our Wattenberg Field, Permian Basin and especially our Appalachian Basin experienced intense competition to gain access to drilling and pumping services. For 2011, early signs indicate increased costs are likely, in particular in our Wattenberg Field. Factors affecting competition in the industry include price, location of drilling, availability of drilling prospects and drilling rigs, fracturing services, pipeline capacity, quality of production and volumes produced. We believe that we can compete effectively in the industry in each of the areas where we have operations. Nevertheless, our business, financial condition and results of operations could be materially adversely affected by competition. We also compete with other natural gas and crude oil companies as well as companies in other industries for the capital we need to conduct our operations. With all the turmoil in the 2008/2009 capital markets, financing was more expensive and more difficult to obtain. If 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, 2010, we had 327 employees, including 195 in production, 8 in natural gas marketing, 30 in exploration and development, 72 in finance, accounting and data processing and 22 in administration. Our employees are not covered by a collective bargaining agreement. We consider relations with our employees to be very good.

Our engineers, supervisors and well tenders are responsible for the day-to-day operation of wells and some pipeline systems. Much of the work associated with drilling, completing and connecting wells, including fracturing, logging and pipeline construction, is performed under our direction by subcontractors specializing in these activities as is common in the industry.

ITEM 1A. RISK FACTORS

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

Risks Related to the Domestic and Global Economic Environment

The current slow economic growth both domestically and globally may not improve or there may be a reoccurrence of the recent global economic recession, which increases the magnitude and the likelihood of the occurrence of the negative consequences discussed in many of the risks factors that follow.

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

The current slow economic growth both domestically and globally may not improve or there may be a reoccurrence of the disruptions during the recent recession in the global financial markets and the related economic environment may further decrease the demand for natural gas and crude oil and the prices of natural gas and crude oil, thereby limiting our future drilling and production, and thereby adversely affecting our financial condition and profitability.

The global financial market disruptions during the recent recession and the related economic environment resulted in a decrease in the demand for natural gas and crude oil and therefore lower natural gas and crude oil prices. For example, during the last six months of 2008, the prices for natural gas and crude oil decreased over 60% from the 2008 peak. If there is such an additional reduction in demand in the future, the continued production of gas may increase current oversupply and result in still lower gas prices. There is no certainty how long this low price environment would continue. We operate in a highly competitive industry, and certain competitors may have lower operating costs in such an environment. Furthermore, as a result of any such disruptions in the financial markets, it is possible that in future years we would not be able to borrow or otherwise raise sufficient funds to sustain or increase capital expenditures. Such market conditions may also make it more difficult or impossible for us to finance acquisitions, through either equity or debt; acquisitions have historically been a major source of growth for us. Consequently, we would be unable to expand our reserves, drilling operations and production. We may also have difficulty finding partners to develop new drilling prospects and to build the pipeline systems needed to transport our gas. Inability of third parties to finance and build additional pipelines out of the Rockies, the Marcellus and elsewhere could cause significant negative pricing effects. Any of the above factors could adversely affect our operating results.

Risks Related to Our Business and the Industry

Natural gas and crude oil prices fluctuate unpredictably and a decline in natural gas and crude 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 crude 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. For instance, in much of 2010, natural gas prices were too low to economically justify many drilling operations. Changes in natural gas and crude oil prices have a significant effect on our cash flow and on the value of our reserves, which can in turn reduce our borrowing base under our senior credit facility Prices for natural gas and crude oil may fluctuate widely in response to relatively minor changes in the supply of and demand for natural gas and crude 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. For example, any significant reduction in the growth rate of China could affect global oil prices significantly.

The prices of natural gas and crude oil are volatile, often fluctuating greatly. Lower natural gas and crude oil prices may not only reduce our revenues, but also may reduce the amount of natural gas and crude oil that we can produce economically. As a result, we may have to make substantial additional downward adjustments to our estimated proved reserves. If this occurs or if our estimates of development costs increase, production data factors change or our exploration results deteriorate, accounting rules may require us to write-down operating assets to fair value, as a non-cash charge to earnings. We assess impairment of capitalized costs of proved natural gas and crude 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 2010, in conjunction with our decision to divest our Michigan assets, we recorded a related impairment charge on proved natural gas and crude oil properties of $4.7 million and in 2008, we recorded impairment charges totaling $12.8 million, primarily related to our properties in the Fort Worth Basin and in North Dakota. 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 crude oil production is located in the Rocky Mountain Region, making it vulnerable to risks associated with operating primarily in a single geographic area.

Our operations have been focused on the Rocky Mountain Region, which means our current producing properties and new drilling opportunities are geographically concentrated in that area. Because our operations are not as diversified geographically as many of our competitors, the success of our operations and our profitability may be disproportionately exposed to the effect of any regional events, including fluctuations in prices of natural gas and crude 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. For example, the recent increase in activity in the Niobrara could lead to bottlenecks in processing that negatively affect our results disproportionately compared to our more geographically diverse competitors.

Prior to 2010, natural gas prices in the Rocky Mountain Region often fell disproportionately when compared to other markets, due in part to continuing constraints in transporting natural gas from producing properties in the region. Because of the concentration of our operations in the Rocky Mountain Region, 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. Although current natural gas prices in the Rocky Mountain Region are not steeply discounted to NYMEX, there can be no assurance as to such continuation.

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

Natural gas and crude oil reserve engineering requires subjective estimates of underground accumulations of natural gas and crude oil and assumptions concerning future natural gas and crude 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 crude 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 crude 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 crude oil attributable to any particular group of properties;
- future depreciation, depletion and amortization ("DD&A") rates and amounts;
- impairments in the value of our assets;
- the classifications of reserves based on risk of recovery;
- estimates of the future net cash flows;
- timing of our capital expenditures; and
- the amount of funds available for us to utilize under our revolving credit facility.

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 crude oil recovered being different from earlier reserve estimates.

The present value of our estimated future net cash flows from proved reserves is not necessarily the same as the current market value of our estimated natural gas and crude oil reserves. The estimated discounted future net cash flows from proved reserves were based on the 12-month average natural gas and crude oil index prices. However, factors such as actual prices we receive for natural gas and crude 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 crude oil, and changes in governmental regulations or taxation also affect our actual future net cash flows from our natural gas and crude oil properties.

The timing of both our production and incurrence of expenses in connection with the development and production of natural gas and crude 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 crude oil properties or the industry in general.

Unless natural gas and crude 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 crude oil reservoirs generally is characterized by declining production rates that vary depending upon reservoir characteristics and other factors. The rate of decline will change if production from existing wells declines in a different manner than we estimated and the rate can change due to other circumstances. Thus, our future natural gas and crude 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 crude 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 are generally consistent with industry practices. However, such reviews are not likely to permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well prior to an acquisition and our ability to evaluate undeveloped acreage is inherently imprecise. Even when we inspect a well, we may 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 crude 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. We often acquire interests in properties on an "as is" basis with no or limited remedies for breaches of representations and warranties. 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. We acquire interests in wells which we may need to operate together with other partners, and we acquire pipelines that we may need to operate and expect we may 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.

We may not be able to consummate additional prospective acquisitions of our drilling partnerships, which could adversely affect our business operations.

Consummation of future acquisitions of drilling partnerships, which is conditioned on a pricing agreement with the special committee of our board of directors, as well as customary closing conditions, which may not be satisfied or waived. In addition, consummation of the acquisition of partnerships requires approval by the holders of a majority of the limited partnership units held by the non-affiliated investors of each respective partnership. Furthermore, each of the partnerships must complete their SEC proxy disclosure review process and receive clearance from the SEC before the partnerships can request approval of the merger transactions from their non-affiliated investors. If we are unable to consummate all or a portion of these prospective acquisitions, we would not realize the expected benefits of the proposed acquisitions. In addition, we will have incurred, and will remain liable for, transaction costs, including legal, accounting, financial advisory and other costs relating to the prospective acquisitions, including the costs of the special committee of our board of directors, whether or not they are consummated. The occurrence of any of these events individually or in combination could have an adverse effect on our business, financial condition and results of operations.

Any acquisitions we complete, including the prospective acquisitions, are subject to substantial risks that could adversely affect our financial condition and results of operations.

Even if we complete the prospective acquisitions, integration of the prospective acquisitions may be difficult. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, future commodity prices, revenues, capital expenditures and operating costs, including synergies;
- an inability to integrate the businesses we acquire successfully;
- a decrease in our liquidity by using a portion of our available cash or borrowing capacity under our revolving credit facility to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs, including those that are environmental, for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management’s attention from other business concerns;
- natural disasters;
- the incurrence of other significant charges, such as impairment of natural gas and crude oil properties,

goodwill or other intangible assets, asset devaluation or restructuring charges;

- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

When drilling prospects, we may not yield natural gas or crude 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 crude oil bearing rocks. However, our geologists cannot know conclusively prior to drilling and testing whether natural gas or crude oil will be present or, if present, whether natural gas or crude 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 natural gas or crude oil, 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 crude 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 and acquire enough attractive prospects on a timely basis to meet our development needs, which could limit our future development opportunities and adversely affect our profitability.

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 crude 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 crude 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 crude oil can be unprofitable, not only due to dry holes, but also due to curtailments, delays or cancellations as a result of other factors, including:

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

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

Our hydrocarbon drilling, transportation and processing activities are subject to a range of applicable federal, state and local laws and regulations. A loss of containment of hydrocarbons during these activities could potentially subject us to civil and/or criminal liability and the possibility of substantial costs, including environmental remediation, depending upon the circumstances of the loss of containment, the nature and scope of the loss and the applicable laws and regulations. We are currently involved in various remedial and investigatory activities at some of our wells and related sites. See Note 11, Commitments and Contingencies - Environmental, to our consolidated financial statements included in this report.

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

We have conducted exploratory drilling and plan to continue exploratory drilling in 2011 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 have a negative effect on our debt covenants.

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 DD&A 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 crude 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 crude oil properties has become extremely competitive among producers for additional production and expanded drilling opportunities in North America. Acquisition values for crude oil properties climbed in 2010 and these values may continue to increase in the future. This increase in finding and development costs results in higher DD&A rates. If the upward trend in crude oil finding and development costs continues, we will be exposed to an increased likelihood of a write-down in carrying value of our crude oil properties in response to any future 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 crude oil reserves, and ultimately our profitability.

Our industry is capital intensive. We expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of natural gas and crude oil reserves. To date, we have financed capital expenditures primarily with bank borrowings under our credit facility, cash generated by operations and capital markets, through the sale of equity and the issuance of debt securities. We intend to finance our future capital expenditures utilizing similar financing sources. Our cash flows from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the amount of natural gas and crude oil we are able to produce from existing wells;
- the prices at which natural gas and crude oil are sold;
- the costs to produce natural gas and crude oil; 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 crude 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. Our inability to obtain additional financing, or sufficient financing on favorable terms, would adversely affect our financial condition and profitability.

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

If additional capital is needed, we may not be able to obtain debt or equity financing on favorable terms, or at all. If cash generated by our operations or 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 crude oil reserves and production and a decline in our profitability.

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

Seasonal weather conditions and lease stipulations designed to protect various wildlife affect natural gas and crude oil operations in the Rocky Mountains. In certain areas, including parts of the Piceance Basin in Colorado, drilling and other natural gas and crude 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 additional or increased costs or periodic shortages. These constraints and the resulting high costs or shortages 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 approximately 93% of the wells in which we own an interest. 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 by an operator to adequately perform operations, or an operator’s breach of the applicable agreements, could reduce production and revenues and adversely 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 crude oil markets or delay production and thereby adversely affect our profitability.

Market conditions or the unavailability of satisfactory natural gas and crude oil transportation arrangements may hinder our access to natural gas and crude oil markets or delay our production. The availability of a ready market for natural gas and crude oil production depends on a number of factors, including the demand for and supply of natural gas and crude 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 the lack of a market or because of inadequacy, unavailability or the pricing associated with natural gas pipelines, gathering system capacity or processing facilities. If that were to occur, we would be unable to realize revenue from those wells until we made production arrangements to deliver the product to market. Thus, our profitability would be adversely affected.

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

We use derivatives for a portion of our natural gas and crude 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 crude 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 increases in the prices for natural gas and crude oil. They may also require the use of our resources to meet cash margin requirements. Since we do not designate our derivatives as hedges, we do not currently qualify for use of hedge accounting; therefore, changes in the fair value of derivatives are recorded in our income statements, and our net income is subject to greater volatility than if our derivative instruments qualified for hedge accounting. For instance, if natural gas and crude oil prices rise significantly, it could result in significant non-cash charges each quarter, which could have a material negative effect on our net income.

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

Substantially all of our accounts receivable result from our natural gas, NGL and crude 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 crude oil derivatives as well as the derivatives used by our marketing subsidiary expose us to credit risk in the event of nonperformance by counterparties. Nonperformance by our customers may adversely affect our financial condition and profitability.

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 crude 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 or in excess of our insurance coverage 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. We do not carry contingent business interruption insurance related to the processing plants owned by our natural gas purchasers or oil refineries owned by our crude oil purchasers. For some risks, such as drilling blow-out insurance, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks that we are subject to are generally not fully insurable.

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

Our 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 or other new technologies at substantial cost. In addition, other natural gas and crude 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 our industry is intense, which may adversely affect our ability to succeed.

Our 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 crude 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 crude 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 crude 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 crude oil properties. These factors could adversely affect the success of our operations and our profitability.

Anti-oil and gas industry sentiment has increased. The current trend is to increase regulation of our operations and the industry. 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 crude 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 of conservation practices and protection of correlative rights by state governments. These regulations affect our operations, increase our costs of exploration and production and limit the quantity of natural gas and crude 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 crude 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 this trend are the regulations implemented in 2009 by the State of Colorado, which focus on the industry. These multi-faceted regulations significantly enhance requirements regarding natural gas and crude oil permitting, environmental requirements and wildlife protection. Permitting delays and increased costs could result from these final regulations.

The BP crude oil spill in the Gulf of Mexico and anti-industry sentiment may result in new state and federal safety and environmental laws, regulations, guidelines and enforcement interpretations. Although we have no operations in the Gulf of Mexico, this incident could result in regulatory initiatives in other areas as well that could limit our ability to drill wells and increase our costs of exploration and production. Furthermore, the U.S. Environmental Protection Agency ("EPA") has recently focused on citizen concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities, including public meetings around the country on this issue which have been well publicized and well attended. This renewed focus could lead to additional federal and state laws and regulations affecting our drilling, fracturing and operations. Additional laws, regulations or other changes could significantly reduce our future growth, increase our costs of operations, and reduce our cash flow, in addition to undermining the demand for the natural gas and crude oil we produce.

Other potential laws and regulations affecting us include new or increased severance taxes proposed in several states, including Pennsylvania. This could adversely affect the existing operations in these states and the economic viability of future drilling. Additional laws, regulations or other changes could significantly reduce our future growth, increase our costs of operations and reduce our cash flow, in addition to undermining the demand for the natural gas and crude oil we produce.

Certain federal income tax deductions currently available with respect to natural gas and crude oil and exploration and development may be eliminated as a result of future legislation.

In February 2009, U.S. President Barack Obama ("President Obama") and his administration (the "Obama administration"), released its budget proposals for the fiscal year 2010, which included numerous proposed tax changes. In April 2009, legislation was introduced to further these objectives, and in February 2010, the Obama administration released similar budget proposals for the fiscal year 2011. Although these proposals were not enacted, the changes contained in the budget proposals included the elimination of certain key U.S. federal income tax preferences currently available to natural gas and crude oil exploration and production. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for natural gas and crude oil properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is not possible at this time to predict how legislation or new regulations that may be adopted to address these proposals would impact our business, but any such future laws and regulations could negatively affect our financial condition and results of operation.

New derivatives legislation and regulation could adversely affect our ability to hedge natural gas and crude oil prices and increase our costs and adversely affect our profitability.

In July 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd-Frank Act”). The Dodd-Frank Act regulates derivative transactions, including our natural gas and crude oil hedging swaps (swaps are broadly defined to include most of our hedging instruments). The new law requires the issuance of new regulations and administrative procedures related to derivatives within one year. The effect of such future regulations on our business is currently uncertain. In particular, note the following:

- The Dodd-Frank Act may decrease our ability to enter into hedging transactions which would expose us to additional risks related to commodity price volatility; commodity price decreases would then have an immediate significant adverse affect on our profitability and revenues. Reduced hedging may also impair our ability to have certainty with respect to a portion of our cash flow, which could lead to decreases in capital spending and, therefore, decreases in future production and reserves.
- We expect that the cost to hedge will increase as a result of fewer counterparties in the market and the pass-through of increased counterparty costs, thereby increasing the costs of derivative instruments. Our derivatives counterparties may be subject to significant new capital, margin and business conduct requirements imposed as a result of the new legislation.
- The Dodd-Frank Act contemplates that most swaps will be required to be cleared through a registered clearing facility and traded on a designated exchange or swap execution facility. There are some exceptions to these requirements for entities that use swaps to hedge or mitigate commercial risk. While we may ultimately be eligible for such exceptions, the scope of these exceptions currently is somewhat uncertain, pending further definition through rulemaking proceedings.
- The above factors could also affect the pricing of derivatives and make it more difficult for us to enter into hedging transactions on favorable terms.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the natural gas and crude oil that we produce while physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In December 2009, the EPA, published its findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth’s atmosphere and other climatic changes. These findings allow the EPA to adopt and implement regulations that would restrict emissions of greenhouse gases under existing provisions of the Federal Clean Air Act. In June 2010, the EPA published its final rule to address the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD"), and Title V permitting programs. This rule “tailors” these permitting programs to apply to certain stationary sources of greenhouse gas emissions in a multi-step process, with the largest sources first subject to permitting. It is widely expected that facilities required to obtain PSD permits for their greenhouse gas emissions will be required to also reduce those emissions according to “best available control technology,” or BACT, standards. In its permitting guidance for greenhouse gases, issued on November 10, 2010, the EPA has recommended options for BACT, which include improved energy efficiency, among others. Any regulatory or permitting obligation that limits emissions of greenhouse gases could require us to incur costs to reduce emissions of greenhouse gases associated with our operations and also adversely affect demand for the natural gas and crude oil that we produce.

In addition, in October 2009, the EPA published a final rule requiring the reporting of greenhouse gas emissions from specified large greenhouse gas sources in the U.S. on an annual basis, beginning in 2011 for emissions occurring after January 1, 2010. On November 8, 2010, the EPA finalized rules to expand its greenhouse gas reporting rule to include onshore natural gas and crude oil production, processing, transmission, storage and distribution facilities. Reporting of greenhouse gas emissions from such facilities will be required on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011.

In June 2009, the U.S. House of Representatives passed the American Clean Energy and Security Act of 2009 ("ACESA"), which would establish an economy-wide cap on emissions of greenhouse gases in the U.S. and would require most sources of greenhouse gas emissions to obtain and hold “allowances” corresponding to their annual emissions of greenhouse gases. By steadily reducing the number of available allowances over time, ACESA would require a 17 percent reduction in greenhouse gas emissions from 2005 levels by 2020, increasing up to an 83 percent reduction of such emissions by 2050. Many states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. The passage of legislation that limits emissions of greenhouse gases from our equipment and operations could require us to incur costs to reduce the greenhouse gas emissions from our operations, and it could also adversely affect demand for the natural gas and crude oil that we produce.

Some have suggested that one consequence of climate change could be increased severity of extreme weather, such as increased hurricanes and floods. If such effects were to occur, our operations could be adversely affected in various ways, including damages to our facilities from powerful winds or increased costs for insurance.

Another possible consequence of climate change is increased volatility in seasonal temperatures. The market for natural gas is generally improved by periods of colder weather and impaired by periods of warmer weather, so any changes in climate could affect the market for the fuels that we produce. Despite the use of the term “global warming” as a shorthand for climate change, some studies indicate
that climate change could cause some areas to experience temperatures substantially colder than their historical averages. As a result, it is difficult to predict how the market for our fuels could be affected by increased temperature volatility, although if there is an overall trend of warmer temperatures, it would be expected to have an adverse effect on our business.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays in the production of natural gas and crude oil, including from the development of shale plays. A decline in the drilling of new wells and related servicing activities caused by these initiatives could adversely affect our financial position, results of operations and cash flows.

Most of our drilling uses hydraulic fracturing. Proposals have been introduced in the U.S. Congress to regulate hydraulic fracturing operations and related injection of fracturing fluids and propping agents used by the oil and natural gas industry in fracturing fluids under the federal Safe Drinking Water Act ("SDWA"), and to require the disclosure of chemicals used in the hydraulic fracturing process under the SDWA, Emergency Planning and Community Right-to-Know Act ("EPCRA"), or other laws. Hydraulic fracturing is an important and commonly used process in the completion of unconventional natural gas and crude oil wells in shale, coalbed and tight sand formations. Sponsors of these bills, which are currently being considered in the legislative process, including the House Energy and Commerce Committee and the Senate Environmental and Public Works Committee, have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies and otherwise cause adverse environmental impacts. The Chairman of the House Energy and Commerce Committee has initiated an investigation of the potential impacts of hydraulic fracturing, which has involved seeking information about fracturing activities and chemicals from certain companies in the oil and natural gas sector. The EPA has recently focused on citizen concerns about the risk of water contamination and public health problems from drilling and hydraulic fracturing activities, including public meetings around the country on this issue which have been well publicized and well attended. In March 2010, the EPA announced its intention to conduct a comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on water quality and public health. The initial results are expected in the fall of 2012.

Several states have also proposed additional disclosure concerning chemicals used in the process. New York has imposed a moratorium on hydraulic fracturing of horizontal wells pending additional environmental investigation by the state. Lawsuits have also been filed against unrelated third parties in Pennsylvania and New York alleging contamination of drinking water by hydraulic fracturing. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to natural gas and crude oil production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or lead us to incur increased operating costs in the production of natural gas and crude oil, including from the development of shale plays, or could make it more difficult to perform hydraulic fracturing. If these legislative and regulatory initiatives cause a material decrease in the drilling of new wells and in related servicing activities, our profitability could be materially impacted.

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

In recent years, litigation has commenced against us and other companies in our industry regarding royalty practices and payments in jurisdictions where we conduct business. For more information on the suits that currently relate to us, see Note 11, Commitments and Contingencies, to our consolidated financial statements included in this report. 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 and profitability.

Risks Associated with Our Indebtedness

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

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

The revolving credit facility limits the amounts we can borrow to a borrowing base amount, determined by the lenders in their sole discretion based upon projected revenues from the natural gas and crude 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 crude 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 and our financial results.

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

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

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

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

Our senior credit facility 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 facility will waive any failure to meet such ratios or tests.

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

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

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

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

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

Risks Associated with Our Joint Venture

PDC Mountaineer, LLC is dependent upon our equity partner (the “Investor”) and poses exit-related risks for us.

The board of managers of the joint venture consists of three representatives appointed by us and three representatives appointed by the Investor, each with equal voting power. The joint venture agreement generally requires the affirmative vote of a majority of the members of the board to approve an action, and we and the Investor may not always agree on the best course of action for the joint venture. If such a disagreement were to occur, we would not be able to cause the joint venture to take action that we believed to be in the best interests of the joint venture. Consequently, our best interests may not be advanced and our investment in the joint venture could be adversely affected. If there is a disagreement about a development plan and budget for the joint venture, the Investor is entitled to unilaterally suspend substantially all of the operations of the joint venture, which could have a material adverse impact on the results of operations of the joint venture and our investment. Such a suspension could last for up to two years, at which point either party could elect to dissolve the joint venture or to sell their ownership interests to a third party. The Investor is entitled to a preference with respect to liquidating distributions and proceeds from significant sales of ownership interests up to the amount of its contributed capital, which would diminish our returns if the value of the joint venture had declined at the time of the liquidation or sale.

After a “restricted period” which generally lasts for the four year years following the closing of the joint venture, the Investor can seek to sell its interest in the joint venture to a third party, subject to rights of first offer and refusal in favor of us. If we do not exercise those rights in a sale involving all of the Investor’s ownership interests, the Investor can exercise “drag-along” rights and compel us to sell all of our interests in the proposed transaction. Accordingly, if we possessed insufficient funds and were unable to obtain financing necessary to purchase the Investor’s interest under the rights of first offer and refusal, we may be required to sell our interest in the joint venture at a time when we may not wish to do so. Under these circumstances, our investment in the joint venture could be adversely affected.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

Information regarding our legal proceedings can be found in Note 11, Commitments and Contingencies – Litigation, to our consolidated financial statements included in this report.

ITEM 4. [RESERVED]

PART II

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

Our authorized capital stock consists of 100,000,000 shares of common stock, par value $0.01 per share. Our common stock is traded on the NASDAQ Global Select Market under the ticker symbol PETD. The following table presents the range of high and low sales prices for our common stock for each of the periods presented.

	Price Range	
	High	Low
January 1 - March 31, 2009	$27.91	$9.39
April 1 - June 30, 2009	20.63	11.21
July 1 - September 30, 2009	19.14	12.50
October 1 - December 31, 2009	21.87	16.06
January 1 - March 31, 2010	25.37	18.11
April 1 - June 30, 2010	27.73	17.92
July 1 - September 30, 2010	30.39	23.82
October 1 - December 31, 2010	43.01	27.44

As of February 11, 2011, we had approximately 944 shareholders of record.

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

The following table presents information about our purchases of our common stock during the three months ended December 31, 2010.

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 - 31, 2010	724	$31.26	—	—
November 1 - 30, 2010	3,207	34.57	—	—
December 1 - 31, 2010	1,474	42.25	—	—
Total fourth quarter purchases	5,405	36.22		

(1) Purchases represent shares purchased pursuant to our stock-based compensation plans for payment of tax liabilities related to the vesting of securities.

SHAREHOLDER PERFORMANCE GRAPH

The performance graph below compares the cumulative total return of our common stock over the five-year period ended December 31, 2010, with the cumulative total returns for the same period for the Standard and Poor's ("S&P") 500 Index and the Standard Industrial Code ("SIC") Index. The SIC Index is a weighted composite of 175 crude petroleum and natural gas companies. The results shown in the graph below are not necessarily indicative of future performance.

(1) The cumulative total shareholder return assumes that $100 was invested, including reinvestment of dividends, if any, in our common stock on December 31, 2005, and in the S&P 500 Index and the SIC Index on the same date.

ITEM 6. SELECTED FINANCIAL DATA

	Year Ended December 31,				
	2010	2009	2008	2007 (3)	2006 (3)
	(in thousands, except per share data and as noted)				
Statement of Operations					
Natural gas, NGL and crude oil sales	$209,644	$171,242	$304,867	$175,187	$115,189
Commodity price risk management gain (loss), net (1)	59,891	(10,053)	127,838	2,756	9,147
Total revenues	347,647	230,876	572,501	291,737	267,237
Income (loss) from continuing operations	6,921	(80,118)	105,831	26,085	233,102
Earnings (loss) per share attributable to shareholders:					
Net income (loss) attributable to shareholders - basic	$0.32	$(4.82)	$7.69	$2.25	$15.18
Net income (loss) attributable to shareholders - diluted	$0.31	$(4.82)	$7.63	$2.24	$15.11
Statement of Cash Flows					
Net cash provided by operating activities	$151,813	$143,895	$139,101	$60,304	$67,390
Capital expenditures	162,723	143,033	323,153	238,988	146,180
Acquisitions	158,051	—	—	255,661	18,512
Balance Sheet					
Total assets	$1,389,035	$1,250,327	$1,402,704	$1,050,479	$884,287
Working capital (deficit)	16,194	32,936	31,266	(50,212)	29,180
Long-term debt	295,695	280,657	394,867	235,000	117,000
Equity	642,241	538,593	512,275	396,285	360,144
Production, Pricing, and Lifting Costs					
Total production (Bcfe)	37.6	41.6	36.9	28.0	16.9
Average sales price (excluding gains/losses on derivatives) (per Mcfe)	$5.67	$4.19	$8.37	$6.26	$6.80
Average sales price (including gains/losses on derivatives) (per Mcfe)	$6.92	$6.77	$8.62	$6.52	$6.91
Average lifting cost (per Mcfe) (2)	$1.11	$0.81	$1.08	$0.90	$0.76
Total proved reserves (Bcfe)	860.6	717.3	753.1	685.6	322.7

(1) See Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report.

(2) Lifting costs represent lease operating expenses, excluding production taxes, on a per unit basis.

(3) The years ended 2007 and 2006 do not present the effects of the divestitures of our Michigan and North Dakota assets as discontinued operations as the amounts related to these operations were immaterial to these years.

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

The following discussion and analysis, as well as other sections in this report, should be read in conjunction with our consolidated financial statements and related notes to consolidated financial statements included in this report. Further, we encourage you to revisit Special Note Regarding Forward-Looking Statements on page 3 of this report.

Non-GAAP Financial Measures

We use "adjusted cash flow from operations," "adjusted net income (loss) attributable to shareholders" and "adjusted EBITDA," non-GAAP financial measures, for internal managerial purposes, when evaluating period-to-period comparisons and providing public guidance on possible future results. These measures are not measures of financial performance under U.S. GAAP and should be considered in addition to, not as a substitute for, cash flows from operations, investing, or financing activities, nor as a liquidity measure or indicator of cash flows reported in accordance with U.S. GAAP. The non-GAAP financial measures that we use may not be comparable to similarly titled measures reported by other companies. Also, in the future, we may disclose different non-GAAP financial measures in order to help our investors more meaningfully evaluate and compare our future results of operations to our previously reported results of operations. We strongly encourage investors to review our financial statements and publicly filed reports in their entirety and to not rely on any single financial measure. See Reconciliation of Non-GAAP Financial Measures below for a detailed description of these measures as well as a reconciliation of each to the nearest U.S. GAAP measure.

2010 Overview

In 2010, we committed our efforts to strengthen the structure of our business, by building a foundation that will support our operations for future growth. Production from continuing operations decreased by 9.5% compared to 2009, including the impact on comparability due to the recognition of NGL volumes separately from natural gas, which lessens the year-over-year decrease. We experienced a decrease in quarter-over-quarter production during the first half of the year, but achieved production growth in the third and fourth quarters, which we expect will be the trend in 2011 and beyond. The decrease in production in 2010 was a result of our conservative capital spending program in 2009 due to the unstable financial and commodity markets. Despite the decrease in production, our natural gas, NGL and crude oil sales revenue increased by $38.4 million due to improved pricing and our initiatives to increase crude oil and NGL production as a percentage of total production. The increase in crude oil and NGL production was the result of our increased investment in organic growth, primarily in our liquid-rich Wattenberg Field, and our more recent acquisitions in liquid-rich acreage in the Permian Basin. Our total 2010 revenues were also favorably impacted by realized derivative gains related to natural gas and crude oil sales of $47.1 million, which effectively resulted in a net realized price of $6.92 per Mcfe.

We closed 2010 with available liquidity of $356.9 million compared to $238.2 million at the end of 2009. Available liquidity is comprised of cash, cash equivalents and funds available under our credit facility. Capital markets strengthened during 2010 and as such, in November 2010, we recognized an opportunity to access the markets and did so through the sale of equity and the issuance of convertible debt, raising $247.5 million in capital. With our strong liquidity position, 2011 will be a year of increased capital spending, focused on organic growth in the liquid-rich areas of our Wattenberg Field and the Permian Basin along with the proposed acquisitions of our affiliated partnerships. We believe that, combined with our investment in 2010, our capital budget will grow our production from continuing operations by 19% in 2011, excluding any future acquisitions, while increasing the liquids portion of our production as a percentage of our total production and thereby benefiting from the crude oil to natural gas price differential.

Results of Operations

Summary Operating Results

The following table presents selected information regarding our operating results from continuing operations. Prior to 2010, NGLs were included in natural gas, which impacts the comparability for 2010 to 2009 and 2008.

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	Year Ended December 31,			Change	
	2010	2009	2008	2010-2009	2009-2008
	(dollars in thousands, except per unit data)				
Production (1)					
Natural gas (MMcf)	26,387.5	34,089.6	30,101.1	(22.6)%	13.3%
Crude oil (MBbls)	1,265.3	1,244.0	1,135.8	1.7%	9.5%
NGLs (MBbls)	601.2	—	—	*	*
Natural gas equivalent (MMcfe) (2)	37,586.6	41,553.4	36,915.6	(9.5)%	12.6%
Average MMcfe per day	103.0	113.8	100.9	(9.5)%	12.9%
Natural Gas, NGL and Crude Oil Sales					
Natural gas	$95,147	$105,449	$207,086	(9.8)%	(49.1)%
Crude oil	93,670	68,499	101,806	36.7%	(32.7)%
NGLs	24,079	—	—	*	*
Provision for underpayment of natural gas sales	(3,252)	(2,706)	(4,025)	20.2%	(32.8)%
Total natural gas, NGL and crude oil sales	$209,644	$171,242	$304,867	22.4%	(43.8)%
Realized Gain (Loss) on Derivatives, net (3)					
Natural gas	$40,024	$89,464	$12,632	(55.3)%	*
Crude oil	7,071	17,881	(3,145)	(60.5)%	*
Total realized gain on derivatives, net	$47,095	$107,345	$9,487	(56.1)%	*
Average Sales Price (excluding gain/loss on derivatives)					
Natural gas (per Mcf)	$3.61	$3.09	$6.88	16.8%	(55.1)%
Crude oil (per Bbl)	74.03	55.07	89.64	34.4%	(38.6)%
NGLs (per Bbl)	40.05	—	—	*	*
Natural gas equivalent (per Mcfe)	5.67	4.19	8.37	35.3%	(49.9)%
Average Sales Price (including gain/loss on derivatives)					
Natural gas (per Mcf)	$5.12	$5.72	$7.30	(10.4)%	(21.7)%
Crude oil (per Bbl)	79.62	69.44	86.86	14.7%	(20.1)%
NGLs (per Bbl)	40.05	—	—	*	*
Natural gas equivalent (per Mcfe)	6.92	6.77	8.62	2.2%	(21.5)%
Average Lifting Cost (per Mcfe) (4)	$1.11	$0.81	$1.08	37.0%	(25.0)%
Natural Gas Marketing (5)	$1,056	$1,977	$942	(46.6)%	109.9%
Other Costs and Expenses					
Exploration expense	$20,266	$18,177	$31,783	11.5%	(42.8)%
Impairment of proved natural gas and crude oil properties	—	926	7,579	(100.0)%	(87.8)%
General and administrative expense	42,188	53,985	37,715	(21.9)%	43.1%
Depreciation, depletion and amortization	109,243	126,755	101,443	(13.8)%	25.0%
Interest Expense	$33,250	$37,208	$28,132	(10.6)%	32.3%

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) Production is net and determined by multiplying the gross production volume of properties in which we have an interest by the percentage interest we own.
(2) Six Mcf of natural gas equals one Bbl of crude oil or NGL.
(3) Represents realized derivative gains and losses related to natural gas and crude oil sales segment, which do not include realized derivative gains and losses related to natural gas marketing.
(4) Represents lease operating expenses, exclusive of production taxes, on a per unit basis.
(5) Represents sales from natural gas marketing, net of costs of natural gas marketing, including realized and unrealized derivative gains and losses related to natural gas marketing activities.

Natural Gas, NGL and Crude Oil Sales

The following tables present natural gas, NGL and crude oil production and average sales price by area. Prior to 2010, NGLs were included in natural gas, which impacts the comparability for 2010 to 2009 and 2008.

	Year Ended December 31,			Change	
Production	2010	2009	2008	2010-2009	2009-2008
Natural gas (MMcf)					
Rocky Mountain Region	23,650.8	29,957.4	26,087.8	(21.1)%	14.8 %
Permian Basin	148.5	—	—	*	*
Appalachian Basin (1)	2,526.0	4,010.5	3,902.2	(37.0)%	2.8 %
Other	62.2	121.7	111.1	(48.9)%	9.5 %
Total	26,387.5	34,089.6	30,101.1	(22.6)%	13.3 %
Crude oil (MBbls)					
Rocky Mountain Region	1,224.9	1,233.3	1,127.9	(0.7)%	9.3 %
Permian Basin	34.0	—	—	*	*
Appalachian Basin (1)	5.9	9.6	6.6	(38.5)%	45.5 %
Other	0.5	1.1	1.3	(54.5)%	(15.4)%
Total	1,265.3	1,244.0	1,135.8	1.7 %	9.5 %
NGLs (MBbls)					
Rocky Mountain Region	561.1	—	—	*	*
Permian Basin	31.6	—	—	*	*
Other	8.5	—	—	*	*
Total	601.2	—	—	*	*
Natural gas equivalent (MMcfe)					
Rocky Mountain Region	34,367.2	37,357.0	32,855.1	(8.0)%	13.7 %
Permian Basin	541.7	—	—	*	*
Appalachian Basin (1)	2,561.4	4,068.1	3,941.9	(37.0)%	3.2 %
Other	116.3	128.3	118.6	(9.4)%	8.2 %
Total	37,586.6	41,553.4	36,915.6	(9.5)%	12.6 %

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

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(1) For 2010, the decrease in production was primarily the result of our contribution of natural gas and crude oil properties to PDCM. Effective January 1, 2010, PDCM was deconsolidated and accounted for in accordance with the proportionate consolidation method. See Note 1, Nature of Operations and Basis of Presentation, to our consolidated financial statements included in this report.

Average Sales Price (excluding gain/loss on derivatives)	Year Ended December 31, 2010	2009	2008	Change 2010-2009	2009-2008
Natural gas (per Mcf)					
Rocky Mountain Region	$3.52	$2.97	$6.53	18.5 %	(54.5)%
Permian Basin	3.54	—	—	*	*
Appalachian Basin	4.44	4.00	9.21	11.0 %	(56.6)%
Other	2.49	2.40	7.21	3.8 %	(66.7)%
Weighted average price	3.61	3.09	6.88	16.8 %	(55.1)%
Crude oil (per Bbl)					
Rocky Mountain Region	$73.95	$55.06	$89.63	34.3 %	(38.6)%
Permian Basin	76.56	—	—	*	*
Appalachian Basin	77.10	57.24	88.80	34.7 %	(35.5)%
Other	62.68	40.62	100.79	54.3 %	(59.7)%
Weighted average price	74.03	55.07	89.64	34.4 %	(38.6)%
NGLs (per Bbl)					
Rocky Mountain Region	$39.56	$—	$—	*	*
Permian Basin	47.20	—	—	*	*
Other	46.29	—	—	*	*
Weighted average price	40.05	—	—	*	*
Natural gas equivalent (per Mcfe)					
Rocky Mountain Region	$5.71	$4.20	$8.26	36.0 %	(49.2)%
Permian Basin	8.52	—	—	*	*
Appalachian Basin	4.55	4.08	9.27	11.5 %	(56.0)%
Other	4.99	2.62	7.81	90.5 %	(66.5)%
Weighted average price	5.67	4.19	8.37	35.3 %	(49.9)%

* Percentage change is not meaningful or equal to or greater than 300%.
Amounts may not recalculate due to rounding.

Natural gas, NGL and crude oil sales revenue in 2010 increased $38.9 million, excluding the provision for underpayment of natural gas sales, compared to 2009. Approximately $61.6 million of the increase was due to pricing, offset in part by decreased production, which reduced natural gas and oil sales by $22.7 million. The 2010 decrease in production was directly attributable to our decision to reduce our capital expenditures for new wells drilled in 2009 due to the decline in commodity prices from 2008 to 2009 and the continued significant uncertainty in the financial and commodity markets. The decrease in production was offset in part by our decision to report NGLs separately from natural gas volumes as these amounts are expected to become more significant as we concentrate our drilling and acquisition spending toward more liquid rich resources as well as to enhance comparability among our peers, which resulted in the recognition of approximately 1.9 Bcfe of additional production. As market conditions showed signs of improvement, we cautiously increased our capital spending. During the third quarter of 2010, we began to experience the first increase in our quarterly production rate since the third quarter of 2009. Our production in 2009 increased compared to 2008 primarily as a result of our 2008 investment in new wells drilled. Although production increased in 2009, natural gas, NGL and crude oil sales revenue decreased by $134.9 million, excluding the provision for underpayment of natural gas sales, compared to 2008, primarily due to depressed natural gas and crude oil pricing in 2009. The lower commodity prices contributed $172.1 million to the total decrease in natural gas, NGL and crude oil sales revenues, which was offset in part by the increase in production, contributing $37.2 million. The effects of the decrease in natural gas and crude oil pricing was significantly reduced by realized derivative gains in 2009 of $107.3 million. See Commodity Price Risk Management, Net discussion below. At December 31, 2010, our production exit rate was 109 MMcfe/day compared to 98 MMcfe/day at December 31, 2009, and 115 MMcfe/day at December 31, 2008.

Natural Gas and Crude Oil Pricing. Our results of operations depend upon many factors, particularly the price of natural gas and crude oil and our ability to market our production effectively. Natural gas and crude oil prices are among the most volatile of all commodity prices. These price variations have a material impact on our financial results. Natural gas prices vary by region and locality, depending upon the distance to markets, the availability of pipeline capacity 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 has resulted in local market oversupply situations from time to time. Like most producers in the region, we rely on major interstate pipeline companies to construct these pipelines to increase capacity, rendering the timing and availability of these facilities beyond our control. Crude oil pricing is predominately driven by the physical market, supply and demand, the financial markets and politics.

The price we receive for our natural gas produced in the Rocky Mountain Region is based on a market basket of prices, which generally includes natural gas sold at, near or below CIG prices as well as other nearby region 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. This negative differential has narrowed over the last few years and is lower than historical variances. The negative differential between NYMEX and CIG averaged $0.47, $0.92 and $2.80 for 2010, 2009 and 2008, respectively.

Production Costs. Production costs include our lease operating expenses, production taxes, the cost to operate wells and pipelines and certain production and engineering staff related overhead costs.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Lease operating expenses	$41,784	$33,807	$39,726
Production taxes	12,067	8,834	17,438
Costs of well operations and pipeline services	7,631	6,771	5,501
Overhead and other production expenses	5,335	12,691	12,534
Total production costs	$66,817	$62,103	$75,199

Lease operating expenses. Lifting costs per Mcfe were $1.11, $0.81 and $1.08 for 2010, 2009 and 2008, respectively. The increase per Mcfe in 2010 from 2009 was in part due to the 9.5% decrease in production volumes compared to volumes produced in 2009, resulting in the fixed portion of our production costs being allocated to a declining volume. A large component of the increase in our 2010 lease operating expenses were well workovers, which include an increase in tubing and casing repairs of $4.7 million and environmental remediation charges of $2.7 million. The decrease per Mcfe in 2009 from 2008 was primarily due to lower third party costs from service providers as a result of pressure by us to reduce costs as natural gas and crude oil prices deteriorated, our own cost reduction initiatives, and increased production, which allows us to spread the fixed portion of our production costs over the increased volume.

Production taxes. Production taxes fluctuate with natural gas, NGL and crude oil sales. The $3.2 million or 36.6% increase in production taxes for 2010 compared to 2009 was primarily related to the 22.4% increase in sales revenues and an increase in ad valorem tax rates for certain Colorado counties. The $8.6 million or 49.3% decrease in 2009 compared to 2008 was directly related to the 43.8% decrease in natural gas and crude oil sales along with a reduction of ad valorem tax rates for certain counties and an increase in the number of Colorado wells exempt from severance taxes due to their re-characterization as stripper wells.

Cost of well operations and pipeline services. The increases in costs of well operations and pipeline services for 2010 and 2009 compared to 2008 were the result of costs related to pipeline systems and compressor maintenance projects, with 2009 being offset in part by lower field services costs.

Overhead and other production expenses. Overhead and other production expenses decreased in 2010 compared to 2009 primarily due to the deconsolidation of PDCM with the remaining decrease resulting from reductions in various other expenses, including pipeline and compressor maintenance as well as a $2.7 million accrual recognized in 2009 for a firm transportation volume shortfall in our Piceance Basin. The slight decrease in 2009 from 2008 was primarily due to lower cost of field services, including vehicles, lower rates from third parties and less work and services being performed in this low commodity price environment, offset in part by a $2.7 million accrual for a firm transportation shortfall in the Piceance Basin.

Commodity Price Risk Management, Net

Commodity price risk management, net, includes realized gains and losses and unrealized changes in the fair value of derivative instruments related to our natural gas and crude oil production. Commodity price risk management, net, does not include derivative transactions related to our natural gas marketing, which are included in sales from and cost of natural gas marketing. See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report for additional details of our derivative financial instruments.

The following table presents the realized and unrealized derivative gains and losses included in commodity price risk management, net.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Commodity price risk management gain (loss), net:			
Realized gains (losses):			
Natural gas	$40,024	$89,464	$12,632
Crude oil	7,071	17,881	(3,145)
Total realized gains, net	47,095	107,345	9,487
Unrealized gains (losses):			
Reclassification of realized (gains) losses included in prior periods unrealized	(20,148)	(84,655)	549
Unrealized gains (losses) for the period	32,944	(32,743)	117,802
Total unrealized gains (losses), net	12,796	(117,398)	118,351
Total commodity price risk management gain (loss), net	$59,891	$(10,053)	$127,838

Realized gains recognized in 2010 are a result of lower natural gas and crude oil spot prices at settlement compared to the respective strike price, offset in part by a $12.1 million realized loss due to the negative basis differential between NYMEX and CIG being narrower than the strike price of our derivative position. During 2010, we recorded unrealized gains of $47.3 million on our natural gas positions offset in part by unrealized losses of $10.6 million on our crude oil positions and $3.8 million on our CIG basis swaps as the forward basis differential between NYMEX and CIG had continued to narrow.

During 2009, realized gains recognized were the result of lower natural gas and crude oil spot prices at settlement compared to the respective strike price. We recorded unrealized losses on our CIG basis swaps of $33.9 million as the forward basis differential between NYMEX and CIG had continued to narrow along with unrealized losses of $15 million on our crude oil positions, offset by unrealized gains of $16.2 million on our natural gas positions.

During the first half of 2008, we experienced both realized and unrealized derivative losses as natural gas and crude oil prices were at or near record prices. During the second half of the year, due to the tumbling commodity prices, we had both significant realized and unrealized derivative gains. The 2008 unrealized gain includes a gain on our natural gas and crude oil positions of $120.5 million and an unrealized loss on our CIG basis swaps of $2.7 million.

We use various derivative instruments to manage fluctuations in natural gas and crude oil prices. We have in place a variety of floors, collars, fixed-price swaps and basis swaps on a portion of our estimated natural gas and crude oil production. Because we sell all of our physical natural gas and crude oil at similar prices to the indexes inherent in our derivative instruments, we ultimately realize a price related to our collars of no less than the floor and no more than the ceiling and, for our commodity swaps, we ultimately realize the fixed price related to our swaps. See Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report and Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for a discussion of how each derivative type impacts our cash flows and a detailed presentation of our derivative positions as of December 31, 2010.

Natural Gas Marketing

Fluctuations in our natural gas marketing's income contribution are primarily due to fluctuations in commodity prices and realized and unrealized, mark-to-market adjustments, gains and losses on open derivative positions, and, to a lesser extent, volumes sold and purchased.

Derivative instruments related to natural gas marketing 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. See Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report and Item 7A, Quantitative and Qualitative Disclosures About Market Risk, for a discussion of how each derivative type impacts our cash flows and detailed presentation of our derivative positions as of December 31, 2010.

Other Costs and Expenses

Exploration Expense

The following table presents the major components of exploration expense.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Impairment of individually significant unproved properties	$1,477	$982	$9,165
Amortization of individually insignificant unproved properties	5,004	3,126	3,633
Exploratory dry hole costs	4,199	1,059	7,675
Geological and geophysical costs	2,367	1,788	2,121
Operating, personnel and other	7,219	11,222	9,189
Total exploration expense	$20,266	$18,177	$31,783

Impairment of individually significant unproved properties. In 2010, the impairment expense relates primarily to a leasehold abandoned in the Pennsylvania portion of the Appalachian Basin. In 2008, $7.3 million was related to unproved properties in the Fort Worth Basin.

Amortization of individually insignificant unproved properties. The increase in amortization of individually insignificant unproved properties in 2010 was primarily due to our lack of drilling in the NECO area and the Pennsylvania portion of the Appalachian Basin.

Exploratory dry hole costs. In 2010, exploratory dry hole costs includes the fracturing and testing of several exploratory zones on a well drilled in the Piceance Basin and a crude oil well drilled in the NECO area. In 2008, the exploratory dry hole costs relates primarily to a well in each of New York and Colorado.

Operating, personnel and other. Included in operating, personnel and other is $3.7 million for demobilization of our drilling operations in the Piceance Basin during 2009.

Impairment of Proved Natural Gas and Crude Oil Properties

In 2008, we recognized an impairment loss of $7.5 million on our proved natural gas and crude oil properties in the Fort Worth Basin.

General and Administrative Expense

General and administrative expense decreased $11.8 million in 2010 compared to 2009. The decrease was primarily related to charges recorded during the prior year period: $7.9 million related to the formation of PDCM, $2.9 million related to a separation agreement with a former executive vice president, $1.5 million related to the expensing of previously capitalized 2008 acquisition costs pursuant to the adoption of a new accounting standard and $1.3 million related to corporate relocation costs. The 2010 decrease was offset in part by an increase in payroll and payroll related expenses during 2010.

General and administrative expense for 2009 increased $16.3 million compared to 2008. The increase was primarily related to the formation, acquisition and relocation costs discussed above as well as an increase in staffing and payroll benefits, including stock-based compensation of $3.7 million.

Depreciation, Depletion and Amortization

Natural gas and crude oil properties. DD&A expense related to natural gas and crude oil properties is directly related to proved reserves and production volumes. DD&A expense is primarily based upon year-end proved developed producing reserves. For 2008 and prior, these reserves were valued based on the price of natural gas and crude oil as of December 31 for the respective year. Pursuant to the adoption of the SEC's new reserve estimation and reporting requirements, our 2009 reserve estimation changed from a December 31 single day pricing to a 12-month average of the first day of the month price for each month in the period. If prices increase, as they did from December 31, 2009, to December 31, 2010, the estimated volumes of proved reserves will increase, resulting in decreases in the rate of DD&A per unit of production. If prices decrease, as they did from December 31, 2008, to December 31, 2009, the estimated volumes of proved reserves will decrease, resulting in an increase in the rate of DD&A per unit of production.

The following table presents our DD&A rates for natural gas and crude oil properties by area.

	Year Ended December 31,		
	2010	2009	2008
	(per Mcfe)		
Rocky Mountain Region:			
Wattenberg Field (1)	$3.08	$3.81	$3.47
Grand Valley Field	2.49	2.35	2.04
Weighted average	2.72	2.92	2.62
Permian Basin	2.12	—	—
Appalachian Basin	2.57	2.06	1.55
Total weighted average	2.70	2.85	2.54

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(1) Although the Wattenberg Field development costs and DD&A rates are higher than the other fields, the relative value of its crude oil production currently more than offsets this cost difference. The Wattenberg Field has produced volumes in excess of 90% of our total crude oil production in each of the years in the three-year period ended December 31, 2010.

Non-natural gas and crude oil properties. Depreciation expense for non-natural gas and crude oil properties was $7.5 million for 2010 compared to $8.1 million for 2009 and $7.6 million for 2008.

Non-Operating Income/Expense

Interest Expense. The decrease in interest expense in 2010 compared to 2009 is primarily related to the lower average outstanding balances on our credit facility. The increase in interest expense in 2009 compared to 2008 was primarily due to significantly higher average outstanding balances on our credit facility offset in part by lower average interest rates in our bank credit facility. The average long-term debt in 2010 was $286.1 million compared to $392 million in 2009 and $275.9 million in 2008. Interest expense is net of capitalized interest. Interest costs capitalized in 2010, 2009 and 2008 were $0.3 million, $0.8 million and $2.6 million, respectively. We have historically utilized our daily cash balances to reduce our line of credit borrowings, thereby lowering our interest costs and interest income.

Provision/Benefit for Income Taxes

The effective tax rate ("rate") related to income from continuing operations for 2010 of 14.7% is lower than the statutory federal rate of 35% primarily due to the tax benefit associated with the deduction for percentage depletion as well as the $1.7 million discrete tax benefit due to our deferred rate change. The 2009 rate of 36% is a benefit on the loss from continuing operations which was increased by the benefit for current state losses and offset by nondeductible expenditures related to the formation of PDCM. The 2008 rate of 35.1% on income from continuing operations was impacted primarily by state income tax expense, offset by a benefit associated with the implementation of state tax planning strategies. Excluding the effect of discrete items, our 2010, 2009 and 2008 rate was 32.7%, 36.2% and 37.4%, respectively, with 2010 and 2008 representing provision on income and 2009 representing benefit on loss.

Beginning with our 2010 tax year, we were accepted into and have agreed to participate in the IRS Compliance Assurance Process ("CAP") program. As part of this program, we have agreed to an accelerated timeline for the IRS examination of our 2007, 2008 and 2009 tax years. This examination is expected to be completed during the second quarter of 2011. We have accepted an offer for continued participation in the IRS CAP program for our 2011 tax year.

Discontinued Operations

North Dakota. During the fourth quarter of 2010, we developed a plan to divest and began marketing for sale our North Dakota assets. In December 2010, we executed a letter of intent with an unrelated third party, which provides for the sale of 100% of our North Dakota assets. In February 2011, we executed a purchase and sale agreement with the same unrelated third party and expect the transaction to close in March 2011. The operating results related to these assets were immaterial to the financial statements with the following exception. In 2008, we recognized impairment losses on our proved natural gas and crude oil properties in North Dakota of $5.3 million, consisting of $3 million in our Bakken Field and $2.3 million in our Nesson Field. See Note 13, Assets Held for Sale, Divestiture and Discontinued Operations, to our consolidated financial statements included in this report for additional information regarding the divestiture of our North Dakota assets.

Michigan. In July 2010, we completed the sale of our Michigan assets. Operating results related to these assets were immaterial to the financial statements with the following exception. In June 2010, in conjunction with our decision to divest our Michigan assets, we recorded a related pre-tax impairment charge of $4.7 million. See Note 2, Summary of Significant Accounting Polices, Properties and Equipment - Proved Property Impairment, and Note 13, Assets Held for Sale, Divestiture and Discontinued Operations, to our consolidated financial statements included in this report for additional information regarding the divestiture of our Michigan assets.

Natural Gas and Crude Oil Well Drilling Operations. We offered our last partnership drilling program in 2007. Since then, we have not had significant revenue from this segment of our operations. As of June 2009, we had concluded all previous commitments related to partnership well drilling and completion activities and reported our natural gas and crude oil well drilling activities as discontinued operations.

Net Income (Loss) Attributable to Shareholders/Adjusted Net Income (Loss) Attributable to Shareholders

Net income attributable to shareholders for 2010 was $6.2 million compared to a net loss of $79.3 million for 2009 and net income of $113.3 million for 2008. Adjusted net income attributable to shareholders, a non-GAAP financial measure, for 2010 was $0.4 million compared to an adjusted net loss of $5.7 million for 2009 and an adjusted net income of $43.1 million for 2008. The year-over-year changes in net income (loss) attributable to shareholders are discussed above. These same reasons for change similarly impacted adjusted net income (loss) attributable to shareholders, with the exception of the unrealized derivative gains and losses on derivatives, adjusted for taxes. Adjusted net income (loss) attributable to shareholders excludes the impact of a tax adjusted unrealized derivative gain of $7.8 million for 2010, a tax adjusted unrealized loss of $71.9 million for 2009 and a tax adjusted unrealized gain of $72.7 million for 2008. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of this non-GAAP financial measure.

Financial Condition, Liquidity and Capital Resources

Historically, our primary sources of liquidity have been cash flows provided by operating activities and our bank credit facility. More recently, as market conditions have permitted, we have utilized the debt and equity markets and engaged in asset monetization transactions as sources of financing.

Our primary source of cash flows provided by operations is the sale of natural gas, NGL and crude oil. Fluctuations in our operating cash flow are substantially driven by commodity prices and changes in our production volumes. Commodity prices have historically been volatile and we manage this volatility through our derivative program, which has also historically been a source of cash from operations. We enter into commodity derivative instruments with maturities of no greater than five years from the date of the instrument. For instruments that mature in two years or less, our debt covenants limit our holdings to 80% of our expected future production on total proved reserves (PDPs, PDNPs and PUDs). For instruments that mature greater than two years but no more than our designated maximum maturity, our debt covenants limit our holdings to 80% of our expected future production on PDPs. Therefore, we may still have significant fluctuations in our cash flows provided by operating activities due to the remaining non-hedged portion.

Our working capital fluctuates for various reasons, including, but not limited to, changes in the fair value of our commodity derivative instruments and due to our practice of utilizing excess cash to reduce the outstanding borrowings under our credit facility. At December 31, 2010, we had a working capital surplus of $16.2 million compared to $32.9 million at December 31, 2009.

We began 2011 with cash and cash equivalents of $54.4 million and availability under our credit facility of $302.5 million, for a total liquidity position of $356.9 million compared to $238.2 million at the beginning of 2010. The increase in liquidity of $118.7 million, or 49.8%, was primarily due to the net proceeds of $236.7 million received in November 2010 through the sale of equity and the issuance of convertible senior notes, as well as cash flows provided by operating activities of $151.8 million and the increase in our credit facility borrowing base of $16.2 million from $305 million. These increases in available liquidity were offset in part by an increase in capital expenditures of $19.7 million, an $80 million pay down of our corporate credit facility and the acquisition of natural gas and crude oil properties totaling $158.1 million. With our current liquidity position and expected cash flow from operations, we believe that we have sufficient capital for operations and our planned uses of capital through 2011.

Capital Expenditures

We establish a capital plan each calendar year based on our development opportunities, liquidity position and the expected cash flows provided by operating activities for that year. We may revise our capital plan during the year as a result of acquisitions, drilling results, commodity prices, changes in our borrowing capacity and/or significant changes in cash flows. In January 2011, our Board of Directors approved our 2011 capital plan of $233 million, exclusive of the potential acquisition of the 2005 partnerships and any other future acquisition, which are expected to be provided through the utilization of our corporate credit facility. The plan provides for $205 million in developmental drilling, including recompletions and refractures, with the remaining $28 million for exploration, leasing and other capital needs. We believe, based on the current commodity price environment and our estimated 2011 production of 44.9 Bcfe, an increase of approximately 19% over 2010 production from continuing operations due to the increase in our 2010 drilling program compared to that of 2009, our cash flows provided by operating activities will fund the majority of our 2011 capital plan. Because natural gas and crude oil produced from our existing properties declines rapidly in the first two years of production, in order to grow our production, we need to continue to commit significant amounts of capital in 2011 and beyond. If capital is not available or is constrained in the future, we will be limited to our cash flows from operations and liquidity under our credit facility as the sources for funding our capital expenditures. We would not be able to maintain our current level of natural gas and crude oil production and cash flows provided by operating activities if capital markets and commodity prices were to become depressed and/or the borrowing base on our credit facility was reduced. The recurrence of such an event may result in our election to defer a substantial portion of our planned capital expenditures for 2011 and beyond and could have a material negative impact on our operations in the future.

Financing Activities

See Note 8, Long-Term Debt, and Note 12, Common Stock, to our consolidated financial statements in this report for detailed discussions of our November 2010 issuance of convertible senior notes and sale of equity, respectively. We have experienced no impediments in our ability to access borrowings under our current bank credit facility or the capital markets, as demonstrated by our November 2010 capital market transactions. We continue to monitor market events and circumstances and their potential impacts on each of the lenders that comprise our bank credit facility. Our $321.2 million bank credit facility borrowing base is subject to size redeterminations each May and November based upon a quantification of our proved reserves at each December 31st and June 30th, respectively. A commodity price deck reflective of the current and future commodity pricing environment is utilized by our lenders to quantify our reserve reports and determine the underlying borrowing base. Our next scheduled redetermination will be in May 2011. While we have continued to add producing reserves through our drilling operations since our last redetermination, we believe a significant decrease in commodity prices could have a negative impact on our future borrowing base redeterminations.

We have a shelf registration statement on Form S-3 with the SEC, filed in November 2008, and declared effective by the SEC in January 2009. The shelf provides for an aggregate of $500 million, through the potential sale of debt securities, common stock or preferred stock, either separately or represented by depository shares, warrants and purchase contracts, as well as units that may include any of these securities or securities of other entities. The shelf registration statement is intended to allow us to be proactive in our ability to raise capital should the need arise, and to have the flexibility to raise such funds in one or more offerings should we perceive the market conditions to be favorable. As of December 31, 2010, we have $315.8 million available on our shelf from which we may utilize to raise future capital.

We are subject to quarterly financial debt covenants on our bank credit facility. Currently, our key credit facility debt covenants require that we maintain: 1) total debt of less than 4.25 times earnings before interest, taxes, DD&A expense and capital expenditures ("EBITDAX") and 2) an adjusted working capital ratio of at least 1.0 to 1.0. Our adjusted working capital ratio is calculated by reducing our current assets and liabilities by any impact of recording the fair value of our natural gas and crude oil derivative instruments and adding our available borrowings on our bank credit facility to our current assets. The impact of any current portion of our debt is eliminated from the current liabilities, therefore any change in our available borrowings under our credit facility impacts our working capital ratio. We were in compliance with all debt covenants at December 31, 2010, and expect to remain in compliance throughout the next year.

The indenture governing our senior 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: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates and (g) merge or consolidate with another company. Additionally, with regard to our 12% senior notes, we are subject to two incurrence covenants: 1) EBITDAX of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants at December 31, 2010, and expect to remain in compliance throughout the next year.

See Part II, Item 7A, Quantitative and Qualitative Disclosures about Market Risk, for our discussion of credit risk.

Cash Flows

Operating Activities. Our net cash flow provided by operating activities is primarily impacted by commodity prices, production volumes, realized gains and losses from our derivative positions, operating costs and general and administrative expenses. Cash flows provided by operating activities increased in 2010 and 2009 compared to the respective prior year. In 2010, the increase was primarily due to the increase in natural gas, NGL and crude oil sales and the income tax refund of $25.9 million from our 2009 NOL carry-back received during the first half of 2010, offset by a decrease in realized derivative gains related to natural gas and crude oil sales of $60.2 million. In 2009, the increase was primarily due to the increase in realized gains from derivatives related to natural gas and crude oil sales of $97.9 million, the decrease in production costs of $13.1 million, offset by the decrease in natural gas, NGL and crude oil sales of $133.6 million and an increase in general and administrative costs of $16.3 million. The remaining changes in cash flows provided by operating activities were primarily due to changes in our assets and liabilities related to the timing of cash payments and receipts. The key components for the changes in our cash flows provided by operating activities are described in more detail in our Results of Operations above.

Adjusted cash flows from operations and adjusted EBITDA decreased in 2010 and 2009 compared to the respective prior year. These decreases were primarily due to the same factors mentioned above for changes in cash flows provided by operating activities without regard to timing of cash payments and receipts of our assets and liabilities. See Reconciliation of Non-GAAP Financial Measures, below, for a more detailed discussion of these non-GAAP financial measures.

Investing Activities. Cash flows used in investing activities primarily consist of the acquisition, exploration and development of natural gas and crude oil properties net of dispositions of natural gas and crude oil properties. In 2009, based on unstable economic conditions existing early in the year and uncertainty as to when commodity and financial markets would recover to a perceived normal level, we reduced our planned 2009 capital expenditures to approximately 33% of our 2008 level, focusing our investment in the liquids-rich section of our Wattenberg Field. In 2010, as the economic condition showed signs of recovery, we increased our capital spending by $177.7 million, including acquisitions, over that in 2009. Approximately 51% of our investment spending was directed toward organic development and the remaining 49% going toward the acquisition of natural gas and crude oil properties. The monetization of our Michigan asset group provided cash of $22 million. See Part I, Operations - Drilling Activities, for additional details on our drilling activities.

Financing Activities. Cash flows provided by financing activities in 2010 included gross proceeds of $132.5 million and $115 million from our November 2010 sale of equity and issuance of convertible debt, respectively. During 2010, our investing partner in PDCM contributed $35 million, of which our proportionate share was $20.1 million. This capital raise was offset in part by the net repayment of borrowings under our bank credit facility of $80 million. Cash flows used in financing activities in 2009 were primarily related to our efforts to manage our balance sheet during the unstable economic conditions existing in 2009 and the uncertainty as to when the commodity and financial markets would recover to a perceived normal level. As a result, our net borrowings of $159.6 million in 2008 shifted to a net repayment of borrowings of $114.5 million in 2009. In 2009, we raised $48.5 million in capital through an equity offering and monetized a portion of our Appalachian Basin assets, receiving $45 million as return of capital at the closing of the formation of PDCM. See Note 8, Long-Term Debt, Note 12, Common Stock, and Note 15, Noncontrolling Interest in Subsidiaries, to our consolidated financial statements included in this report for further discussion on our debt and equity offerings and the formation of our joint venture.

Contractual Obligations and Contingent Commitments

The table below presents our contractual obligations and contingent commitments as of December 31, 2010.

	Payments due by period				
Contractual Obligations and Contingent Commitments	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
	(in thousands)				
Long-term liabilities reflected on the consolidated balance sheets (1)					
Long-term debt (2)	$318,000	$—	$—	$—	$318,000
Derivative contracts (3)	53,465	16,820	36,645	—	—
Derivative contracts - affiliated partnerships (4)	18,956	6,845	12,111	—	—
Production tax liability	32,300	16,226	16,074	—	—
Other liabilities (5)	9,844	273	3,669	604	5,298
Asset retirement obligations	28,047	250	389	779	26,629
	460,612	40,414	68,888	1,383	349,927
Commitments, contingencies and other arrangements (6)					
Interest on long-term debt (7)	201,634	30,035	59,433	58,999	53,167
Operating leases	8,813	2,226	3,597	2,977	13
Rig commitment (8)	6,627	3,693	2,934	—	—
Drilling commitment	1,004	—	—	—	1,004
Firm transportation and processing agreements (9)	178,961	19,724	45,654	39,442	74,141
Other	500	—	250	250	—
	397,539	55,678	111,868	101,668	128,325
Total	$858,151	$96,092	$180,756	$103,051	$478,252

(1) Table does not include deferred income tax liability to taxing authorities of $188 million, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(2) Amount presented does not agree with the balance sheet in that it does not include $22.3 million in unamortized debt discount. See Note 8, Long-Term Debt, to our consolidated financial statements included in this report.

(3)

Represents our gross liability related to the fair value of derivative positions, including the fair value of derivative contracts we entered into on behalf of our affiliated partnerships as the managing general partner. We have a related receivable from the partnerships of $14.6 million.

(4) Represents our affiliated partnerships' designated portion of the fair value of our gross derivative assets.

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

(6) Table does not include the annual repurchase obligations to investing partners or termination benefits related to employment agreements with our executive officers, due to the uncertainty surrounding the ultimate settlement of amounts and timing of these obligations.

(7) Amounts presented include $20.1 million payable to the holders of our 3.25% convertible senior notes due 2016, $173.6 million to the holders of our 12% senior notes due 2018. Amounts also include $7.9 million payable to the participating banks of our revolving credit facility. As of December 31, 2010, there were no borrowings outstanding on our revolving bank credit facility; however, the $7.9 million represents amounts due on the unutilized commitment at a rate of 0.5% per annum plus a rate of 2.125% per annum related to our outstanding letter of credit.

(8) Drilling rig commitment in the above table reflects our proportionate share of the maximum obligation for the services of one drilling rig in the Appalachian Basin.

(9) Represents our gross commitment, including amounts for volumes transported or sold on behalf of our affiliated partnerships and other working interest owners. We will recognize in our financial statements our proportionate share based on our working interest. See Note 11, Commitments and Contingencies - Firm Transportation Agreements, to our consolidated financial statements included in this report.

As the managing general partner of 29 partnerships, we have liability for potential casualty losses in excess of the partnership assets and insurance. We believe that the casualty insurance coverage we and our subcontractors carry is adequate to meet this potential liability.

For information regarding our legal proceedings, see Note 11, Commitments and Contingencies – Litigation, to our consolidated financial statements included in this report. From time to time we are a party to various other legal proceedings in the ordinary course of business. We are not currently a party to any litigation that we believe would have a materially adverse effect on our business, financial condition, results of operations or liquidity.

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 U.S., with no need for our judgment in the application. There are also areas in which our judgment in selecting any available alternative would not produce a materially different result. However, certain of our accounting policies are particularly important to the portrayal of our financial position and results of operations and we may use significant judgment in the application; as a result, they are subject to an inherent degree of uncertainty. In applying those policies, we use our judgment to determine the appropriate assumptions to be used in the determination of certain estimates. Those estimates are based on historical experience, observation of trends in the industry, and information available from other outside sources, as appropriate. For a more detailed discussion on the application of these and other accounting policies, see Note 2, Summary of Significant Accounting Policies, to our consolidated financial statements included in this report. Our critical accounting policies and estimates are as follows:

Natural Gas and Crude Oil Properties. We account for our natural gas and crude oil 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 reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved reserves.

Annually, we engage independent petroleum engineers to prepare reserve and economic evaluations of all our properties on a well-by-well basis as of December 31. We adjust our natural gas and crude oil reserves for major acquisitions, new drilling and divestitures during the year as needed. The process of estimating and evaluating natural gas and crude oil reserves is complex, requiring significant decisions in the evaluation of available geological, geophysical, engineering and economic data. The data for a given property may also change substantially over time as a result of numerous factors, including additional development activity, evolving production history and a continual reassessment of the viability of production under changing economic conditions. As a result, revisions in existing reserve estimates occur. 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 over time. 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 prior to the issuance of the financial statements, the costs incurred, including costs for plugging, prior to the end of the reporting period are expensed to exploration expense. 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 applied.

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 natural gas and crude oil 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.

We assess our natural gas and crude oil 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 natural gas and crude oil. 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 natural gas and crude oil 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 vary significantly from actual results.

Consolidation and Accounting for Variable Interest Entities. Under applicable accounting guidance, a variable interest entity ("VIE") is consolidated by the entity's primary beneficiary. The primary beneficiary of a VIE has both the following characteristics: (1) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

In determining whether we are the primary beneficiary of the VIE, we consider a number of factors, including our ability to direct the activities that most significantly affect the entity's economic success and our contractual rights and responsibilities under the arrangement. These considerations impact the way we account for our existing joint venture relationship. Further, as certain events occur, we reconsider whether those events have caused us to become the primary beneficiary. The consolidation status of our VIE may change if the composition of the board of managers changes or we enter into new or modified contractual arrangements. A reconsideration event may also occur when we acquire new or additional interests in a VIE.

Natural Gas, NGL and Crude Oil Sales Revenue Recognition. Natural gas, NGL and crude oil sales are recognized when production is sold to a purchaser at a determinable price, delivery has occurred, rights and responsibility of ownership have transferred and collection of revenue is reasonably assured. We record sales revenue based on an estimate of the volumes delivered at prices tied to market indexes, adjusted based on agreed upon contract terms. We estimate our sales volumes based on company measured volume readings. We then adjust our natural gas, NGL and crude oil sales in subsequent periods based on the data received from our purchasers that reflects actual volumes received. We receive payment for sales from one to three months after actual delivery has occurred. The differences in sales estimates and actual sales are recorded up to two months later. Historically, differences have been immaterial.

Fair Value of Financial Instruments. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us 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 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, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. 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. Included in Level 1 are our commodity derivative instruments 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. Included in Level 3 are our commodity derivative instruments for CIG and PEPL-based natural gas swaps, oil swaps, natural gas and oil collars, and physical sales and purchases and our natural gas basis protection derivative instruments.

Derivative Financial Instruments. We measure fair value of our derivatives 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. We primarily use three investment grade financial institutions as our counterparties to our derivative contracts. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. 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.

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, we establish a valuation allowance. The factors which we consider in assessing whether we will realize the value of deferred income tax assets involve judgments and estimates of both amount and timing, which could differ from actual results, achieved in future periods.

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

Accounting for Acquisitions Using Purchase Accounting. We utilize the purchase method to account for acquisitions. Pursuant to purchase method accounting, we 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. When appropriate, we review comparable purchases and sales of natural gas and crude oil 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.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relate to the estimated fair values assigned to proved developed producing, proved developed non-producing, proved undeveloped, unproved natural gas and crude oil properties and other non-natural gas and crude oil properties. To estimate the fair values of these properties, we prepare estimates of natural gas and crude oil reserves. We estimate future prices by using the applicable forward pricing strip to apply to our estimate of reserve quantities acquired, and estimates of future operating and development costs, to arrive at an estimate of future net revenues. For estimated proved reserves, the future net revenues are 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 is subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved properties, we reduce the discounted future net revenues of probable and possible reserves by additional risk-weighting factors.

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

Recent Accounting Standards

See Note 2, Summary of Significant Accounting Policies - Recent Accounting Standards, to our consolidated financial statements included in this report.

Reconciliation of Non-GAAP Financial Measures

Adjusted cash flow from operations. We define adjusted cash flow from operations as the cash flow earned or incurred from operating activities without regard to the collection or payment of associated receivables or payables. We believe it is important to consider adjusted cash flow from operations as well as cash flow from operations, as we believe it often provides more transparency into what drives the changes in our operating trends, such as production, prices, operating costs, and related operational factors, without regard to whether the earned or incurred item was collected or paid during the period. We also use this measure because the collection of our receivables or payment of our obligations has not been a significant issue for our business, but merely a timing issue from one period to the next, with fluctuations generally caused by significant changes in commodity prices. See the Consolidated Statements of Cash Flows in this report.

Adjusted net income (loss) attributable to shareholders. We define adjusted net income (loss) attributable to shareholders as net income (loss) attributable to shareholders plus unrealized derivative losses, provisions for underpayment of natural gas sales, minus unrealized derivative gains, each adjusted for tax effect. We believe it is important to consider adjusted net income (loss) attributable to shareholders as well as net income (loss) attributable to shareholders. We believe it often provides more transparency into our operating trends, such as production, prices, operating costs, realized gains and losses from derivatives and related factors, without regard to changes in our net income (loss) attributable to shareholders from our mark-to-market adjustments resulting from unrealized gains and losses from derivatives. Additionally, other items, such as the provision for underpayment of natural gas sales, which are not indicative of future results, may be excluded to clearly identify operational trends.

Adjusted EBITDA. We define adjusted EBITDA as net income (loss) plus unrealized derivative loss, interest expense, net of interest income, income taxes, and depreciation, depletion and amortization for the period minus unrealized derivative gain. We believe adjusted EBITDA is relevant because it is a measure of cash available to fund our capital expenditures and service our debt and is a widely used industry metric which allows comparability of our results with our peers.

The following table presents a reconciliation of each of our non-GAAP financial measures to its nearest GAAP measure.

	Year Ended December 31, 2010	2009	2008
	(in thousands)		
Adjusted cash flow from operations:			
Adjusted cash flow from operations	$132,257	$170,214	$199,919
Changes in assets and liabilities	19,556	(26,319)	(60,818)
Net cash provided by operating activities	$151,813	$143,895	$139,101
Adjusted net income (loss) attributable to shareholders:			
Adjusted net income (loss) attributable to shareholders	$402	$(5,735)	$43,102
Unrealized gain (loss) on derivatives, net	12,625	(116,623)	117,536
Provision for underpayment of natural gas sales	(3,252)	(2,706)	(4,025)
Tax effect of above adjustments	(3,561)	45,787	(43,304)
Net income (loss) attributable to shareholders	$6,214	$(79,277)	$113,309
Adjusted EBITDA:			
Adjusted EBITDA	$138,268	$159,668	$189,413
Unrealized gain (loss) on derivatives, net	12,625	(116,623)	117,536
Interest expense, net	(33,179)	(36,954)	(27,541)
Income tax benefit (expense)	(438)	45,636	(61,459)
Depreciation, depletion and amortization	(111,062)	(131,004)	(104,640)
Net income (loss) attributable to shareholders	$6,214	$(79,277)	$113,309

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURE ABOUT MARKET RISK

Market-Sensitive Instruments and Risk Management

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

Interest Rate Risk

Changes in interest rates affect the amount of interest we earn on our cash, cash equivalents and restricted cash and the interest we pay on borrowings under our bank credit facility. All of our other long-term indebtedness have a fixed rate and, therefore, near-term changes in interest rates do not expose us to risk of earnings or cash flow loss; however, near-term changes in interest rates may affect the fair value of our fixed-rate debt.

As of December 31, 2010, our interest-bearing deposit accounts included money market accounts, certificates of deposit and checking and savings accounts with various banks. The amount of our interest-bearing cash and cash equivalents as of December 31, 2010, was $76.8 million with an average interest rate of 0.5%. The $76.8 million represents our aggregate bank balances, which includes checks issued and outstanding. Based on a sensitivity analysis of our interest bearing deposits as of December 31, 2010, it was estimated that if market interest rates were to increase or decrease by 1% in 2011, the impact on our annual interest income would be $0.8 million.

As of December 31, 2010, with the exception of our $18.7 million irrevocable standby letter of credit, we had no outstanding borrowings on our bank credit facility. Assuming our weighted average borrowing rate in 2010 averaged 1% higher (lower) in 2010, we estimate that our annual interest expense, would have increased (decreased) by approximately $0.7 million.

Commodity Price Risk

We are exposed to commodity price risk, the potential risk of loss from adverse changes in the market price of natural gas and crude oil commodities. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using derivative instruments. These instruments allow us to predict with greater certainty the effective natural gas and crude oil prices to be received for our hedged production as it is produced. We believe that our established derivative policies and procedures are effective in achieving our risk management objectives.

The following table presents our derivative positions (excluding the derivative positions designated to our affiliated partnerships) related to natural gas and crude oil sales in effect as of December 31, 2010.

	Floors		Collars			Fixed-Price Swaps		CIG Basis Protection Swaps		
Commodity/ Index/ Maturity Period	Quantity (Oil - MBbls)	Weighted Average Contract Price	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price Floors	Weighted Average Contract Price Ceilings	Quantity (Gas - BBtu (1) Oil - MBbls)	Weighted Average Contract Price	Quantity (BBtu) (1)	Weighted Average Contract Price	Fair Value December 31, 2010 (2) (in thousands)
Natural Gas										
NYMEX										
2011	—	$ —	866.2	$ 6.03	$ 9.37	10,579.9	$ 6.90	8,916.5	$ (1.81)	$ 13,988
2012	—	—	4,831.4	6.00	8.27	5,545.7	7.04	9,042.5	(1.80)	4,501
2013	—	—	4,438.0	6.10	8.60	4,659.7	7.09	8,156.4	(1.80)	2,790
CIG										
2011	—	—	1,128.5	4.75	9.45	959.7	5.81	—	—	2,495
2012	—	—	—	—	—	—	—	—	—	—
2013	—	—	—	—	—	—	—	—	—	—
PEPL										
2011	—	—	390.0	5.76	9.56	2,117.4	6.18	—	—	4,599
2012	—	—	—	—	—	1,355.8	6.18	—	—	1,886
2013	—	—	—	—	—	990.4	6.18	—	—	1,190
Total Natural Gas	—		11,654.1			26,208.6		26,115.4		31,449
Crude Oil										
NYMEX										
2011	155.0	74.03	231.5	73.00	99.80	545.2	75.88	—	—	(10,606)
2012	36.0	65.38	368.6	75.00	101.20	231.0	83.11	—	—	(3,870)
2013	—	—	317.6	75.00	104.30	186.9	84.15	—	—	(2,363)
Total Crude Oil	191.0		917.7			963.1		—		(16,839)
Total Natural Gas and Crude Oil										$ 14,610

(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

(2) Approximately 34% of the fair value of our derivative assets and 100% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

The following table presents our derivative positions related to our natural gas marketing in effect as of December 31, 2010.

	Collars			Fixed-Price Swaps		NYMEX Basis Protection Swaps		
Commodity/ Derivative Instrument/ Maturity Period	Quantity (BBtu)(1)	Weighted Average Contract Price Floors	Ceilings	Quantity (BBtu)(1)	Weighted Average Contract Price	Quantity (BBtu)(1)	Weighted Average Contract Price	Fair Value December 31, 2010 (2) (in thousands)
Natural Gas Sales								
Physical								
2011	—	$—	$—	49.4	$5.02	159.0	$0.63	$73
2012	—	—	—	—	—	53.3	1.04	37
2013 - 2014								
Financial								
2011	52.5	4.53	7.16	1,048.2	6.14	—	—	1,754
2012				62.5	4.56			(30)
2013 - 2014								
Purchases								
Physical								
2011	52.5	4.53	7.14	1,049.7	6.11	—	—	(1,450)
2012	—	—	—	62.5	4.50	—	—	46
2013 - 2014								
Financial								
2011	—	—	—	47.9	4.38	102.6	0.19	9
2012	—	—	—	—	—	30.4	0.13	—
2013 - 2014								
Total Natural Gas	105.0			2,320.2		345.3		$439

(1) A standard unit of measurement for natural gas (one BBtu equals one MMcf).

(2) Approximately 12% of the fair value of our derivative assets and 98% of our derivative liabilities were measured using significant unobservable inputs (Level 3); see Note 3, Fair Value Measurements, to the accompanying financial statements.

The following table presents monthly average NYMEX and CIG closing prices for natural gas and crude oil for the years ended December 31, 2010 and 2009, as well as average sales prices we realized for the respective commodities.

	Year Ended December 31,	
	2010	2009
Average Index Closing Price		
Natural Gas (per MMBtu)		
CIG	$3.92	$3.07

NYMEX	4.39	3.99
Crude Oil (per Bbl)		
NYMEX	77.32	58.36
Average Sales Price Realized (1)		
Excluding realized derivative gains/(losses)		
Natural Gas (per Mcf)	$3.61	$3.09
Crude Oil (per Bbl)	74.03	55.07
Including realized derivative gains/(losses)		
Natural Gas (per Mcf)	5.12	5.72
Crude Oil (per Bbl)	79.62	69.44

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(1) Prior to 2010, NGLs were included in natural gas, which impacts the comparability for 2010 to 2009.

Based on a sensitivity analysis as of December 31, 2010, it was estimated that a 10% increase in natural gas and crude oil prices, inclusive of basis, over the entire period for which we have derivatives then in place, including those designated to our affiliated partnerships, would result in a decrease in fair value of $34.7 million; whereas a 10% decrease in prices would result in an increase in fair value of $34.8 million. Excluding the derivatives designated to our affiliated partnerships, the same 10% increase or decrease in natural gas and crude oil prices would result in a decrease in fair value of $29.5 million and an increase in fair value of $29.6 million, respectively.

See Note 3, Fair Value of Financial Instruments, and Note 4, Derivative Financial Instruments, to our consolidated financial statements included in this report for a summary of our open derivative positions as well as a discussion of how we determine the fair value and account for our derivative contracts.

Credit Risk

Credit risk represents the loss that we would incur if a counterparty fails to perform under its contractual obligations. We attempt to reduce credit risk by diversifying our counterparty exposure and entering into transactions with high-quality counterparties. When 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.

With regard to our natural gas and crude oil sales segment, inherent to our industry is the concentration of natural gas, NGL and crude oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. As for our natural gas marketing segment, our receivables are from a diverse group of companies, including major energy companies, both upstream and mid-stream, financial institutions and end-users in various industries. We monitor their creditworthiness through credit reports and rating agency reports. To date, we have had no material counterparty default losses in either of our natural gas and crude oil sales segment or natural gas marketing segment. See Note 5, Concentration of Risk, to our consolidated financial statements included in this report.

Our derivative financial instruments expose us to the credit risk of nonperformance by the counterparty to the contracts. We primarily use financial institutions, which are also major lenders in our credit facility, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default rates, giving consideration to amounts outstanding from each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant.

Disruption in the credit market may have a significant adverse impact on a number of financial institutions. We monitor the creditworthiness of the financial institutions with which we transact, giving consideration to the reports of credit agencies and their related ratings. While we believe that our monitoring procedures are sufficient and customary, no amount of analysis can guarantee performance by a financial institution.

Disclosure of Limitations

Because the information above included only those exposures that exist at December 31, 2010, 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 commodity price risk management strategies at the time, and interest rates and commodity prices at the time.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As of December 31, 2010, we carried out an evaluation under the supervision and with the participation of management, including the Chief Executive Officer and the Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rules 13a-15(e) and 15d-15(e). Based on the results of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective as of December 31, 2010.

Changes in Internal Control over Financial Reporting

During the fourth quarter of 2010, we made no changes in our internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act) that have materially affected or are reasonably likely to materially affect our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

ITEM 11. EXECUTIVE COMPENSATION

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

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

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

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

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

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

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

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(a) (1) Financial Statements:
See Index to Financial Statements and Schedules on page F-1.
(2) Financial Statement Schedules:
See Index to Financial Statements and Schedules on page F-1.
Schedules and Financial Statements Omitted

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

(3) Exhibits:

See Exhibits Index on the following page.

Exhibits Index

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
3.1	Second Amended and Restated Certificate of Incorporation of Petroleum Development Corporation.	8-K	000-07246	3.1	7/23/2008	
3.2	Bylaws of Petroleum Development Corporation, amended and restated, effective October 11, 2007.	8-K	000-07246	3.2	10/17/2007	
4.1	Rights Agreement by and between Petroleum Development Corporation and Transfer Online, Inc., as Rights Agent, dated as of September 11, 2007, including the forms of Rights Certificates and Summary of Stockholder Rights Plan attached thereto as Exhibits A and B.	8-K	000-07246	4.1	9/14/2007	
4.2	Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and The Bank of New York.	8-K	000-07246	4.1	2/12/2008	
4.3	First Supplemental Indenture dated as of February 8, 2008, by and among Petroleum Development Corporation and the Bank of New York.	8-K	000-07246	4.2	2/12/2008	
4.4	Form of 12% Senior Note due 2018.	8-K	000-07246	4.3	2/12/2008	
10.1	Purchase Agreement dated as of February 1, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	2/7/2008	
10.2	Registration Rights Agreement dated as of February 8, 2008, by and among Petroleum Development Corporation and the Initial Purchasers of 12% senior notes due 2018 named therein.	8-K	000-07246	10.1	2/12/2008	
10.3	Underwriting Agreement dated August 11, 2009 among the Company and J.P. Morgan Securities Inc., as representative of the several Underwriters named therein.	8-K	000-07246	1.1	8/11/2009	
10.4*	2006 Long-Term Equity Compensation Grants to Executive Officers.	8-K	000-07246	10.20	4/10/2007	

10.5*	Indemnification Agreement with Directors.	10-Q	000-07246	10.1	8/9/2007	
10.6*	The Petroleum Development Corporation 401(k) & Profit Sharing Plan.					X
10.7*	2005 Non-Employee Director Restricted Stock Plan, amended and restated as of March 8, 2008.	S-8	333-126444	10.1	2/26/2009	
10.8	Contribution Agreement by and among PDC Mountaineer, LLC, as the Company, Petroleum Development Corporation, as the Contributor, and LR-Mountaineer Holdings, L.P., as the Investor, dated October 29, 2009.	8-K	000-07246	2.1	11/4/2009	
10.9	Limited Liability Company Agreement of PDC Mountaineer, LLC, dated October 29, 2009.	8-K	000-07246	10.1	11/4/2009	
10.10*	Non-Employee Director Deferred Compensation Plan.	S-8	333-118222	99.1	8/13/2004	
10.11*	2004 Long-Term Equity Compensation Plan amended and restated as of March 8, 2008.	10-K	000-07246	10.26	2/27/2009	
10.12*	2010 Short-Term Incentive Compensation Performance Metrics for Executive Officers.	8-K	000-07246		3/18/2010	
10.13*	Non-Employee Director Compensation for the 2010-2011 Term.	8-K	000-07246		4/23/2010	
10.14*	Executive Compensation and Short-Term Incentive Targets for 2010.	8-K	000-07246		4/23/2010	
10.15*	Employment Agreement with Richard W. McCullough, Chief Executive Officer, dated as of April 19, 2010.	8-K	000-07246	10.1	4/23/2010	
10.16*	Employment Agreement with Gysle R. Shellum, Chief Financial Officer, dated as of April 19, 2010.	8-K	000-07246	10.2	4/23/2010	
10.17*	Employment Agreement with Daniel W. Amidon, General Counsel and Corporate Secretary, dated as of April 19, 2010	8-K	000-07246	10.3	4/23/2010	

ExhibitNumber	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith
10.18*	Employment Agreement with Lance A. Lauck, Senior Vice President of Business Development, dated as of April 19, 2010.	8-K	000-07246	10.4	4/23/2010	
10.19*	Employment Agreement with Barton R. Brookman, Jr., Senior Vice President of Exploration and Production, dated as of April 19, 2010.	8-K	000-07246	10.5	4/23/2010	
10.20*	2010 Long-Term Equity Compensation Plan.	S-8	333-167945	99.1	7/1/2010	
10.21 †	Domestic Crude Oil Purchase Agreement between Suncor Energy Marketing, Inc. and PDC, dated May 18, 2009.	10-Q	000-53201	10.1	5/18/2009	
10.22 †	Gas Purchase Agreement between Williams Production RMT Company, Riley Natural Gas and Petroleum Development Corporation, dated as of March 31, 2009.	10/A No. 3	000-53201	10.7	3/31/2009	
10.23 †	Gas Purchase and Processing Agreement between Duke Energy Field Services, Inc.; United States Exploration, Inc.; and Petroleum Development Corporation, dated as of October 28, 1999.	10/A No. 3	000-53201	10.3	3/31/2009	
10.24	Second Amended and Restated Credit Agreement dated as of November 5, 2010, Petroleum Development Corporation, as borrower and JPMorgan Chase Bank, N.A. and BNP Paribas, as lenders.	8-K	000-07246	10.1	11/12/2010	
10.25	Underwriting Agreement dated November 18, 2010, among Petroleum Development Corporation and Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of the several underwriters.	8-K	000-07246	1.1	11/24/2010	
10.26	Purchase Agreement, dated as of November 18, 2010, among Petroleum Development Corporation and Wells Fargo Securities, LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representatives of	8-K	000-07246	1.1	11/24/2010	

	the initial purchasers.					
10.27	Indenture, dated November 23, 2010, between the Company and The Bank of New York Mellon.	8-K	000-07246	4.1	11/24/2010	
10.28	Form of 3.25% Convertible Senior Note due 2016	8-K	000-07246	4.1	11/24/2010	
10.29	First Amendment to Second Amended and Restated Credit Agreement.					X
12.1	Computation of Ratio of Earnings to Fixed Charges.					X
14.1	Code of Business Conduct and Ethics.	10-Q	000-17246	14.1	8/10/2009	
21.1	Subsidiaries.					X
23.1	Consent of PricewaterhouseCoopers LLP.					X
23.2	Consent of Ryder Scott Company, L.P., Petroleum Consultants.					X
31.1	Certification by Chief Executive Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
31.2	Certification by Chief Financial Officer pursuant to Rule 13a-14(a) and 15d-14(a) of the Exchange Act Rules, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.					X
32.1	Certifications by Chief Executive Officer and Chief Financial Officer pursuant to Title 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of Sarbanes-Oxley Act of 2002.					X
99.1	Report of Independent Petroleum Consultants - Ryder Scott Company, L.P.					X

*Management contract or compensatory plan or arrangement.
† Confidential portions of this document have been omitted and will be filed separately with the SEC pursuant to Exchange Act Rule 24b-2 on or before March 4, 2011.

SIGNATURES

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

PETROLEUM DEVELOPMENT CORPORATION

By /s/ Richard W. McCullough
Richard W. McCullough,
Chairman and Chief Executive Officer

February 24, 2011

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

Signature	Title	Date
/s/ Richard W. McCullough Richard W. McCullough	Chairman and Chief Executive Officer (principal executive officer)	February 24, 2011
/s/ Gysle R. Shellum Gysle R. Shellum	Chief Financial Officer (principal financial officer)	February 24, 2011
/s/ R. Scott Meyers R. Scott Meyers	Chief Accounting Officer (principal accounting officer)	February 24, 2011
/s/ Daniel W. Amidon Daniel W. Amidon	General Counsel and Corporate Secretary	February 24, 2011
/s/ Joseph E. Casabona Joseph E. Casabona	Director	February 24, 2011
/s/ Anthony J. Crisafio Anthony J. Crisafio	Director	February 24, 2011
/s/ Larry F. Mazza Larry F. Mazza	Director	February 24, 2011
/s/ David C. Parke David C. Parke	Director	February 24, 2011
/s/ Jeffrey C. Swoveland Jeffrey C. Swoveland	Director	February 24, 2011
/s/ James M. Trimble James M. Trimble	Director	February 24, 2011
/s/ Kimberly Luff Wakim	Director	February 24, 2011

Kimberly Luff Wakim

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Index to Consolidated Financial Statements and Financial Statement Schedule

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 Rules 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, 2010, 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 maintained effective internal control over financial reporting as of December 31, 2010.

The effectiveness of Petroleum Development Corporation's internal control over financial reporting as of December 31, 2010, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

PETROLEUM DEVELOPMENT CORPORATION

/s/ Richard W. McCullough
Richard W. McCullough
Chairman and Chief Executive Officer

/s/ Gysle R. Shellum
Gysle R. Shellum
Chief Financial Officer

/s/ R. Scott Meyers
R. Scott Meyers
Chief Accounting Officer

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of Petroleum Development Corporation:

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, equity, and cash flows present fairly, in all material respects, the financial position of Petroleum Development Corporation and its subsidiaries at December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule appearing under Item 15(a)(2) 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 maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). 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 the accompanying Management's Report on Internal Control Over Financial Reporting. 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 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 audits 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 audits 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 audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company changed the manner in which it accounts for the consolidation of variable interest entities in 2010.

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

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

/s/ PricewaterhouseCoopers LLP

Pittsburgh, Pennsylvania
February 24, 2011

Petroleum Development Corporation
(dba PDC Energy)
Consolidated Balance Sheets
(in thousands, except share and per share data)

As of December 31,	2010	2009
Assets		
Current assets:		
Cash and cash equivalents	$54,372	$31,944
Accounts receivable, net	53,978	56,491
Accounts receivable affiliates	11,448	7,956
Fair value of derivatives	42,953	42,223
Income tax receivable	1,339	27,728
Prepaid expenses and other current assets	12,733	11,028
Total current assets	176,823	177,370
Properties and equipment, net	1,120,038	973,658
Assets held for sale	5,191	34,535
Fair value of derivatives	44,464	20,228
Accounts receivable affiliates	8,478	15,473
Other assets	34,041	29,063
Total Assets	$1,389,035	$1,250,327
Liabilities and Equity		
Liabilities		
Current liabilities:		
Accounts payable	$47,271	$36,845
Accounts payable affiliates	9,605	13,015
Production tax liability	16,226	24,849
Fair value of derivatives	29,998	20,208
Funds held for distribution	29,755	28,256
Accrued interest payable	10,051	9,782
Other accrued expenses	17,723	11,479
Total current liabilities	160,629	144,434
Long-term debt	295,695	280,657
Deferred income taxes	187,999	178,012
Asset retirement obligation	27,797	29,314
Fair value of derivatives	36,644	48,779
Accounts payable affiliates	12,111	5,996
Other liabilities	25,919	24,542
Total liabilities	746,794	711,734
Commitments and contingent liabilities		
Equity		
Shareholders' equity:		
Preferred shares, par value $0.01 per share; authorized 50,000,000 shares; issued: none	—	—

Common shares, par value $0.01 per share; authorized 100,000,000 shares;		
issued: 23,462,326 in 2010 and 19,242,219 in 2009	235	192
Additional paid-in capital	209,198	64,406
Retained earnings	432,843	426,629
Treasury shares, at cost: 2,938 in 2010 and 8,273 in 2009	(111)	(312)
Total shareholders' equity	642,165	490,915
Noncontrolling interest in subsidiaries	76	47,678
Total equity	642,241	538,593
Total Liabilities and Equity	$1,389,035	$1,250,327

See accompanying Notes to Consolidated Financial Statements

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Petroleum Development Corporation
(dba PDC Energy)
Consolidated Statements of Operations
(in thousands, except per share data)

Year Ended December 31,	2010	2009	2008
Revenues:			
Natural gas, NGL and crude oil sales	$209,644	$171,242	$304,867
Sales from natural gas marketing	69,071	59,595	129,015
Commodity price risk management gain (loss), net	59,891	(10,053)	127,838
Well operations, pipeline income and other	9,041	10,092	10,781
Total revenues	347,647	230,876	572,501
Costs, expenses and other:			
Production costs	66,817	62,103	75,199
Cost of natural gas marketing	68,015	57,618	128,073
Exploration expense	20,266	18,177	31,783
Impairment of proved natural gas and crude oil properties	—	926	7,579
General and administrative expense	42,188	53,985	37,715
Depreciation, depletion, and amortization	109,243	126,755	101,443
Gain on sale of leaseholds	(174)	(470)	—
Total cost, expenses and other	306,355	319,094	381,792
Income (loss) from operations	41,292	(88,218)	190,709
Interest income	71	254	591
Interest expense	(33,250)	(37,208)	(28,132)
Income (loss) from continuing operations before income taxes	8,113	(125,172)	163,168
Provision (benefit) for income taxes	1,192	(45,054)	57,337
Income (loss) from continuing operations	6,921	(80,118)	105,831
Income (loss) from discontinued operations, net of tax	(987)	(975)	7,413
Net income (loss)	5,934	(81,093)	113,244
Less: net loss attributable to noncontrolling interests	(280)	(1,816)	(65)
Net income (loss) attributable to shareholders	$6,214	$(79,277)	$113,309
Amounts attributable to Petroleum Development Corporation shareholders:			
Income (loss) from continuing operations	$7,201	$(78,302)	$105,896
Income (loss) from discontinued operations, net of tax	(987)	(975)	7,413
Net income (loss) attributable to shareholders	$6,214	$(79,277)	$113,309
Earnings (loss) per share attributable to shareholders:			
Basic			
Income (loss) from continuing operations	$0.37	$(4.76)	$7.19
Income (loss) from discontinued operations	(0.05)	(0.06)	0.50
Net income (loss) attributable to shareholders	$0.32	$(4.82)	$7.69
Diluted			

Income (loss) from continuing operations	$0.36	$(4.76)	$7.13
Income (loss) from discontinued operations	(0.05)	(0.06)	0.50
Net income (loss) attributable to shareholders	$0.31	$(4.82)	$7.63
Weighted average common shares outstanding			
Basic	19,674	16,448	14,736
Diluted	19,821	16,448	14,848

See accompanying Notes to Consolidated Financial Statements

Petroleum Development Corporation
(dba PDC Energy)
Consolidated Statements of Cash Flows
(in thousands)

Year Ended December 31,	2010	2009	2008
Cash flows from operating activities:			
Net income (loss)	$5,934	$(81,093)	$113,244
Adjustments to net income (loss) to reconcile to net cash provided by operating activities:			
Unrealized (gain) loss on derivatives, net	(12,625)	116,623	(117,536)
Depreciation, depletion and amortization	111,062	131,004	104,640
Impairment of proved natural gas and oil properties	4,666	926	22,091
Expired and abandoned leases	6,481	7,279	3,633
Exploratory dry hole costs	4,199	1,059	6,504
Accretion of asset retirement obligation	1,423	1,368	1,230
Stock-based compensation	5,314	5,935	6,702
Excess tax benefits from stock-based compensation	(293)	—	(1,031)
Loss (gain) from sale of leaseholds/assets	299	(105)	19
Amortization of debt issuance costs	4,618	5,302	1,344
Deferred income taxes	1,179	(18,084)	59,079
Total adjustments to net income (loss) to reconcile to net cash provided by operating activities:	126,323	251,307	86,675
Changes in current assets and liabilities:			
Decrease (increase) in restricted cash	219	15,564	(4,257)
Decrease (increase) in accounts receivable	2,122	13,197	(9,664)
Decrease (increase) in accounts receivable - affiliates	(450)	14,282	(7,631)
Decrease (increase) in income taxes receivable	26,389	(27,728)	—
Decrease (increase) in other current assets	(2,348)	16,478	(7,855)
Increase (decrease) in production tax liability	(6,818)	(4,541)	9,857
Increase (decrease) in accounts payable and accrued expenses	1,172	(22,482)	2,790
Increase (decrease) in accounts payable - affiliates	(3,812)	(7,566)	10,282
Increase (decrease) in advances for future drilling contracts	—	(1,675)	(66,742)
Increase (decrease) in federal and state income taxes payable	402	(2,580)	1,721
Increase (decrease) in funds held for future distribution	2,018	(22,105)	10,538
Other	662	2,837	143
Total changes in current assets and liabilities	19,556	(26,319)	(60,818)
Net cash provided by operating activities	151,813	143,895	139,101
Cash flows from investing activities:			
Capital expenditures	(162,723)	(143,033)	(323,153)
Acquisition of oil and gas properties, net of cash acquired	(158,051)	—	—
Deconsolidation/change in ownership effect on cash and cash equivalents	(3,527)	—	—
Decrease (increase) in restricted cash	—	—	(874)
Proceeds from sale of leases to partnerships	—	—	448
Proceeds from sale of leaseholds/assets	23,369	755	538
Net cash used in investing activities	(300,932)	(142,278)	(323,041)
Cash flows from financing activities:			
Proceeds from credit facility	414,500	285,086	419,000

Proceeds from senior notes	115,000	—	200,101
Payment of credit facility	(494,500)	(399,586)	(459,500)
Payment of debt issuance costs	(8,541)	(9,249)	(5,571)
Proceeds from sale of equity, net of issuance costs	125,506	48,490	—
Proceeds from exercise of stock options	—	—	627
Excess tax benefits from stock-based compensation	293	—	1,031
Contribution from noncontrolling interest	20,077	55,000	—
Purchase of treasury stock	(788)	(364)	(5,549)
Net cash provided by (used in) financing activities	171,547	(20,623)	150,139
Net increase (decrease) in cash and cash equivalents	22,428	(19,006)	(33,801)
Cash and cash equivalents, beginning of year	31,944	50,950	84,751
Cash and cash equivalents, end of year	$54,372	$31,944	$50,950

See accompanying Notes to Consolidated Financial Statements

Petroleum Development Corporation
(dba PDC Energy)
Consolidated Statements of Cash Flows - Continued
(in thousands)

Year Ended December 31,	2010	2009	2008
Supplemental cash flow information:			
Cash payments (receipts) for:			
Interest, net of capitalized interest	$28,335	$32,014	$19,200
Income taxes, net of refunds	(27,322)	(3,355)	(530)
Non-cash investing activities:			
Change in accounts payable related to purchases of properties and equipment	$15,787	$(36,765)	$8,197
Change in asset retirement obligation, with a corresponding increase to natural gas and crude oil properties, net of disposals	3,624	5,110	1,153
Non-cash financiang activities:			
Change in paid-in capital related to convertible debt, net of tax of $7,873	$12,850	$—	$—

See accompanying Notes to Consolidated Financial Statements
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Petroleum Development Corporation
(dba PDC Energy)
Consolidated Statements of Equity
(in thousands, except share and per share data)

Year Ended December 31,	2010	2009	2008
Common shares, issued:			
Shares beginning of year	19,242,219	14,871,870	14,907,679
Adjust prior conversion of predecessor shares	—	—	100
Shares issued pursuant to sale of equity	4,140,000	4,312,500	—
Exercise of stock options	—	—	25,699
Issuance of stock awards, net of forfeitures	110,680	79,246	21,863
Retirement of treasury shares	(30,573)	(21,397)	(83,471)
Shares end of year	23,462,326	19,242,219	14,871,870
Treasury shares:			
Shares beginning of year	(8,273)	(7,066)	(5,894)
Purchase of treasury shares	(30,573)	(21,397)	(83,471)
Retirement of treasury shares	30,573	21,397	83,471
Non-employee directors' deferred compensation plan	5,335	(1,207)	(1,172)
Shares end of year	(2,938)	(8,273)	(7,066)
Common shares outstanding	23,459,388	19,233,946	14,864,804
Equity:			
Shareholders' equity			
Preferred shares, par value $0.01 per share:			
Balance beginning and end of year	$—	$—	$—
Common shares, par value $0.01 per share:			
Balance beginning of year	192	149	149
Shares issued pursuant to sale of equity	41	43	—
Issuance of stock awards, net of forfeitures	2	—	—
Balance end of year	235	192	149
Additional paid-in capital:			
Balance beginning of year	64,406	5,818	2,559
Proceeds from sale of equity, net of issuance costs of $6,974	125,465	48,447	—
Convertible debt discount, net of issuance costs of $685 and tax of $7,873	12,165	—	—
Issuance of stock awards, net of forfeitures	(2)	—	—
Exercise of stock options	—	—	627
Stock-based compensation expense	5,314	5,935	6,702
Retirement of treasury shares	(788)	(364)	(5,101)
Tax benefit (detriment) of stock-based compensation	(164)	(1,630)	1,031
Contribution from noncontrolling interest	20,077	55,000	—
Effect of PDCM deconsolidation/change in ownership interest	(17,275)	(48,800)	—
Balance end of year	209,198	64,406	5,818
Retained earnings:			
Balance beginning of year	426,629	505,906	393,044
Retirement of treasury shares	—	—	(447)
Net income (loss) attributable to shareholders	6,214	(79,277)	113,309
Balance end of year	432,843	426,629	505,906

Treasury shares, at cost:			
Balance beginning of year	(312)	(292)	(226)
Purchase of treasury shares	(788)	(364)	(5,549)
Retirement of treasury shares	788	364	5,549
Non-employee directors' deferred compensation plan	201	(20)	(66)
Balance end of year	(111)	(312)	(292)
Total shareholders' equity	642,165	490,915	511,581
Noncontrolling interests in subsidiaries			
Balance beginning of year	47,678	694	759
Noncontrolling interest in PDC Mountaineer, LLC	(47,322)	48,800	—
Net loss attributed to noncontrolling interest in subsidiary	(280)	(1,816)	(65)
Balance end of year	76	47,678	694
Total noncontrolling interests in subsidiaries	76	47,678	694
Total Equity	$642,241	$538,593	$512,275

See accompanying Notes to Consolidated Financial Statements

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 - NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Petroleum Development Corporation ("PDC," "PDC Energy," "we," "us" or "the Company") is a domestic independent natural gas and crude oil company engaged in the exploration for and the acquisition, development, production and marketing of natural gas, natural gas liquids ("NGLs") and crude oil. As of December 31, 2010, we owned an interest in and operated approximately 5,000 gross wells located primarily in the Rocky Mountain Region and the Permian and Appalachian Basins. We are engaged in two business segments: (1) natural gas and crude oil sales and (2) natural gas marketing.

The consolidated financial statements include the accounts of PDC, our wholly owned subsidiaries, an entity in which we have a controlling financial interest and our proportionate share of PDC Mountaineer, LLC ("PDCM") and 29 of our affiliated partnerships. Pursuant to the proportionate consolidation method, our accompanying consolidated financial statements include our pro rata share of assets, liabilities, revenues and expenses of the entities which we proportionately consolidate. All material intercompany accounts and transactions have been eliminated in consolidation.

On January 1, 2010, pursuant to the adoption of new accounting changes related to variable interest entities, PDCM, a variable interest entity, was deconsolidated from 100% and proportionately consolidated at 67.4%, representing only our ownership interest. On April 1 and November 1, 2010, our joint venture partner made cash capital contributions to PDCM of $28 million and $7 million, respectively. The contributions resulted in our original ownership interest decreasing from 67.4% to 57.8% then to 55.8%. Each change in our ownership interest resulted in a decrease in our proportionate share of net assets and future earnings. As of December 31, 2010, PDCM was consolidated at 55.8% and the 29 partnerships were consolidated at varying percentages. See Notes 2 and 15 for the impact of new accounting changes on the consolidation of PDCM on January 1, 2010.

The preparation of our consolidated financial statements in accordance with generally accepted accounting principles in the United States of America ("U.S.") 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 natural gas, NGL and crude oil sales revenue, natural gas, NGL and crude oil reserves, future cash flows from natural gas and crude oil properties, valuation of derivative instruments and valuation of deferred income tax assets.

Certain reclassifications have been made to prior period financial statements to conform to the current year presentation. The reclassifications are directly related to our discontinued operations. The reclassifications had no impact on previously reported cash flows, net income, earnings per share or shareholders' equity. See Note 13 for additional information regarding our discontinued operations.

NOTE 2 - SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation and Accounting for Variable Interest Entities. A variable interest entity ("VIE") is consolidated if it is determined that we are the entity's primary beneficiary. The primary beneficiary of a VIE has both the following characteristics: (1) the power to direct the activities of the VIE that most significantly impact the entity's economic performance and (2) the obligation to absorb losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE. In determining whether we are the primary beneficiary of a VIE, we consider a number of factors, including our ability to direct the activities that most significantly affect the entity's economic success and our contractual rights and responsibilities under arrangements with the entity. As certain events occur, we may reconsider whether those events have caused us to become the primary beneficiary. A reconsideration event may also occur when we acquire new or additional interests in a VIE. As of December 31, 2010, we were not the primary beneficiary of a VIE. As of December 31, 2009, we consolidated PDCM, a VIE, as we had determined, prior to the adoption of new accounting changes, that we were the primary beneficiary. See Recent Accounting Standards below and Note 15 for the impact of new accounting changes on the deconsolidation of PDCM on January 1, 2010.

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

The following table presents the carrying amount and classification of our proportionate share of PDCM's assets and liabilities included in our balance sheets.

	As of December 31, 2010	2009
	(in thousands)	
Cash and cash equivalents	$1,560	$9,428
Other current assets	3,206	4,504
Property, plant and equipment, net	101,679	158,788
Other assets	1,986	1,499
Total assets	$108,431	$174,219
Other current liabilities	$4,641	$12,224
Asset retirement obligation	8,681	14,769
Other liabilities	1,370	2,068
Noncontrolling interest	—	47,322
Equity	93,739	97,836
Total liabilities and equity	$108,431	$174,219

Cash Equivalents. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents.

Inventory. Inventory consists of crude oil, stated at the lower of cost to produce or market, and other production supplies intended to be used in our natural gas and crude oil operations. As of December 31, 2010 and 2009, inventory of $1.4 million and $0.8 million, respectively, is included in prepaid expense and other current assets on the balance sheets.

Derivative Financial Instruments. We are exposed to the effect of market fluctuations in the prices of natural gas and crude oil. We employ established policies and procedures to manage a portion of the risks associated with these market fluctuations using commodity derivative instruments. Our policy prohibits the use of natural gas and crude oil derivative instruments for speculative purposes.

All derivative assets and liabilities are recorded on the balance sheets at fair value. We have elected not to designate any of our derivative instruments as hedges. Classification of realized and unrealized gains and losses resulting from maturities and changes in fair value of open derivatives depends on the purpose for issuing or holding the derivative. Accordingly, changes in the fair value of our derivative instruments are recorded in the statements of operations, with the exception of changes in fair value related to those derivatives we designated to our affiliated partnerships. Changes in the fair value of derivative instruments related to our natural gas and crude oil sales are recorded in commodity price risk management, net. Changes in the fair value of derivative instruments related to our natural gas marketing segment are recorded in sales from and cost of natural gas marketing. Changes in the fair value of the derivative instruments designated to our affiliated partnerships are recorded on the balance sheets in accounts payable affiliates and accounts receivable affiliates. As positions designated to our affiliated partnerships settle, the realized gains and losses are netted for distribution. Net realized gains are paid to the partnerships and net realized losses are deducted from the partnerships' cash distributions from production. The affiliated partnerships bear their designated share of counterparty risk.

The validation of the derivative instrument'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. See Notes 3 and 4 for a discussion of our derivative fair value measurements and a summary fair value table of our open positions as of December 31, 2010 and 2009, respectively.

Properties and Equipment. Significant accounting polices related to our properties and equipment are discussed below.

Natural Gas and Crude Oil Properties. We account for our natural gas and crude oil properties under the successful efforts method of accounting. Costs of proved developed producing properties, successful exploratory wells and developmental dry hole costs are capitalized and depreciated or depleted by the unit-of-production method based on estimated proved developed producing reserves. Property acquisition costs are depreciated or depleted on the unit-of-production method based on estimated proved reserves. We calculate quarterly depreciation, depletion and amortization ("DD&A") expense by using our estimated prior period-end reserves as the denominator, with the exception of our fourth quarter where we use the year-end reserve estimate adjusted to add back fourth quarter production. Upon the 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 recognized in the statement of operations as a gain or loss. Upon the sale of individual wells, the proceeds are credited to accumulated DD&A.

PETROLEUM DEVELOPMENT CORPORATION
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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 prior to the issuance of the financial statements, the costs incurred, including costs for plugging, prior to the end of the reporting period are expensed to exploration expense. If we are unable to make a final determination about the productive status of a well prior to issuance of the financial statements, the costs associated with the well are 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 we are able to make a final determination of a well’s productive status, the same well is removed from the suspended well status and the proper accounting treatment is recorded. See Note 6 for disclosure related to changes in our capitalized exploratory well costs from January 1, 2008, to December 31, 2010.

Proved Property Impairment. We assess our producing natural gas and crude oil properties for possible impairment, upon a triggering event, 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 natural gas and crude oil. Certain events, including but not limited to, downward revisions in estimates to our reserve quantities, expectations of falling commodity prices or rising operating costs, could result in a triggering event and, therefore, a possible impairment of our proved natural gas and crude oil properties. If net capitalized costs exceed undiscounted future net cash flows, the measurement of impairment is based on estimated fair value utilizing a future discounted cash flows analysis and is measured by the amount by which the net capitalized costs exceed their fair value. In May 2010, pursuant to our entry into an agreement to sell our Michigan assets, we reclassified our Michigan assets as held for sale. See Note 13. The agreement to sell these assets, a triggering event, required us to perform an impairment test as long lived assets held for sale are required to be measured at the lower of carrying value or fair value less costs to sell. We compared the transactional sales price, considered a Level 3 input, less costs to sell to the carrying value of our Michigan net assets. Since the net carrying value exceeded the net sales price, we were required to recognize an impairment charge by reducing the carrying value of the net assets to reflect the net sales price. As a result, in the second quarter of 2010, we recorded an impairment charge of $4.7 million related to the sale of our Michigan assets. The impairment charge is reflected in discontinued operations in the statement of operations.

Unproved Property Impairment. 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 natural gas and crude oil 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. Impairment charges are recorded in the statements of operations as a component of exploration expense.

The following table presents expiration, impairment and amortization charges recorded for unproved properties.

	As of December 31,		
	2010	2009	2008

	(in thousands)		
Individually significant unproved properties (1)	$1,477	$982	$9,165
Insignificant unproved properties (2)	5,004	3,126	3,633
Total	$6,481	$4,108	$12,798

(1) 2008 includes an impairment of $7.3 million related to our properties in the Fort Worth Basin.

(2) The increase in amortization of insignificant unproved properties in 2010 was primarily due to our lack of drilling in the NECO area and the Pennsylvania portion of the Appalachian Basin.

Other Property and Equipment. The following table presents 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	20 - 30 years

Other property and equipment are carried at cost. Depreciation is provided principally on the straight-line method over the assets estimated useful lives. We review these long-lived assets 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

PETROLEUM DEVELOPMENT CORPORATION
(dba PDC Energy)
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

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. Impairments recognized in 2010 and 2009 were immaterial. No impairments were recorded in 2008.

Maintenance and repairs on other property and equipment 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 DD&A are removed from the accounts, the proceeds are applied thereto and any resulting gain or loss is reflected in income. Total depreciation expense related to other property and equipment was $7.5 million, $8.1 million and $7.6 million in 2010, 2009 and 2008, respectively.

Capitalized Interest. Interest costs are capitalized as part of the historical cost of acquiring assets. Investments in unproved natural gas and crude oil properties and major development projects, on which DD&A 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 outstanding 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. Capitalized interest totaled $0.3 million, $0.8 million and $2.6 million in 2010, 2009 and 2008, respectively.

Production Tax Liability. Production tax liability represents estimated taxes, primarily severance, ad valorem and property, to be paid to the states and counties in which we produce natural gas, NGLs and crude oil, including the production of our affiliated partnerships. Our share of these taxes is expensed to production costs. The partnerships' share, not owned by us, is recognized as a receivable in accounts receivable affiliates on the balance sheets.

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 basis. 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. As of December 31, 2010, we had no valuation allowance. As of December 31, 2009, we had a valuation allowance of $0.7 million.

Debt Issuance Costs. Debt issuance costs are capitalized and amortized over the life of the respective borrowings using the effective interest method. As of December 31, 2010 and 2009, included in other assets was $14.6 million and $10.7 million, respectively, related to debt issuance costs. The December 31, 2010, amount included $3.1 million in costs related to the issuance of our 3.25% convertible senior notes due 2016, $3.9 million related to our 12% senior notes due 2018 and $7.6 million related to our bank credit facilities.

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 production costs. The initial capitalized costs are depleted over the useful lives of the related assets, through charges to DD&A expense. 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 changes in retirement costs or the estimated timing of settling asset retirement obligations. See Note 9 for a reconciliation of the changes in our asset retirement obligation from January 1, 2009, to December 31, 2010.

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 12. 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 additional paid-in-capital, with any remaining excess cost being charged to retained earnings.

Revenue Recognition. Significant accounting polices related to our revenue recognition are discussed below.

Natural gas, NGL and crude oil sales. Natural gas, NGL and crude oil revenues are recognized when production is sold to a purchaser at a fixed or determinable price, delivery has occurred, rights and responsibility of ownership have transferred and collection of revenue is reasonably assured. 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. The majority of our natural gas and NGLs in Colorado are sold on a long-term basis ranging from 15 years to the life of the lease. Sales of natural gas and NGLs in other regions, along with crude oil, are sold 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 the natural gas and prevailing supply and demand conditions.

PETROLEUM DEVELOPMENT CORPORATION
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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - Continued

Well operations and pipeline income. We are paid a monthly operating fee for each well we operate and the natural gas transported for outside owners including the limited partnerships we sponsored. Well operations and pipeline income is 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.

Natural gas marketing. Natural gas marketing is reported on the gross method of accounting, based on the nature of the agreements between Riley Natural Gas ("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 are included in sales from or cost of natural gas marketing, as applicable.

Stock-Based Compensation. Stock-based compensation is recognized in our financial statements based on the fair value, on the date of grant or modification, of the equity instrument awarded. Stock-based compensation expense is 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 natural gas and crude oil exploration and development activities, such amounts may be capitalized to properties and equipment. Amounts not capitalized to properties and equipment are recognized in the related cost and expense line item in the statement of operations. No amounts for stock-based compensation were capitalized in 2010, 2009 or 2008.

Earnings Per Share. Basic earnings (loss) per common share ("EPS") is computed by dividing net income (loss), the numerator, by the weighted-average number of common shares outstanding for the period, the denominator. Diluted EPS is similarly computed except that the denominator includes the effect, using the treasury stock method, of our unamortized portion of restricted stock, outstanding stock appreciation rights ("SARs"), stock options, convertible notes and shares held pursuant to our non-employee director deferred compensation plan, if including such potential shares of common stock is dilutive.

The following table presents a reconciliation of the weighted average diluted shares outstanding.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Weighted average common shares outstanding - basic	19,674	16,448	14,736
Dilutive effect of share-based compensation:			
Restricted stock	119	—	71
SARs	21	—	—
Stock options	—	—	35
Non employee director deferred compensation	7	—	6
Weighted average common and common share equivalents outstanding - diluted	19,821	16,448	14,848

For 2009, the weighted average common shares outstanding for both basic and diluted were the same, as the effect of dilutive securities were anti-dilutive due to our net loss. The following table presents the weighted average common share equivalents excluded from the calculation of diluted earnings (loss) per share due to their anti-dilutive effect.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Weighted average common share equivalents excluded from diluted earnings per share due to their anti-dilutive effect:			
Restricted stock	204	284	73
Stock options	10	10	—
Non employee director deferred compensation	—	8	—
Total anti-dilutive common share equivalents	214	302	73

In November 2010, we issued 115,000 convertible senior notes, $1,000 principal amount, that give the holders the right to convert the principal amount into 2.7 million common shares at a conversion price of $42.40 per share. These convertible notes could have a dilutive impact on our earnings per share if the average market share price exceeds the conversion price. The table above does not include those shares issuable upon conversion as the average share price of our common stock did not exceed the conversion price during the period.

Recent Accounting Standards. The following standards have been recently adopted:

Consolidation - Variable Interest Entities. In June 2009, the Financial Accounting Standards Board ("FASB") issued changes regarding an entity's analysis to determine whether any of its variable interests constitute controlling financial interests in a variable interest entity. This analysis identifies the primary beneficiary of a variable interest entity as the enterprise that has both of the following characteristics:

- the power to direct the activities of a variable interest entity that most significantly impact the entity's economic performance; and
- the obligation to absorb losses of the entity that could potentially be significant to the variable interest entity or the right to receive benefits from the entity that could potentially be significant to the variable interest entity.

Additionally, the entity is required to assess whether it has an implicit financial responsibility to ensure that a variable interest entity operates as designed when determining whether it has the power to direct the activities of the variable interest entity that most significantly impact the entity's economic performance. The guidance also requires ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity. We adopted these changes effective January 1, 2010. Upon adoption, we deconsolidated PDCM as we determined that we were not the primary beneficiary based upon the fact that power over the activities that significantly impact this joint venture is equally shared with our investment partner. No cumulative effect adjustment to retained earnings was recognized upon adoption. See Note 15 for the impact of adoption on our financial statements.

Fair Value Measurements and Disclosures. In January 2010, the FASB issued changes clarifying existing disclosure requirements related to fair value measurements. The update also added a new requirement to disclose fair value transfers in and out of Levels 1 and 2 and describe the reasons for the transfers. The adoption of these changes as of January 1, 2010, did not have a material impact on our financial statements.

The following standards have recently been issued:

Fair Value Measurements and Disclosures. In January 2010, the FASB issued changes related to fair value measurements requiring gross presentation of activities within the Level 3 roll forward, whereby entities must present separately information about purchases, sales, issuances and settlements. These changes will be effective for our financial statements issued for annual reporting periods beginning after December 15, 2010. We do not expect the adoption of this change to have a material impact on our financial statements.

NOTE 3 - FAIR VALUE OF FINANCIAL INSTRUMENTS

Derivative Financial Instruments

Determination of fair value. Our fair value measurements are estimated pursuant to a fair value hierarchy that requires us 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 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, and may affect the valuation of the assets and liabilities and their placement within the fair value hierarchy levels. 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. Included in Level 1 are our commodity derivative instruments 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. Included in Level 3 are our commodity derivative instruments for CIG and PEPL-based natural gas swaps, crude oil swaps, natural gas and crude oil collars, physical sales and purchases and our natural gas basis protection derivative instruments.

Derivative Financial Instruments. We measure the fair value of our derivative instruments 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 nonperformance risk on our own liabilities as well as the credit standing of our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. We have evaluated the credit risk of the counterparties holding our derivative assets using relevant credit market default

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rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, we have determined that the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is insignificant. Validation of our contracts' 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. While we believe these valuation methods are appropriate and consistent with those 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.

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 December 31, 2010 and 2009.

	As of December 31, 2010			2009		
	Quoted Prices in Active Markets (Level 1) (in thousands)	Significant Unobservable Inputs (Level 3)	Total	Quoted Prices in Active Markets (Level 1)	Significant Unobservable Inputs (Level 3)	Total
Assets:						
Commodity based derivatives	$64,138	$23,168	$87,306	$25,598	$36,796	$62,394
Basis protection derivative contracts	—	111	111	—	57	57
Total assets	64,138	23,279	87,417	25,598	36,853	62,451
Liabilities:						
Commodity based derivatives	51	20,011	20,062	3,140	9,932	13,072
Basis protection derivative contracts	—	46,580	46,580	—	55,915	55,915
Total liabilities	51	66,591	66,642	3,140	65,847	68,987
Net asset (liability)	$64,087	$(43,312)	$20,775	$22,458	$(28,994)	$(6,536)

The following table presents a reconciliation of our Level 3 fair value measurements.

	2010 (in thousands)	2009
Fair value, net asset (liability) beginning of year, January 1	$(28,994)	$134,849
Changes in fair value included in statement of operations line item:		
Commodity price risk management gain (loss), net	14,999	(23,243)
Sales from natural gas marketing	580	(380)
Cost of natural gas marketing	(5,113)	3,718
Changes in fair value included in balance sheet line item (1):		
Accounts receivable affiliates	2,544	(18,960)

Accounts payable affiliates	(5,826)	(29,292)
Settlements included in statement of operations line items:		
Commodity price risk management gain (loss), net	(26,487)	—
Sales from natural gas marketing	(484)	(95,678)
Cost of natural gas marketing	5,469	(8)
Fair value, net liability end of year, December 31	$(43,312)	$(28,994)
Changes in unrealized gains (losses) relating to assets (liabilities) still held as of December 31, 2010, included in statement of operations line item:		
Commodity price risk management gain (loss), net	$8,040	$(38,634)
Sales from natural gas marketing	54	29
Cost of natural gas marketing	(997)	(1,083)
	$7,097	$(39,688)

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(1) Represents the change in fair value related to derivative instruments entered into by us and designated to our affiliated partnerships.

See Note 4 for additional disclosure related to our derivative financial instruments.

Non-Derivative Financial Assets and Liabilities

The carrying values of the financial instruments comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

The portion of our long-term debt related to our credit facility approximates fair value due to the variable nature of its related interest rate. We have not elected to account for the portion of our long-term debt related to our senior notes under the fair value option; however, as of December 31, 2010, we estimate the fair value of the portion of our long-term debt related to the 3.25% convertible senior notes due 2015 to be $137.3 million or 119.4% of par value and the portion related to our 12% senior notes due 2018 to be $226.5 million or 111.6% of par value as of December 31, 2010. We determined these valuations based upon measurements of trading activity and broker/dealer quotes, respectively.

See Note 2, subsections Property and Equipment, Natural Gas and Crude Oil Properties and Asset Retirement Obligations for a discussion of how we determined fair value for these obligations.

NOTE 4 - DERIVATIVE FINANCIAL INSTRUMENTS

Our results of operations and operating cash flows are affected by changes in market prices for natural gas and crude oil. To mitigate a portion of our exposure to adverse market changes, we utilize the following economic hedging strategies for each of our business segments.

- For natural gas and crude oil sales, we enter into derivative contracts to protect against price declines in future periods. While we structure these derivatives 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 increases in the physical market.
- For natural gas marketing, we enter into fixed-price physical purchase and sale agreements that qualify as derivative contracts. In order to offset the fixed-price physical derivatives in our natural gas marketing, 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.

We believe our derivative instruments continue to be effective in achieving the risk management objectives for which they were intended. As of December 31, 2010, we had derivative instruments in place for a portion of our anticipated production through 2013 for a total of 37,862.9 BBtu of natural gas and 2,071.7 MBbls of crude oil.

As of December 31, 2010, our derivative instruments were comprised of commodity floors, collars and swaps, basis protection swaps and physical sales and purchases.

- Floor options (puts) are arrangements where, if the index 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 index price from the counterparty. If the index price exceeds the fixed put strike price, then no payment is due from us to the counterparty.
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Collars contain a fixed floor price and ceiling price (call). If the index 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 index price from the counterparty. If the index 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 index price to the counterparty. If the index price is between the put and call strike price, no payments are due to or from the counterparty.

- Swaps are arrangements that guarantee a fixed price. If the index price is below the fixed contract price, we receive the market price from the purchaser and receive the difference between the index price and the fixed contract price from the counterparty. If the index price is above the fixed contract price, we receive the market price from the purchaser and pay the difference between the index price and the fixed contract price to the counterparty. If the index price and contract price are the same, no payment is due to or from the counterparty.
- Basis protection swaps are arrangements that guarantee a price differential for natural gas from a specified delivery point. For CIG-basis protection swaps, which have negative differentials to NYMEX, we receive a payment from the counterparty if the price differential is greater than the stated terms of the contract and pay the counterparty if the price differential is less than the stated terms of the contract. If the market price and contract price are the same, no payment is due to or from the counterparty.
- Physical sales and purchases are derivatives for fixed-priced physical transactions where we sell or purchase third party supply at fixed rates. These physical derivatives are offset by financial swaps: for a physical sale the offset is a swap purchase and for a physical purchase the offset is a swap sale.

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The following table presents the location and fair value amounts of our derivative instruments on the balance sheets as of December 31, 2010 and 2009.

Derivatives instruments not designated as hedges (1):		Balance sheet line item	Fair Value As of December 31, 2010	2009
			(in thousands)	
Derivative assets: (2)	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$41,068	$39,107
	Related to natural gas marketing	Fair value of derivatives	1,811	3,077
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	74	39
			42,953	42,223
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	44,381	19,680
	Related to natural gas marketing	Fair value of derivatives	46	530
	Basis protection contracts			
	Related to natural gas marketing	Fair value of derivatives	37	18
			44,464	20,228
Total derivative assets			$87,417	$62,451
Derivative liabilities: (3)	Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	$12,312	$2,451
	Related to natural gas marketing	Fair value of derivatives	1,492	2,626
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	16,187	15,127
	Related to natural gas marketing	Fair value of derivatives	7	4
			29,998	20,208
	Non Current			
	Commodity contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	6,228	7,572
	Related to natural gas marketing	Fair value of derivatives	30	423
	Basis protection contracts			
	Related to natural gas and crude oil sales	Fair value of derivatives	30,386	40,784
			36,644	48,779
Total derivative liabilities			$66,642	$68,987

(1) As of December 31, 2010, and December 31, 2009, none of our derivative instruments were designated as hedges.
(2) Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding payable to our affiliated partnerships of $20.3 million and $13.4 million as of December 31, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative assets.
(3) Includes derivative positions that have been designated to our affiliated partnerships; accordingly, our accompanying balance sheets include a corresponding receivable from our affiliated partnerships of $14.6 million and $21 million as of December 31, 2010, and December 31, 2009, respectively, representing their proportionate share of the derivative liabilities.

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The following table presents the impact of our derivative instruments on our statements of operations.

	Year Ended December 31, 2010			2009			2008		
Statement of operations line item	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total	Reclassification of Realized Gains (Losses) Included in Prior Periods Unrealized	Realized and Unrealized Gains (Losses) For the Current Period	Total
	(in thousands)								
Commodity price risk management gain (loss), net									
Realized gains (losses)	$20,148	$26,947	$47,095	$84,655	$22,690	$107,345	$(549)	$10,036	$9,487
Unrealized gains (losses)	(20,148)	32,944	12,796	(84,655)	(32,743)	(117,398)	549	117,802	118,351
Total commodity price risk management gain (loss), net (1)	$—	$59,891	$59,891	$—	$(10,053)	$(10,053)	$—	$127,838	$127,838
Sales from natural gas marketing									
Realized gains (losses)	$2,390	$3,991	$6,381	$4,798	$3,744	$8,542	$1,447	$(3,213)	$(1,766)
Unrealized gains (losses)	(2,390)	1,745	(645)	(4,798)	1,295	(3,503)	(1,447)	6,061	4,614
Total sales from natural gas marketing (2)	$—	$5,736	$5,736	$—	$5,039	$5,039	$—	$2,848	$2,848
Cost of natural gas marketing									
Realized gains (losses)	$(1,905)	$(3,996)	$(5,901)	$(4,719)	$(4,127)	$(8,846)	$(898)	$3,996	$3,098
Unrealized gains (losses)	1,905	(1,431)	474	4,719	(441)	4,278	898	(6,327)	(5,429)
Total cost of natural gas marketing (2)	$—	$(5,427)	$(5,427)	$—	$(4,568)	$(4,568)	$—	$(2,331)	$(2,331)

(1) Represents realized and unrealized gains and losses on derivative instruments related to natural gas and crude oil sales.
(2) Represents realized and unrealized gains and losses on derivative instruments related to natural gas marketing.

NOTE 5 - CONCENTRATION OF RISK

Accounts Receivable. The following table presents the components of accounts receivable, net.

	As of December 31, 2010	2009
	(in thousands)	
Natural gas, NGL and crude oil sales	$27,730	$19,527
Derivative counterparties	2,020	12,887
Joint interest billings	12,142	10,260
Natural gas marketing	8,279	9,297
Other	4,493	5,068
Allowance for doubtful accounts	(686)	(548)
Accounts receivable, net	$53,978	$56,491

Our accounts receivable are primarily from purchasers of our natural gas, NGL and crude oil production, derivative counterparties and other third parties which own working interests in the properties that we operate. Inherent to our industry is the concentration of natural gas, NGL and crude oil sales to a few customers. This industry concentration has the potential to impact our overall exposure to credit risk, either positively or negatively, in that our customers may be similarly affected by changes in economic and financial conditions, commodity prices or other conditions. We record an allowance for doubtful accounts for receivables that we estimate to be uncollectible. In making our

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estimate, we consider, among other things, our historical write-offs and overall creditworthiness of our customers. Further, consideration is given to well production data for receivables related to well operations. It is reasonably possible that our estimate of uncollectible amounts will change periodically. As of December 31, 2010, Suncor Energy Marketing, Inc. represented 13.7% of our accounts receivable balance.

Major Customers. The following table presents the individual customers constituting 10% or more of total revenues.

Customer	Percent of Total Revenues Year Ended December 31, 2010		2009		2008	
Suncor Energy Marketing, Inc.	19.6	%	18.6	%	0.2	%
Williams Production RMT Company	12.5	%	16.1	%	12.4	%
DCP Midstream, LP	9.6	%	11.9	%	6.6	%
Teppco Crude Oil, LLC	0.6	%	2.1	%	10.8	%

Derivative Counterparties. A significant portion of our liquidity is concentrated in derivative instruments that enable us to manage a portion of our exposure to price volatility from producing natural gas and crude oil. These arrangements expose us to credit risk of nonperformance by our counterparties. We primarily use financial institutions, who are also major lenders in our credit facility agreement, as counterparties to our derivative contracts. To date, we have had no counterparty default losses. We have evaluated the credit risk of our derivative assets from our counterparties using relevant credit market default rates, giving consideration to amounts outstanding for each counterparty and the duration of each outstanding derivative position. Based on our evaluation, the impact of the nonperformance of our counterparties on the fair value of our derivative instruments is not significant.

The following table presents the counterparties that expose us to credit risk as of December 31, 2010, with regard to our derivative assets.

Counterparty Name	Fair Value of Derivative Assets As of December 31, 2010 (in thousands)
JPMorgan Chase Bank, N.A. (1)	$39,914
Crèdit Agricole CIB (1)	28,301
Wells Fargo Bank, N.A. (1)	15,665
Various (2)	3,537
Total	$87,417

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(1)Major lender in our credit facility, see Note 8.
(2)Represents a total of 16 counterparties, including two lenders in our credit facility.

NOTE 6 - PROPERTIES AND EQUIPMENT

As of December 31,

	2010	2009
	(in thousands)	
Properties and equipment, net:		
Natural gas and crude oil properties		
Proved	$1,429,667	$1,266,921
Unproved	79,053	36,858
Total natural gas and crude oil properties	1,508,720	1,303,779
Pipelines and related facilities	34,262	36,910
Transportation and other equipment	32,410	33,432
Land and buildings	13,379	14,699
Construction in progress	42,128	9,131
	1,630,899	1,397,951
Accumulated DD&A	(510,861)	(424,293)
Properties and equipment, net (1)	$1,120,038	$973,658

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(1) In 2010, as a result of the deconsolidation of and our change in ownership interest in PDCM, properties and equipment were reduced by $51.8 million, net of accumulated DD&A of $15.7 million, from December 31, 2009. See Note 15.

Suspended Well Costs

The following table presents the capitalized exploratory well costs pending determination of proved reserves and included in properties and equipment on the balance sheets.

	2010	2009	2008
	(in thousands, except for number of wells)		
Balance beginning of year, January 1	$1,174	$1,180	$2,300
Deconsolidation of PDCM and change in ownership interest	(462)	—	—
Additions to capitalized exploratory well costs pending the determination of proved reserves	4,353	10,226	15,644
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(2,231)	(9,914)	(10,259)
Capitalized exploratory well costs charged to expense	(537)	(318)	(6,505)
Balance end of year, December 31	$2,297	$1,174	$1,180
Number of wells pending determination at December 31	3	2	6

As of December 31, 2010, none of the three suspended wells awaiting the determination of proved reserves have been capitalized for a period greater than one year after the completion of drilling.

NOTE 7 - INCOME TAXES

The table below presents the components of tax expense (benefit) from continuing operations for the years presented.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Current:			
Federal	$(1,119)	$(29,071)	$172
State	947	312	(4,258)
Total current income taxes	(172)	(28,759)	(4,086)
Deferred:			
Federal	3,990	(11,546)	57,637
State	(2,626)	(4,749)	3,786
Total deferred income taxes	1,364	(16,295)	61,423
	$1,192	$(45,054)	$57,337

Income tax provision (benefit) from
continuing operations

For the years ended December 31, 2010, 2009 and 2008, we elected to currently expense approximately $8.5 million, $80 million and $30 million, respectively, of intangible drilling costs ("IDC"). We also continued to utilize other tax deferral strategies such as statutory bonus and accelerated depreciation, special partnership formation statutes and regulations and Internal Revenue Code ("IRC") Section 1031 like-kind exchange ("LKE") strategies to reduce our current tax expense, resulting in a correspondingly higher deferred tax expense. As a result of these elections and deferral strategies, we have generated a federal tax loss, which may be carried back to 2008. This benefit is reflected in the 2010 current federal provision. The Worker, Homeownership, and Business Assistance Act of 2009 increased the statutory carry-back from two years to five years for losses incurred in 2008 and 2009. We carried back our 2009 tax loss to the 2005 and 2006 tax years, generating a benefit of $25.9 million, which was received in the second quarter of 2010. The benefit is reflected in the 2009 current federal provision.

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The following table presents a reconciliation of the statutory rate to the effective tax rate.

	Year Ended December, 31, 2010		2009		2008	
Statutory tax rate	35.0	%	35.0	%	35.0	%
State income tax, net	1.6	%	3.3	%	3.1	%
Percentage depletion	(9.3	)%	0.5	%	(0.7	)%
Non-deductible compensation	3.6	%	0.1	%	—	%
State deferred rate change (discrete)	(21.6	)%	(0.9	)%	(0.6	)%
Unrecognized tax benefits	2.0	%	0.7	%	0.3	%
State tax credits	(2.7	)%	0.3	%	(0.2	)%
2007-2009 federal return examination adjustments	3.9	%	—	%	—	%
Non-decuctible expenditures - PDCM	—	%	(1.8	)%	—	%
Other	2.2	%	(1.2	)%	(1.8	)%
Effective tax rate	14.7	%	36.0	%	35.1	%

The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2010 and 2009, are presented below.

	As of December 31, 2010 (in thousands)		2009	
Deferred tax assets:				
Allowance for lease impairment	$5,502		$5,751	
Provision for underpayment of natural gas sales	2,711		1,130	
Deferred compensation	3,986		3,277	
Asset retirement obligations	6,716		5,189	
State NOL and tax credit carryforwards, net	4,624		4,664	
Percentage depletion - carryforward	2,422		811	
Alternative minimum tax - credit carryforward	2,069		—	
Dry hole costs	1,707		—	
Other	2,247		1,657	
Total gross deferred tax assets	31,984		22,479	
Less valuation allowance	—		(747	)
Deferred tax assets	31,984		21,732	
Deferred tax liabilities:				
Properties and equipment	(171,795	)	(170,161	)
Investment in PDCM	(31,149	)	(23,935	)
Unrealized gains - derivatives	(3,082	)	(230	)
Convertible debt	(7,873	)	—	
Future state liabilities	—		(270	)
Total gross deferred tax liabilities	(213,899	)	(194,596	)
Net deferred tax liability	$(181,915	)	$(172,864	)

Classification in the Consolidated Balance Sheets:		
Prepaid expenses and other current assets	$6,084	$5,148
Deferred income taxes	(187,999)	(178,012)
Net deferred tax liability	$(181,915)	$(172,864)

Deferred tax liabilities for properties and equipment increased in 2010, primarily as a result of our election to expense $8.5 million of IDC for income tax purposes, and also due to our continued utilization of statutory provisions for bonus and accelerated tax depreciation. In addition, the application of LKE provisions to our sale of Michigan properties resulted in a $6.5 million of tax deferral. The remaining 2010 increase in total deferred tax liabilities was primarily due to the deferred tax liability for the equity component of our convertible debt and an increase in our deferred liability associated with our joint venture investment due to additional tax losses incurred by PDCM.

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As of December 31, 2010, we have state NOL carryforwards of $3.3 million that begin to expire beginning in 2029, and state credit carryforwards of $1.3 million that begin to expire in 2020.

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 or tax credits become utilizable. 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 or utilizable, we have not recorded any valuation allowance as of December 31, 2010. 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 carry-forward period are reduced.

The following table presents a reconciliation of the total amounts of unrecognized tax benefits.

	2010	2009	2008
	(in thousands)		
Balance beginning of year, January 1	$566	$1,271	$888
Additions for tax positions of prior years	253	43	216
Additions for tax positions of current year	274	7	167
Reductions due to settlements	—	(406)	—
Reductions due to lapse of statute of limitations	—	(349)	—
Balance end of year, December 31	$1,093	$566	$1,271

Interest and penalties related to uncertain tax positions are recognized in income tax expense. Accrued interest and penalties related to uncertain tax positions were immaterial for each of the years in the three-year period ended December 31, 2010. The total amount of unrecognized tax benefits that would affect the effective tax rate, if recognized, was $1 million as of December 31, 2010 and $0.6 million as of December 31, 2009. As of December 31, 2010, it is reasonably possible that the unrecognized tax benefit could decrease up to $1 million in the next twelve months due to the conclusion of the current IRS examination and the lapse of an applicable statute of limitation.

The IRS is currently conducting an examination of our 2007 through 2009 tax years and an examination of the 2010 tax year in accordance with the Compliance Assurance Process ("CAP"). The CAP audit employs a real-time review of our books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax returns. The examinations are expected to be completed in 2011. The statute of limitation for most of our state tax jurisdictions is open from 2006 forward.

NOTE 8 - LONG-TERM DEBT

Long-term debt consists of the following:

	As of December 31,	
	2010	2009
	(in thousands)	
Senior notes		

3.25% Convertible senior notes due 2016:		
Principal amount	$115,000	$—
Unamortized discount	(20,252)	—
3.25% Convertible senior notes due 2016, net of discount	94,748	—
12% Senior notes due 2018:		
Principal amount	203,000	203,000
Unamortized discount	(2,053)	(2,343)
12% Senior notes due 2018, net of discount	200,947	200,657
Total senior notes	295,695	200,657
Credit facility	—	80,000
Total long-term debt	$295,695	$280,657

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Senior Notes

3.25% Convertible Senior Notes Due 2016. In November 2010, including the overallotment option that allowed the underwriters to purchase an additional principal amount of $15 million, we issued $115 million of 3.25% convertible senior notes due 2016 in a private placement to qualified institutional buyers pursuant to Rule 144A of the Securities Act of 1933, as amended ("Securities Act"). The convertible notes and the common stock issuable upon conversion of the convertible notes, if any, have not been registered under the Securities Act or any state securities laws, nor are we required to register such convertible notes or common shares. The convertible notes are governed by an indenture dated November 23, 2010, between the Company and the Bank of New York Mellon, as trustee. The maturity for the payment of principal is May 15, 2016. Interest at the rate of 3.25% per year is payable in cash semiannually in arrears on each May 15 and November 15, commencing on May 15, 2011. The convertible notes are senior, unsecured obligations and rank senior in right of payment to our existing and future indebtedness that is expressly subordinated in right of payment to the convertible notes; equal in right of payment to our existing and future unsecured indebtedness that is not so subordinated (including our 12% senior notes due 2018); effectively junior in right of payment to any of our secured indebtedness (including our obligations under our senior secured credit facility) to the extent of the value of the assets securing such indebtedness; and structurally junior to all existing and future indebtedness (including trade payables) incurred by our subsidiaries.

The convertible notes will be convertible prior to November 15, 2015, only upon specified events and during specified periods and, thereafter, at any time, in each case at an initial conversion rate of 23.5849 per $1,000 principal amount of the convertible notes, which is equal to a conversion price of approximately $42.40 per share. The conversion rate is subject to adjustment upon certain events. Upon conversion, the convertible notes may be settled, at our election, in shares of our common stock, cash or a combination of cash and shares of our common stock. We have initially elected a net-settlement method to satisfy our conversion obligation, which allows us to settle the $1,000 principal amount of the convertible notes in cash and to settle the excess conversion value in shares, as well as cash in lieu of fractional shares.

We may not redeem the convertible notes prior to the maturity date of the convertible notes. If we undergo a fundamental change, as defined in the indenture, subject to certain conditions, holders of the convertible notes may require us to repurchase for cash all or part of the convertible notes at a repurchase price equal to 100% of the principal amount of the convertible notes to be repurchased, plus any accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

We allocated the gross proceeds of the convertible notes between the liability and equity components of the debt. The initial $94.3 million liability component was determined based on the fair value of similar debt instruments excluding the conversion feature for similar terms and priced on the same day we issued our convertible notes. The initial $20.7 million equity component represents the debt discount and was calculated as the difference between the fair value of the debt and the gross proceeds of the convertible notes. As of December 31, 2010, the unamortized debt discount will be amortized over the remaining contractual term to maturity of the convertible notes of 5.4 years using an effective interest rate of 7.4%. For 2010, interest expense related to the indebtedness and the amortization of the discount were $0.4 million and $0.5 million, respectively. As of December 31, 2010, notwithstanding the inability to convert, assuming conversion, the value of the convertible notes did not exceed the principal amount.

12% Senior Notes Due 2018. In 2008, we issued $203 million of 12% senior notes due 2018 in a private placement. The notes have not been registered under the Securities Act or any state securities laws, nor are we required to register such notes. The notes are governed by an indenture dated February 8, 2008, between the Company and the Bank of New York, as trustee, as supplemented by the first supplement indenture dated said date. The maturity for the payment of principal is February 15, 2018. Interest at the rate of 12% per year is payable in cash semiannually in arrears on each February 15 and August 15. The senior notes were issued at a discount, 98.572% of the principal amount. 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 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: (a) incur additional debt, (b) make certain investments or pay dividends or distributions on our capital stock or purchase or redeem or retire capital stock, (c) sell assets, including capital stock of our restricted subsidiaries, (d) pay dividends or other payments by restricted subsidiaries, (e) create liens that secure debt, (f) enter into transactions with affiliates, and (g) merge or consolidate with another company. Additionally, we are subject to two incurrence covenants: 1) earnings before interest, taxes, DD&A expense and capital expenditures ("EBITDAX") of at least two times interest expense and 2) total debt of less than 4.0 times EBITDAX. We were in compliance with all covenants as of December 31, 2010, and expect to remain in compliance throughout the next year.

The notes are not initially guaranteed by any of our subsidiaries. However, subsidiaries may be obligated to guarantee the notes if a subsidiary becomes 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. As of December 31, 2010, none of our subsidiaries were obligated as guarantors of our senior notes.

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. As of the date of issuance of these financial statements, this provision expired without any redemptions having occurred.

The indenture provides 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.

Bank Credit Facilities

Corporate Credit Facility. Prior to November 5, 2010, we operated under a secured credit facility dated as of November 4, 2005, as amended last on December 18, 2009, with an aggregate revolving commitment of $305 million and was due to expire on May 22, 2012. This credit facility was replaced on November 5, 2010, with a new credit facility. Our senior secured credit facility dated as of November 5, 2010, amended last on December 22, 2010, has an initial aggregate revolving commitment or borrowing base of $321.2 million. The maximum allowable facility amount is $600 million. The credit facility is with certain commercial lending institutions and is available for working capital requirements, capital expenditures, acquisitions, general corporate purposes, and to support letters of credit.

Our credit facility borrowing base is subject to size redetermination semiannually based on a quantification of our reserves at December 31 and June 30 and is also subject to a redetermination upon the occurrence of certain events. The borrowing base of the credit facility will be the loan value assigned to the proved reserves attributable to our and our subsidiaries’ natural gas and crude oil interests. The credit facility is secured by a pledge of the stock of certain of our subsidiaries, mortgages of certain producing natural gas and crude oil properties and substantially all of our and such subsidiaries’ other assets. Neither PDCM nor the various limited partnerships for which we have sponsored and continue to serve as the managing general partner are guarantors of the credit facility.

Our outstanding principal amount accrues interest at a varying interest rate that fluctuates with an alternate base rate (equal to the greater of JPMorgan Chase Bank, N.A.'s prime rate, the federal funds rate plus a premium and 1-month LIBOR plus a premium), or at our election, a rate equal to the rate for dollar deposits in the London interbank market for certain time periods. Additionally, commitment fees, interest margin and other bank fees, charged as a component of interest, vary with our utilization of the facility. No principal payments are required until the credit agreement expires on November 5, 2015, or in the event that the borrowing base would fall below the outstanding balance.

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, and (g) engage in hedging activities unless certain requirements are satisfied. 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. Further, we are required to comply with certain financial tests and maintain certain financial ratios on a quarterly basis. The financial tests and ratios include requirements to: (a) maintain a minimum current ratio, as defined per credit facility, of 1.00 to 1.00 and (b) not exceed a maximum leverage ratio of 4.25 to 1.00 through December 31, 2011, and 4.00 to 1.00 thereafter.

We have outstanding an $18.7 million irrevocable standby letter of credit in favor of a third party transportation service provider to secure the construction of certain additions and/or replacements to its facilities to provide firm transportation of the natural gas produced by us and others for whom we market their production in the West Virginia and Southwestern Pennsylvania areas. The letter of credit reduces the amount of available funds under our credit facility by an equal amount. We pay a fronting fee of 0.125% per annum and an additional quarterly maintenance fee equivalent to the spread over Eurodollar loans (2.0% per annum as of December 31, 2010) for the period the letter of credit remains outstanding. The letter of credit expires on May 22, 2012.

As of December 31, 2010, we had no outstanding draws on our credit facility compared to $80 million as of December 31, 2009. We pay a fee of 0.5% per annum on the unutilized commitment on our available funds under our credit facility. As of December 31, 2010, the available funds under our credit facility were $302.5 million. The weighted average borrowing rate on our credit facility, exclusive of the letter of credit, was 4.9% and 4.1% in 2010 and 2009, respectively. We were in compliance with all covenants at December 31, 2010, and expect to remain in compliance throughout the next year.

PDCM Credit Facility. PDCM has a credit facility dated as of April 30, 2010, with an initial borrowing base of $10 million. The maximum allowable facility amount is $100 million. PDCM is required to pay a commitment fee of 0.5% per annum on the unutilized portion of the activated credit facility. Based upon PDCM's discretion, interest accrues at either an alternative base rate ("ABR") or an adjusted LIBOR. The ABR is the greater of BNP Paribas' prime rate, the federal funds effective rate plus 0.5% or the adjusted LIBOR for a three month interest period plus 1%. ABR and adjusted LIBOR borrowings are assessed an additional margin based upon the outstanding balance as a percentage of the available balance. ABR borrowings are assessed an additional margin of 1.5% to 2.25%. Adjusted LIBOR borrowings are assessed an additional margin spread of 2.5% to 3.25%. No principal payments are required until the credit agreement expires on April 30, 2014, or in the event that the borrowing base would fall below the outstanding balance. The credit facility is subject to and secured by

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PDCM's properties, with no recourse to us. The credit facility borrowing base is subject to size redetermination semiannually based upon a quantification of PDCM's reserves at December 31 and June 30; further, either PDCM or the lenders may request a redetermination upon the occurrence of certain events. Pursuant to the interests of the joint venture, the credit facility will be utilized by PDCM for the exploration and development of its Appalachian assets.

The credit facility contains covenants customary for agreements of this type, including, but not limited to, limitations on PDCM's ability to: (a) incur additional indebtedness and guarantees, (b) create liens and other encumbrances on their 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, and (g) engage in hedging activities unless certain requirements are satisfied. The credit facility also requires PDCM to execute and deliver specified mortgages and other evidences of security and to deliver specified opinions of counsel and other evidences of title. Further, PDCM is required to comply with certain financial tests and maintain certain financial ratios, as defined by the credit facility, on a quarterly basis. The financial tests and ratios include requirements to: (a) maintain a minimum current ratio of 1.0 to 1.0, (b) not to exceed a debt to EBITDAX ratio of 3.5 to 1.0 and (c) maintain a minimum interest coverage ratio of 2.5 to 1.0.

As of December 31, 2010, there were no amounts outstanding related to this credit facility and PDCM was in compliance with all covenants.

NOTE 9 - ASSET RETIREMENT OBLIGATIONS

The following table presents the changes in carrying amounts of the asset retirement obligations associated with our working interest in natural gas and crude oil properties.

	2010	2009
	(in thousands)	
Balance beginning of year, January 1	$29,564	$23,086
Deconsolidation of PDCM and change in ownership interest	(6,564)	—
Obligations incurred with development activites and assumed with acquisitions	4,549	883
Accretion expense	1,423	1,368
Obligations discharged with disposal of properties and asset retirements	(925)	(52)
Revisions in estimated cash flows	—	4,279
Balance end of year, December 31 (1)	28,047	29,564
Less current portion	(250)	(250)
Long-term portion	$27,797	$29,314

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(1) Includes $0.2 million and $1 million as of December 31, 2010 and 2009, respectively, related to assets held for sale.

NOTE 10 - EMPLOYEE BENEFIT PLANS

We sponsor a qualified retirement plan covering substantially all of our employees. The plan consists of both a traditional and a Roth 401(k) component as well as a profit sharing component. The 401(k) components enable 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 plan in 2010, 2009 and 2008, was $2.6 million, $1.7 million and $1.9 million, respectively.

We provide a supplemental retirement benefit of deferred compensation under terms of the various employment agreements with certain executive officers. During 2010, 2009 and 2008, we charged $0.2 million, $0.3 million and $0.2 million, respectively, related to this plan to general and administrative expenses. As of December 31, 2010 and 2009, the liability related to this benefit was $2.3 million and $2.4 million, respectively, which was included in other liabilities on the balance sheets, with the exception of $0.3 million included in other accrued expenses as of December 31, 2010 and 2009.

We offer a supplemental health care benefit covering certain former executive officers and their spouses in accordance with each officer's employment agreement. Expenses incurred during 2010, 2009 and 2008 related to this plan were immaterial. As of December 31, 2010 and 2009, included in other liabilities on the balance sheets was a related liability of $0.6 million and $0.5 million, respectively.

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 balance sheets 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, 2010 and 2009, the liability related to this plan was $0.1 million and $0.2 million, respectively, which was included in other liabilities on the balance sheets.

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NOTE 11 - COMMITMENTS AND CONTINGENCIES

Merger Agreements. In November 2010, we entered into separate merger agreements with each of PDC 2005-A Limited Partnership, PDC 2005-B Limited Partnership and the Rockies Region Private Limited Partnership ("2005 Partnerships"). Pursuant to each merger agreement, if the merger is approved by the holders of a majority of the limited partnership units held by limited partners of that partnership not owned by us (the "investor partners"), as well as the satisfaction of other customary closing conditions, then the applicable partnership will merge with and into us. If all three partnerships are acquired, we will pay an aggregate of approximately $43.3 million for the limited partnership units of the investor partners of these partnerships. Definitive proxy statements for each of the partnerships requesting approval from the applicable investor partners for, among other things, the merger agreements were mailed to investors on February 7, 2011. The special meetings whereby investor partners will have an opportunity to vote and approve the applicable merger agreement are currently scheduled for March 25, 2011, for each of the partnerships. Funding for these acquisitions is expected to be provided through the utilization of our corporate credit facility.

Drilling Rig Contract. In order to secure the services of a drilling rig, PDCM entered into a commitment with a drilling contractor for the services of a drilling rig. The commitment expires in October 2012. As of December 31, 2010, our proportionate share of PDCM's related maximum commitment was $6.6 million,.

Firm Transportation Agreements. We have entered into contracts that provide firm transportation, sales and processing charges on pipeline systems through which we transport or sell our natural gas and the natural gas of working interest owners, PDCM, our affiliated partnerships and other third parties. These contracts require us to pay these transportation and processing charges whether the required volumes are delivered or not. Satisfaction of the volumes requirements include volumes produced by us, volumes purchased from third parties, volumes produced by our joint venture and affiliated partnerships; however, all shortfalls are borne by us. As of December 31, 2010, we have a liability in the amount of $3.1 million included in other liabilities on the balance sheet related to an agreement in our Piceance Basin. We are currently working with the third party to renegotiate the terms and timing of our volume requirements under this agreement. If we are not able to renegotiate this agreement or meet all expected future volumes, an additional liability may result.

The following table presents gross volume information related to our long-term firm sales, processing and transportation agreements for pipeline capacity. These agreements require a demand charge whether volumes are delivered or not. We record in our financial statements only our share of costs based upon our working and net revenue interest in the wells. If the volumes below are not met, we will bear all costs related to the volume shortfall.

	Year Ending December 31,						
Area	2011	2012	2013	2014	2015 Through Expiration	Total	Expiration Date
Volume (MMcf)							
Piceance	32,288	32,786	30,458	25,116	71,610	192,258	May 31, 2021
Appalachian Basin (1)	4,054	9,551	16,287	16,287	120,633	166,812	August 31, 2022
NECO	3,650	1,825	1,825	1,825	3,650	12,775	December 31, 2016
Total	39,992	44,162	48,570	43,228	195,893	371,845	
	$19,724	$21,667	$23,987	$21,183	$92,400	$178,961	

Dollar commitment
(in thousands)

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(1) Includes a precedent agreement that becomes effective when the planned pipeline is placed in service, currently estimated to be 2012 and represents 10,629 MMcf of the total MMcf presented for each of the years ending December 31, 2013 and 2014, and 81,536 MMcf thereafter. This agreement will be null and void if the pipeline is not completed. In August 2009, we issued a letter of credit related to this agreement, see Note 8.

Litigation. The Company is involved in various legal proceedings that it considers normal to its business. The Company reviews the status of these proceedings on an ongoing basis and, from time to time, may settle or otherwise resolve these matters on terms and conditions that management believes are in the best interests of the Company. There are no assurances that settlements can be reached on acceptable terms or that adverse judgments, if any, in the remaining litigation will not exceed the amounts reserved.

Royalty Owner Class Action

Gobel et al v. Petroleum Development Corporation, Case No. 09-C-40 in U. S. District Court, Northern District of West Virginia, filed on January 27, 2009

David W. Gobel, individually and allegedly as representative of all royalty owners in the Company's West Virginia oil and gas wells, filed a lawsuit against the Company alleging that we failed to properly pay royalties (the "Gobel lawsuit"). The allegations state that the Company improperly deducted certain charges and costs before applying the royalty percentage. Punitive damages are requested in addition to breach of contract, tort and fraud allegations. On August 31, 2010, the federal judge issued an order remanding the case to state court. On October 27, 2010, the state court set a trial date of April 2012. The Company and the plaintiff have been engaged in settlement discussions. In 2010, the Company recorded a charge to natural gas, NGL and crude oil sales in the statement of operations of $3.3 million. As of December 31, 2010, the Company has a total accrual of $6.2 million related to this suit. Given the inherent uncertainty in actions of this nature, the Company is unable to predict the ultimate outcome of this case at this time; however, it could result in a loss in excess of the amount accrued.

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

Environmental. Due to the nature of the natural gas and oil industry, we are exposed to environmental risks. We have various policies and procedures to avoid environmental contamination and mitigate the risks from environmental contamination. We conduct periodic reviews to identify changes in our environmental risk profile. Liabilities are accrued when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. As of December 31, 2010, we have accrued environmental liabilities in the amount of $1.7 million included in other accrued liabilities on the balance sheet. We are not aware of any environmental claims existing as of December 31, 2010, which have not been provided for or would otherwise have a material impact on our financial statements. However, there can be no assurance that current regulatory requirements will not change or unknown past non-compliance with environmental laws will not be discovered on our properties.

In July 2008, the Company self-reported to the Colorado Department of Public Health and Environment (the "CDPHE") certain non-compliance with air laws at a compressor station in the Piceance Basin. The CDPHE subsequently initiated a review and inspection of air compliance at this station. In November and December 2009, the Company received related compliance advisories for alleged non-compliance. On May 27, 2010, we entered into a settlement agreement providing for a civil penalty of $163,000, which was accrued in periods prior to settlement and paid in the second quarter of 2010.

In December 2008, we received a Notice of Violation/Cease and Desist Order (the "Notice") from the CDPHE, related to the stormwater permit for the Garden Gulch Road. The Company manages this private road for Garden Gulch LLC. The Company is one of eight users of this road, all of which are natural gas and oil companies operating in the Piceance region of Colorado. Operating expenses, including this fine, if any, are allocated among the users of the road based upon their respective usage. The Notice alleges a deficient and/or incomplete stormwater management plan, failure to implement best management practices and failure to conduct required permit inspections. The Notice requires corrective action and states that the recipient shall cease and desist such alleged violations. The Notice states that a violation could result in civil penalties up to $10,000 per day. In 2009, the Company submitted responses and entered into negotiations with the CDPHE regarding this notice. In November 2010, the Company entered into a settlement for a total of $160,920, a portion of which was provided directly to a local municipality for a supplemental environmental project. The $160,920 was paid in January 2011.

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 from production), if repurchase is requested by investors, subject to our financial ability to do so. As of December 31, 2010, the maximum annual repurchase obligation for 2011, based upon the minimum price described above, was approximately $7.1 million. We believe we have adequate liquidity to meet this obligation. During 2010, 2009 and 2008, we paid $0.6 million, $1.7 million and $1.8 million, respectively, under this provision for the repurchase of partnership units.

Lease Agreements. We entered into operating leases principally for the leasing of natural gas compressors, office space in Denver and Bridgeport, and general office equipment. The following table presents the minimum future lease payments under the non-cancelable operating leases as of December 31, 2010.

	Year Ending December 31,						
	2011	2012	2013	2014	2,015	Thereafter	Total
	(in thousands)						
Minimum Lease Payments	$2,226	$1,900	$1,697	$1,508	$1,469	$13	$8,813

Operating lease expense for the years ended December 31, 2010, 2009 and 2008, was $4.9 million, $4.3 million and $2.6 million, respectively.

Employment Agreements with Executive Officers. We have employment agreements with our Chief Executive Officer, Chief Financial 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 severance benefits.

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If within two years following a change of control of the Company ("change in control period") either the Company terminates the executive officer without cause or the executive officer terminates employment for good reason, then the severance benefits owed equals two or three times, specific to the executive officer, the sum of the executive's highest annual base salary during the previous two years of employment immediately preceding the termination date and the executive's highest annual bonus paid or payable during the same two-year period. For one executive, in this calculation, the target bonus will be used as the minimum value for the first two years of employment. Where the Company terminates the executive officer without cause or the executive officer terminates employment for good reason outside of the change in control period, the severance benefits also range from two times to three times the benefits noted above. For this purpose, a change of control and good reason correspond to the respective definitions of change of control and good reason under Section 409A of the Internal Revenue Code of 1986 (IRC) and the supporting treasury regulations, with some differences. Under any of the above circumstances, the executive officer is also entitled under his employment agreement to (i) vesting of any unvested equity compensation (excluding all long-term performance shares), (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 the federal COBRA health continuation coverage period 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 entitled to receive under our qualified retirement 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 a partial year bonus; incentive, deferred, retirement or other compensation; and to provide any other benefits, which have been earned or become payable as of the termination date.

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 and bonus, provided, however, that with respect to the bonus, for certain executive officers, there will be no proration of the bonus if such executive leaves prior to the last day of the year and, with respect to the remaining executive officers, there will be no proration of the bonus in the event such executive officer leaves prior to March 31 in the year of his termination, (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, (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.

In the event of death or disability, the executive is entitled to receive certain benefits. For this purpose, the definition of "disability" corresponds to the definition under IRC 409A and the supporting treasury regulations. The benefits will (i) in the case of death be equal to the base salary that would otherwise have been paid for a six-month period following the termination date and (ii) in the case of disability be up to thirteen weeks of ongoing base salary plus a lump sum equal to six months of base salary.

Partnership Casualty Losses. As Managing General Partner of 29 partnerships, we have liability for 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.

NOTE 12 - COMMON STOCK

Sale of Equity Securities

The following offerings were made pursuant to an effective shelf registration statement on Form S-3 filed with the SEC on November 26, 2008, and declared effective on January 30, 2009.

- In November 2010, we sold 4,140,000 shares of our common stock in an underwritten public offering at a price of $32.00 per share. The net proceeds of $125.5 million are being used, together with other proceeds, to fund an acquisition of additional assets in the Wolfberry Trend in the Permian Basin of West Texas, which closed in November 2010; our acquisition of the 2004 partnerships, which closed in December 2010 for $34.8 million, and will be used for the anticipated acquisition of the 2005 partnerships and other acquisitions and for general corporate purposes. Pending such uses, we applied the net proceeds from this offering and other proceeds to temporarily repay the entire outstanding amount under our credit facility, with the remaining balance being deposited in an interest bearing account and held as cash and cash equivalents until utilized as contemplated above.
- In August 2009, we sold 4,312,500 shares of our common stock in an underwritten public offering at a price of $12.00 per share. We used the net proceeds of $48.5 million to pay down our credit facility and for general corporate purposes.

Stock-Based Compensation Plans

2010 Long-Term Equity Compensation Plan. In June 2010, our shareholders approved a long-term equity compensation plan for our employees and non-employee directors (the "2010 Plan"). In accordance with the 2010 Plan, up to 1,400,000 new shares of our common stock are authorized for issuance. Shares issued may be either authorized but unissued shares, treasury shares or any combination of these shares. Additionally, the 2010 Plan permits the reuse or reissuance of shares of common stock which were canceled, expired, forfeited or, in the case of stock appreciation rights ("SARs"), paid out in the form of cash. Awards may be issued to our employees in the form of stock options, SARs, restricted stock, restricted stock units ("RSUs"), performance shares and performance units and to our non-employee directors in the form of non-qualified stock options, SARs, restricted stock and RSUs. Awards may vest over periods set at the discretion of the

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Compensation Committee of our Board of Directors (the "Compensation Committee") with certain minimum vesting periods. With regard to options and SARs, awards have a maximum exercisable period of ten years. In no event may an award be granted under the 2010 Plan on or after April 1, 2020. As of December 31, 2010, 1,181,288 shares remain available for issuance pursuant to the 2010 Plan.

Other Long-Term Equity Compensation Plan. As approved by the shareholders in June 2004, we maintain a long-term equity compensation plan for our officers and certain key employees (the "2004 Plan"). Awards pursuant to the plan vest over periods set at the discretion of the Compensation Committee and, with regard to options, have a maximum exercisable period of ten years. We also maintain a restricted stock plan for our non-employee directors approved by the shareholders in June 2005 (the "2005 Plan"). As of December 31, 2010, shares remaining available for issuance pursuant to these plans were de minimis and we have no intent to issue such shares. As of December 31, 2010, there were no awards outstanding pursuant to the 2005 Plan. All outstanding and non-vested awards pursuant to the 2004 Plan will continue to be outstanding and vest pursuant to their original terms on or before April 19, 2020.

The following table presents summary data related to our outstanding stock-based compensation plans.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Total stock-based compensation	$5,314	$5,935	$6,702
Income tax benefit	(2,019)	(2,277)	(2,557)
Net income (loss) impact	$3,295	$3,658	$4,145

Stock Option Awards

We have granted stock options pursuant to various stock compensation plans. Outstanding options expire ten years from the date of grant and become exercisable ratably over a four year period. We have not issued any new stock options awards since 2006. As of December 31, 2010, all compensation cost related to stock options has been fully recognized in our statement of operations.

The following table presents the changes in our stock option awards for the year ended December 31, 2010.

	Number of Shares Underlying Options	Weighted Average Exercise Price Per Share	Weighted Average Remaining Contractual Term (years)
Outstanding at December 31, 2009	10,306	$41.90	6
Outstanding at December 31, 2010	10,306	41.90	5
Vested and expected to vest at December 31, 2010	10,306	41.90	5
Exercisable at December 31, 2010	10,306	41.90	5

As of/Year Ended December 31,

	2010	2009	2008
	(in thousands, except market price)		
Total intrinsic value of options exercised	$—	$—	$659
Total intrinsic value of options outstanding	18	—	—
Total intrinsic value of options exercisable	18	—	—
Market price per common share as of December 31	42.25	18.21	24.07

SARs

In April 2010, our Compensation Committee granted SARs to our executive officers. The SARs will vest over a three-year period and may be exercised at any point after vesting through April 2020. Pursuant to the terms of the awards, upon exercise, the executives will receive in shares of common stock the excess of the market price of the award on the date of exercise over the market price of the award on the date of issuance.

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The fair value of each SAR award was estimated on the date of grant using a Black-Scholes pricing model using the assumptions presented in the table below. The expected life of the award was estimated using historical stock option exercise behavior data. The risk-free interest rate was based on the U.S. Treasury yields approximating the expected life of the award in effect at the time of grant. Expected volatilities were based on our historical volatility. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

	Year Ended December 31, 2010	
Expected term of the award	5 years	
Risk-free interest rate	2.5	%
Volatility	62.0	%
Weighted average grant date fair value per share	$13.26	

The following table presents the changes in our SARs for the year ended December 31, 2010.

	Number of Shares Underlying SARs	Grant Date Market Price Per Share	Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands)
Outstanding at December 31, 2009	—	$—	—	$—
Awarded	57,282	24.44	9.3	—
Outstanding at December 31, 2010	57,282	24.44	9.3	1,020
Vested and expected to vest at December 31, 2010	51,554	24.44	9.3	918
Exercisable at December 31, 2010	—	—	—	—

The total compensation cost related to SARs granted and not yet recognized in our statement of operations as of December 31, 2010, was $0.5 million. The cost is expected to be recognized over a weighted average period of 2.3 years.

Restricted Stock Awards

Time-Based Awards. The fair value of the time-based awards is amortized ratably over the requisite service period, generally over three or four years, and, in connection with a one-time grant to executive officers in March 2008, five years . Time-based awards for non-employee directors prior to 2010 generally vested on July 1 of the year following the date of the grant. Non-employee director awards pursuant to the 2010 Plan vest ratably over three years.

The following table presents the changes in non-vested time-based awards for the year ended December 31, 2010.

	Shares	Weighted Average Grant-Date Fair Value
Non-vested at December 31, 2009	305,328	$27.55

Granted	367,641	25.04
Vested	(125,646)	28.65
Forfeited	(21,608)	27.60
Non-vested at December 31, 2010	525,715	25.53

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	As of/Year Ended December 31,		
	2010	2009	2008
	(in thousands, except per share data)		
Total intrinsic value of time-based awards vested	$3,219	$1,731	$6,710
Total intrinsic value of time-based awards non-vested	22,211	5,560	5,249
Market price per common share as of December 31	42.25	18.21	24.07
Weighted average grant date fair value per share	25.04	14.02	57.64

The total compensation cost related to non-vested time-based awards expected to vest and not yet recognized in our statements of operations as of December 31, 2010, was $9.5 million. This cost is expected to be recognized over a weighted average period of 2.4 years.

Market-Based Awards. The fair value of the market-based awards is amortized ratably over the requisite service period, primarily three years. Generally, the market-based shares vest if the participant is continuously employed throughout the performance period and certain per share price thresholds are attained as of the last day of each performance period, with a maximum vesting period of five years. 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 per market-based share, including shares modified in 2008 pursuant to agreements with our former president and our former chief executive officer, was computed using the Monte Carlo pricing model using the weighted average assumptions presented in the table below.

	Year Ended December 31,	
	2009	2008
Expected term of award	3 years	3 years
Risk-free interest rate	2.0 %	2.7 %
Volatility	59.0 %	45.6 %
Weighted average grant date fair value per share	$6.47	$43.61

For 2009, expected volatility was based on a blend of our historical and implied volatility and, for 2008, was based on our historical volatility. The expected lives of the awards were based on the requisite service period. The risk-free interest rate was based on the U.S. Treasury yields in effect at the time of grant or modification and extrapolated to approximate the life of the award. We do not expect to pay dividends, nor do we expect to declare dividends in the foreseeable future.

There were 79,550 shares of non-vested market-based awards, with a weighted average grant-date fair value of $32.52 per share, outstanding as of December 31, 2010 and 2009. There was no activity related to these shares during 2010. The total compensation cost related to non-vested market-based awards expected to vest and not yet recognized in our statement of operations as of December 31, 2010, was immaterial. This cost is expected to be recognized over a weighted average period of one year.

Treasury Share Purchases

Treasury shares purchased pursuant to our non-employee director deferred compensation plan are purchased in the open market at fair value and held in a rabbi trust.

Pursuant to our stock-based compensation plans, we purchase shares from employees for their payment of tax liabilities related to the vesting of securities. Shares are purchased at fair market value based on the closing price on the date of purchase and subsequently retired.

In 2006, our Board approved a 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 were made in 2007 and 2008 in the open market or in private transactions, at times and in amounts that we deemed appropriate. Total shares purchased pursuant to the purchase program were 76,283 common shares at a cost of $5 million ($65.73 average price paid per share), including 68,943 shares from our executive officers at a cost of $4.6 million ($67.22 price paid per share). The authorization to purchase the remaining 1,400,826 shares effectively expired on April 30, 2008. All shares purchased in accordance with the program were subsequently retired.

Pursuant to our senior notes indenture executed in February 2008, any future treasury purchases are restricted, see Note 8.

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Shareholders' Rights Agreement

In 2007, we entered into a rights agreement. The rights agreement is designed to improve the ability of our Board 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.

Preferred stock

We are authorized, pursuant to shareholder approval in 2008, to issue 50,000,000 shares of Company preferred stock, par value $0.01, which may be issued in one or more series, with such rights, preferences, privileges and restrictions as shall be fixed by our Board from time to time. As of December 31, 2010, no preferred shares had been issued.

NOTE 13 - ASSETS HELD FOR SALE, DIVESTITURE AND DISCONTINUED OPERATIONS

Selected financial information related to assets held for sale, divested and discontinued operations. The tables below set forth selected financial and operational information related to net assets divested, net assets related to discontinued operations and operating results related to discontinued operations. Net assets held for sale represents the assets that were or are expected to be sold net of liabilities that were or are expected to be assumed by the purchaser. Net assets related to discontinued operations presents those assets that were or are expected to be sold less liabilities that were or are expected to be assumed by the purchaser, as well as all other related assets and liabilities, consisting of accounts receivable and production tax liability, which were not sold. While the reclassification of revenues and expenses related to discontinued operations for prior periods had no impact upon previously reported net earnings, the statement of operations and operational tables present the revenues, expenses and production volumes that were reclassified from the specified statement of operations line items to discontinued operations.

The following table presents statement of operations data related to our discontinued operations.

	Year Ended December 31,		
Statement of Operations - Discontinued Operations	2010	2009	2008
	(dollars in thousands)		
Revenues			
Natural gas, NGL and crude oil sales	$6,515	$7,851	$17,010
Sales from natural gas marketing	3,328	5,040	11,248
Natural gas and crude oil well drilling	—	193	7,615
Well operations, pipeline income and other	549	951	986
Total revenues	10,392	14,035	36,859
Costs, expenses and other			

Production costs	2,358	2,643	4,155
Cost of natural gas marketing	3,265	4,916	11,161
Cost of natural gas and oil well drilling	—	—	1,068
Exploration expense	25	3,784	497
Impairment of proved natural gas and oil properties	4,666	—	5,246
Depreciation, depletion and amortization	1,819	4,249	3,197
Total costs, expenses and other	12,133	15,592	25,324
Income (loss) from discontinued operations	(1,741)	(1,557)	11,535
Provision (benefit) for income taxes	(754)	(582)	4,122
Income (loss) from discontinued operations, net of tax	$(987)	$(975)	$7,413
Operational Data			
Production			
Natural gas (MMcf)	801.8	1,446.4	1,658.7
Crude oil (MBbls)	42.5	47.5	24.7
Natural gas equivalent (MMcfe)	1,057.0	1,731.6	1,806.6

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The following table presents balance sheet data related to assets held for sale.

	As of December 31,			
	2010		2009	
Balance Sheet	Net Assets Held for Sale (1)	Net Assets Related to Discontinued Operations	Net Assets Held for Sale (1)	Net Assets Related to Discontinued Operations
	(in thousands)			
Assets				
Current assets				
Accounts receivable, net	$—	$347	$—	$1,499
Total current assets	—	347	—	1,499
Properties and equipment, net	16,578	16,578	65,996	65,996
Accumulated DD&A	(11,387)	(11,387)	(31,461)	(31,461)
Total assets	$5,191	$5,538	$34,535	$36,034
Liabilities				
Current liabilities				
Production tax liability	$—	$—	$—	$37
Total current liabilities	—	—	—	37
Asset retirement obligation	199	199	957	957
Total liabilities	$199	$199	$957	$994
Net Assets	$4,992	$5,339	$33,578	$35,040

(1) See Note 9 for additional information regarding the asset retirement obligation related to assets held for sale and divested in July 2010.

Assets Held for Sale

North Dakota. During the fourth quarter of 2010, we developed a plan to divest and began marketing for sale our North Dakota assets. The assets include producing wells, undeveloped leaseholds and related facilities primarily located in Burke County. The plan received board approval and the sale is expected to occur within one year of approval. In December 2010, we executed a letter of intent with an unrelated third party, which provides for the sale of 100% of our North Dakota assets. On February 7, 2011, we executed a purchase and sale agreement with the same unrelated party and we expect the transaction to close early March 2011. Following the sale to the unrelated party, we will not have significant continuing involvement in the operations of or cash flows from these assets; accordingly, the North Dakota assets were reclassified as held for sale and the results of operations related to the those assets have been separately reported as discontinued operations in the consolidated financial statements for all periods presented.

Michigan. On July 30, 2010, we divested our Michigan asset group and related liabilities for net cash proceeds of $22 million and realized a loss on sale of $4.7 million in the form of an impairment charge recorded during the year ended 2010 (see Note 2 regarding the impairment charge). We do not have significant continuing involvement in the operations of or cash flows from this asset group. Accordingly, the Michigan assets were reclassified as held for sale and the results of operations related to the those assets have been separately reported as discontinued operations in the consolidated financial statements for all periods presented.

Natural Gas and Crude Oil Well Drilling Activities

We offered our last sponsored drilling partnership in October 2007. In January 2008, we first announced that we had no plans to sponsor a new drilling partnership in 2008 and this decision was upheld again in 2009. As of June 30, 2009, all remaining contractual drilling and completion obligations were completed for all partnerships. The unused advance for future drilling contracts of $1.7 million as of December 31, 2008, was fully utilized as of June 30, 2009, with $0.2 million recognized in revenue and $0.3 million refunded to the partnerships.

As all partnership well drilling and completion activities have been completed and we currently do not have any plans in the foreseeable future to sponsor a drilling partnership, we believe it was appropriate to treat our natural gas and crude oil well drilling activities as discontinued operation for all periods presented. Prior period financial statements have been restated to present the activities of our natural gas and crude oil well drilling operations as discontinued operations.

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NOTE 14 - ACQUISITIONS

The following table presents the adjusted purchase price and the preliminary allocations thereof, based on our estimates of fair value, for the acquisition of natural gas and crude oil properties in the Permian Basin and the 2004 partnerships.

	Permian Acquisitions		2004 Partnerships
	November 2010	July 2010	December 2010
	(in thousands)		
Cash consideration paid to seller	$39,364	$74,650	$34,768
Payable to seller	—	259	—
Total consideration for net assets	$39,364	$74,909	$34,768
Recognized amounts of identifiable assets acquired and liabilities assumed:			
Proved natural gas and oil properties	$18,063	$27,529	$32,730
Unproved natural gas and oil properties	21,507	50,140	—
Fair value of derivative instruments	—	—	1,682
Other assets	—	—	1,714
Asset retirement obligation	(177)	(2,174)	(912)
Environmental liability	(29)	(586)	(126)
Other liabilities	—	—	(320)
Total identifiable net assets	$39,364	$74,909	$34,768

Pro Forma Information. The results of operations for the above acquisitions have been included in our consolidated financial statements from the date of acquisition. The pro forma effect of their inclusion in our consolidated statement of operations of the results of operations of these assets as if the acquisitions had occurred as of January 1, 2009, are not presented as the pro forma results would not be materially different from the information presented in the accompanying statements of operations.

Permian Basin. In July 2010, we acquired various producing assets located in the Wolfberry oil trend in the Permian Basin in West Texas. In conjunction with the divestiture of our Michigan asset group we entered into a like-kind exchange agreement, in accordance with Internal Revenue Code Section 1031 ("IRC 1031"), with a qualified intermediary. The Wolfberry assets were identified as our replacement property in accordance with IRC 1031. Sales proceeds in the amount of $19.3 million from the Michigan divestiture were transferred directly to the qualified intermediary and used, along with $55.7 million from our credit facility, to fund our Wolfberry acquisition. The sale of our Michigan assets resulted in a gain for income tax purposes of $19.2 million, which then resulted in a tax liability of $7.3 million. With the favorable deferral aspects of IRC 1031, we were able to defer $6.5 million of this tax liability.

In November 2010, we acquired for $39.4 million in cash a second position in the Wolfberry oil trend including 100% of the interest in producing assets and undeveloped acreage. The assets included seven producing wells that are located on a primarily contiguous 5,760 net acre block. We believe that these Permian acquisitions will support our strategic goal of diversifying our commodity mix to include a larger percentage of liquids.

2004 Partnerships. In December 2010, we acquired the remaining working interest in four of our affiliated partnerships: PDC 2004-A Limited Partnership, PDC 2004-B Limited Partnership, PDC 2004-C Limited Partnership and PDC 2004-D Limited Partnership. We purchased these partnerships for an aggregate amount of $36.5 million, which includes $1.7 million paid to our unaffiliated partners for operating results between the valuation date and date of closing. These purchases included the remaining working interests in a total of 122 gross, 88.6 net, wells located in our Wattenberg and Grand Valley Fields. The acquisitions allow us the opportunity, assuming favorable capital and commodity markets, to accelerate the pace of refracturing the wells acquired, thus allowing us to optimize revenue opportunities.

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NOTE 15 - NONCONTROLLING INTEREST IN SUBSIDIARIES

PDC Mountaineer, LLC

In October 2009, we entered into a joint venture arrangement to form PDCM. At that time, the joint venture was determined to be a variable interest entity due to the disproportionate voting rights compared to our ownership interest; accordingly, we consolidated 100% of the joint venture as we were the primary beneficiary as of and for the period ended December 31, 2009. As of January 1, 2010, pursuant to the adoption of new accounting changes related to variable interest entities (see Note 2), the joint venture was deconsolidated from 100% and proportionately consolidated at 67.4%, representing only our ownership interest.

The assets we contributed consist of (i) approximately 115,000 net acres in the Appalachian Basin, of which approximately 55,000 acres are in the Marcellus fairway, (ii) 12 MMcf per day of existing production from primarily the shallow Devonian sands and (iii) total proved reserves of 113 Bcfe, also from the shallow Devonian sands. With the exception of our capital contribution, we have not entered into any arrangement that would require us to provide financial support to the joint venture. Further, we are not liable for any debts, obligations and liabilities of the joint venture and its creditors have no recourse against our general credit in the event of default. None of our affiliated partnerships' wells were included in the joint venture.

The following table presents the impact on our balance sheet resulting from the deconsolidation of PDCM on January 1, 2010. The changes below are non-cash items with the exception of the changes in cash and cash equivalents, which are reflected in the statement of cash flows.

As of January 1, 2010
(decrease/(increase), in thousands)

Assets		Liabilities and Equity	
Current assets		Current liabilities	
Cash and and cash equivalents	$3,074	Accounts payable	$813
Accounts receivable, net	1,335	Production tax liability	17
Accounts receivable affiliates	(2,399)	Fair value of derivatives	434
Fair value of derivatives	2	Funds held for distribution	322
Prepaid expenses and other current assets	131	Other accrued expenses	—
Total current assets	2,143	Total current liabilities	1,586
Properties and equipment, net	51,765	Fair value of derivatives	83
Fair value of derivatives	70	Asset retirement obligation	4,815
Other assets	419	Other liabilities	591
Total assets	$54,397	Total liabilities	7,075
		Shareholders' equity	—
		Noncontrolling interest	47,322
		Total equity	47,322
		Total liabilities and equity	$54,397

WWWV, LLC

In 2007, we contributed $0.8 million for a 50% interest in WWWV, LLC (the "LLC"), a limited liability company for which we serve as the managing member. The LLC's only asset is an aircraft and the LLC was formed for the purpose of owning and operating the aircraft. We consolidate the entity based on a controlling financial interest. In 2010, we commenced activities to divest the asset and dissolve the entity, which will not have a material impact on our financial statements.

NOTE 16 - TRANSACTIONS WITH AFFILIATES

Amounts due from/to the affiliated partnership are primarily related to derivative positions and, to a lesser extent, unbilled well lease operating expenses, and costs resulting from audit and tax preparation services. We enter into derivative instruments for our own production as well as for our 29 affiliated partnerships' production. As of December 31, 2010, we had a payable to affiliates of $20.3 million representing their designated portion of the fair value of our gross derivative assets and a receivable from affiliates of $14.6 million representing their designated portion of the fair value of our gross derivative liabilities.

Our natural gas marketing segment manages the marketing of natural gas for PDCM and our affiliated partnerships with production in the Appalachian Basin. Our sales from natural gas marketing include \$0.7 million, \$0.5 million and \$1.5 million in 2010, 2009 and 2008, respectively, related to the marketing of natural gas on behalf of PDCM and our affiliated partnerships. Our cost of natural gas marketing include \$0.6 million, \$0.5 million and \$1.5 million for 2010, 2009 and 2008, respectively, related to these sales.

We provide certain well operating and administrative services for PDCM. Amounts billed to PDCM for these services were \$11.1 million in 2010. Our statements of operations include only our proportionate share of these billings: \$3.9 million, \$0.9 million and \$1.9 million is reflected in production costs, exploration expense and general and administrative expense, respectively.

Through June 2009, we provided natural gas and crude oil well drilling services to our affiliated partnerships. As part of these services, we sold to them at cost the natural gas and crude oil leases upon which the wells were drilled. For the year ended December 31, 2008, we sold to our affiliated partnerships leases in the amount of \$0.5 million. Further, we provide well operations and pipeline services to our affiliated partnerships. The majority of all of our revenue and expenses related to well operations and pipeline income are associated with services provided to our affiliated partnerships. See Note 13 for the natural gas and crude oil well drilling revenue recognized in 2009 and 2008.

NOTE 17 - BUSINESS SEGMENTS

We separate our operating activities into two segments: natural gas and crude oil sales and natural gas marketing. All material inter-company accounts and transactions between segments have been eliminated.

Natural Gas and Crude Oil Sales. Our natural gas and crude oil sales segment includes all of our natural gas and crude oil properties. The segment represents revenues and expenses from the production and sale of natural gas, NGL and crude oil. Segment revenue includes natural gas, NGL and crude oil sales, commodity price risk management, net and well operation and pipeline income. Segment income (loss) consists of segment revenue less production cost, exploration expense, impairment of proved natural gas and crude oil properties, direct general and administrative expense and DD&A expense. Segment DD&A expense was \$105.9 million for 2010, \$123.2 million for 2009 and \$98.9 million for 2008.

Natural Gas Marketing. Our natural gas marketing segment purchases, aggregates and resells natural gas produced by us and others. Segment income (loss) primarily represents sales from natural gas marketing and direct interest income less costs of natural gas marketing and direct general and administrative expense.

Unallocated amounts. Unallocated income includes unallocated other revenue less corporate general administrative expense, corporate DD&A expense, interest income and interest expense.

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The following tables present our segment information.

	2010	2009	2008
	(in thousands)		
Year Ended December 31,			
Revenues:			
Natural gas and crude oil sales	$278,576	$171,262	$443,193
Natural gas marketing	69,071	59,595	129,015
Unallocated	—	19	293
Total	$347,647	$230,876	$572,501
Segment income (loss) before income taxes:			
Natural gas and crude oil sales	$85,810	$(34,382)	$229,772
Natural gas marketing	1,063	1,967	1,242
Unallocated	(78,760)	(92,757)	(67,846)
Total	$8,113	$(125,172)	$163,168
Expenditures for segment long-lived assets:			
Natural gas and crude oil sales	$319,268	$140,431	$316,959
Unallocated	1,506	2,602	6,194
Total	$320,774	$143,033	$323,153
As of December 31,			
Segment assets:			
Natural gas and crude oil sales	$1,313,805	$1,117,625	
Natural gas marketing	16,338	22,614	
Unallocated	53,701	75,553	
Assets held for sale	5,191	34,535	
Total	$1,389,035	$1,250,327	

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SUPPLEMENTAL INFORMATION - UNAUDITED

NATURAL GAS AND CRUDE OIL INFORMATION - UNAUDITED

Net Proved Reserves

All of our natural gas, NGL and crude oil reserves are located in the U.S. We utilized the services of independent petroleum engineers to estimate our natural gas, crude oil, condensate and NGL reserves. As of December 31, 2010, substantially all of our reserve estimates were based on reserve reports prepared by Ryder Scott Company, L.P. ("Ryder Scott"). For our Appalachian Basin reserves, our internal reserve engineers estimated approximately three percent of the total proved developed natural gas reserves and approximately one percent of total proved undeveloped natural gas reserves. For each of the years in the two-year period ended December 31, 2009, our reserve estimates for the Rocky Mountain Region and Fort Worth Basin were prepared by Ryder Scott and our reserve estimates for the Appalachian and Michigan Basins were based on reserve reports prepared by Wright & Company. These reserve estimates have been prepared in compliance with professional standards and the reserves definitions prescribed by the SEC.

Proved reserves estimates may change, either positively or negatively, as additional information becomes available and as contractual, economic and political conditions change. Our net proved reserve estimates have been adjusted as necessary to reflect all contractual agreements, royalty obligations and interests owned by others at the time of the estimate. Proved developed reserves are the quantities of natural gas, NGL and crude oil 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.

The price used to estimate our reserves, by commodity, are presented below.

	Price Used to Estimate Reserves		
As of December 31,	Crude Oil	Natural Gas (1)	NGLs (1)
2010 (2)	$71.95	$3.54	$34.12
2009 (2)	54.64	3.17	—
2008 (3)	37.85	4.98	—

(1) Prior to 2010, NGLs were included in natural gas, which impacts the comparability for 2010 to 2009 and 2008.
(2) For 2010 and 2009, represents a 12-month average price calculated as the unweighted arithmetic average of the price on the first day of each month, January through December.
(3) For 2008, represents the price in effect as of December 31 for the respective commodity.

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The following tables present the changes in our estimated quantities of proved reserves.

	Natural Gas (MMcf)	Crude Oil, Condensate and NGLs (MBbls) (1)	Total (MMcfe)
Proved Reserves:			
Proved reserves, January 1, 2008	593,563	15,338	685,591
Revisions of previous estimates	(25,216)	(1,538)	(34,444)
Extensions, discoveries and other additions			
Rocky Mountain Region	100,323	2,354	114,447
Appalachian Basin	24,875	—	24,875
Purchases of reserves			
Rocky Mountain Region	1,712	106	2,348
Appalachian Basin	83	—	83
Other	46	—	46
Dispositions	(769)	(63)	(1,147)
Production	(31,760)	(1,160)	(38,720)
Proved reserves, December 31, 2008	662,857	15,037	753,079
Revisions of previous estimates	(101,923)	2,957	(84,181)
Extensions, discoveries and other additions			
Rocky Mountain Region	79,574	1,322	87,506
Appalachian Basin	3,190	—	3,190
Purchases of reserves			
Rocky Mountain Region	648	47	930
Appalachian Basin	59	—	59
Other	63	—	63
Dispositions	(7)	(1)	(13)
Production	(35,536)	(1,292)	(43,288)
Proved reserves, December 31, 2009	608,925	18,070	717,345
Revisions of previous estimates	6,504	8,823	59,442
Extensions, discoveries and other additions			
Rocky Mountain Region	56,524	3,058	74,872
Appalachian Basin	35,092	—	35,092
Purchases of reserves			
Rocky Mountain Region	15,781	1,322	23,713
Permian Basin	5,139	4,576	32,595
Appalachian Basin	220	—	220
Dispositions	(43,690)	(55)	(44,020)
Production	(27,189)	(1,909)	(38,643)
Proved reserves, December 31, 2010	657,306	33,885	860,616

(1) Prior to 2010, NGLs were included in natural gas, which impacts the comparability for 2010 to 2009 and 2008. In 2010, NGLs represented 7.4% of total proved reserves.

Proved Developed Reserves, as of:			
January 1, 2008	286,570	5,219	317,884

December 31, 2008	297,041	5,438	329,669
December 31, 2009	258,375	6,244	295,839
December 31, 2010	227,341	12,300	301,141
Proved Undeveloped Reserves, as of:			
January 1, 2008	306,993	10,119	367,707
December 31, 2008	365,816	9,599	423,410
December 31, 2009	350,550	11,826	421,506
December 31, 2010	429,965	21,585	559,475

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	Developed (MMcfe)	Undeveloped	Total
Beginning proved reserves, January 1, 2009	329,669	423,410	753,079
Undeveloped reserves transferred to developed	14,952	(14,952)	—
Revisions of previous estimates	(943)	(83,238)	(84,181)
Extensions, discoveries and other additions	(5,163)	95,859	90,696
Purchases of reserves	625	427	1,052
Dispositions	(13)	—	(13)
Production	(43,288)	—	(43,288)
Ending proved reserves, December 31, 2009	295,839	421,506	717,345
Undeveloped reserves transferred to developed	17,967	(17,967)	—
Revisions of previous estimates	16,782	42,660	59,442
Extensions, discoveries and other additions	21,572	88,392	109,964
Purchases of reserves	28,728	27,800	56,528
Dispositions	(41,104)	(2,916)	(44,020)
Production	(38,643)	—	(38,643)
Ending proved reserves, December 31, 2010	301,141	559,475	860,616

2010 Activity. In 2010, we revised our previous estimate of proved reserves upward by 59.4 Bcfe. The revision was primarily due to an increase of 55.6 Bcfe due to asset performance, 35.9 Bcfe due to higher commodity pricing, 28.1 Bcfe due to the impact of evaluating NGLs as a separate stream and 1.5 Bcfe due to interest adjustments. This was partially offset by a decrease of 58.7 Bcfe due to adjustments for reserve decreases for geological reasons or reclassification of prior period proved undeveloped reserves to probable reserves due to aging and 3 Bcfe due to increased operating costs. New discoveries and extensions of 110 Bcfe in 2010 are due to drilling of 213 gross wells and the addition of new proved undeveloped reserves: 35.1 Bcfe were added in the Appalachian Basin and 74.9 Bcfe were added in the Rocky Mountain Region (29.4 Bcfe in Wattenberg Field, 36.2 Bcfe in Grand Valley Field, 9.1 Bcfe in the NECO area and 0.2 Bcfe in North Dakota) and West Texas. We acquired 56.5 Bcfe of proved reserves, approximately 32.6 Bcfe through two acquisitions in the Permian Basin and 23.9 Bcfe in the Rocky Mountains and the Appalachian basin due to the repurchase of the 2004 Partnerships as well as the purchase of interest in some of our other existing properties. Of the 23.9 Bcfe, 12.8 Bcfe were acquired in the Wattenberg Field, 10.9 Bcfe were acquired in the Piceance Basin with the remaining 0.2 Bcfe split between the Appalachian Basin and North Dakota. Total dispositions of 44 Bcfe in 2010 includes the deconsolidation of PDCM, or 28.9 Bcfe, and the sale of all of our Michigan assets, or 15.1 Bcfe, to an unaffiliated third party.

2009 Activity. In 2009, we revised our previous estimate of proved reserves downward by 84.2 Bcfe. The revision was primarily due to a decrease of 99.5 Bcfe due to lower commodity pricing and 45.1 Bcfe due to adjustments to reserves removed or reclassified due to new rules limiting proved undeveloped reserves locations to those scheduled to be drilled within the next five years. The downward adjustments were partially offset by an increase of 41.4 Bcfe due to decreased operating costs, 1 Bcfe due to interest adjustments and 17.9 Bcfe due to asset performance. New discoveries and extensions of 90.7 Bcfe in 2009 were due to drilling of 100 gross wells and the addition of new proved undeveloped reserves: 3.2 Bcfe in the Appalachian Basin and 87.5 Bcfe in the Rocky Mountain Region (13.7 Bcfe in Wattenberg Field, 73.3 Bcfe in Grand Valley Field, and 0.5 Bcfe in North Dakota). We acquired 1.1 Bcfe of proved reserves through the purchase of interest in some of our existing properties. We acquired reserves primarily in the Wattenberg Field with the remaining reserves split between the Appalachian Basin, Michigan Basin, Piceance

Basin and North Dakota. We sold a minimal amount of reserves to unaffiliated third parties in the Wattenberg Field.

2008 Activity. In 2008, we revised our previous estimate of proved reserves downward by 34.4 Bcfe. The revision was primarily due to a decrease of 50 Bcfe due to lower commodity prices, 25.8 Bcfe due to increased operating costs, and 14.4 Bcfe due to adjustments to proved undeveloped reserve values, partially offset by an increase of 55.8 Bcfe due to asset performance. New discoveries and extensions of 139.3 Bcfe in 2008 were due to drilling of 229 net wells and the addition of new proved undeveloped reserves: 24.9 Bcfe in the Appalachian Basin and 114.4 Bcfe in the Rocky Mountain Region (26.6 Bcfe in the Wattenberg Field, 80 Bcfe in Grand Valley Field, and 7.8 Bcfe in NECO and other areas). We acquired 2.5 Bcfe of proved reserves through the purchases of interest in some of our existing properties. We acquired reserves primarily in the Wattenberg Field with the remaining reserves being split between the Appalachian, Michigan, and Piceance Basins, the NECO area and North Dakota. We sold proved reserves of 1.1 Bcfe to unaffiliated third parties and to our sponsored partnerships for drilling activity.

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Results of Operations for Natural Gas and Crude Oil Producing Activities

The results of operations for natural gas and crude oil producing activities are presented below. The results include activities related to both continuing and discontinued operations and exclude activities related to natural gas marketing and well operations and pipeline services.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Revenue:			
Natural gas, NGL and crude oil sales	$216,159	$179,093	$321,877
Commodity price risk management gain (loss), net	59,891	(10,053)	127,838
	276,050	169,040	449,715
Expenses:			
Production costs	61,544	57,825	72,518
Exploration expense	20,291	21,961	32,280
DD&A expense	103,303	125,415	100,207
Impairment of proved natural gas and oil properties	4,666	926	12,825
	189,804	206,127	217,830
Results of operations for natural gas and crude oil producing activities before provision for income taxes	86,246	(37,087)	231,885
Provision (benefit) for income taxes	5,925	(13,355)	81,577
Results of operations for natural gas and crude oil producing activities, excluding corporate overhead and interest costs	$80,321	$(23,732)	$150,308

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. DD&A 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.

Costs Incurred in Natural Gas and Crude Oil Property Acquisition, Exploration and Development Activities

Costs incurred in natural gas and crude oil property acquisition, exploration and development are presented below.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Acquisition of properties: (1)			
Proved properties	$87,241	$2,251	$6,147
Unproved properties	84,636	5,867	6,890
Development costs (2)	138,018	72,416	257,656

Exploration costs: (3)			
Exploratory drilling	21,223	18,317	26,499
Geological and geophysical	2,367	1,788	2,121
Total costs incurred	$333,485	$100,639	$299,313

(1) Property acquisition costs - represent costs incurred to purchase, lease or otherwise acquire a property.

(2) Development costs - represents 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 natural gas, NGLs and crude oil. Of these costs incurred for the years ended December 31, 2010, 2009 and 2008, $37.4 million, $44.4 million and

$66 million, respectively, were incurred to convert proved undeveloped reserves to proved developed reserves from the prior year end.

(3) Exploration costs - represents costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing natural gas, NGL and crude oil reserves.

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Capitalized Costs Related to Natural Gas and Crude Oil Producing Activities

Aggregate capitalized costs related to natural gas and crude oil exploration and production activities with applicable accumulated DD&A are presented below:

	As of December 31, 2010 (in thousands)	2009
Proved natural gas and crude oil properties (1)	$1,481,191	$1,329,666
Unproved natural gas and crude oil properties	85,502	38,626
	1,566,693	1,368,292
Less accumulated DD&A	492,501	428,754
	$1,074,192	$939,538

(1) As of December 31, 2010, we had no capitalized proved undeveloped natural gas and crude oil properties disclosed as such for longer than 5 years.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Reserves

Presented in the following table is information with respect to the standardized measure of discounted future net cash flows relating to proved reserves.

	As of December 31, 2010 (in thousands)	2009	2008
Future estimated cash flows	$4,361,095	$2,915,377	$3,867,461
Future estimated production costs	(1,418,044)	(1,088,337)	(1,325,362)
Future estimated development costs	(1,119,604)	(825,139)	(1,100,533)
Future estimated income tax expense	(508,805)	(237,790)	(384,676)
Future net cash flows	1,314,642	764,111	1,056,890
10% annual discount for estimated timing of cash flows	(826,224)	(416,475)	(700,085)
Standardized measure of discounted future estimated net cash flows	$488,418	$347,636	$356,805

Future cash inflows are computed by applying prices used in estimating the entity's 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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The following table presents the principal sources of change in the standardized measure of discounted future estimated net cash flows.

	Year Ended December 31,		
	2010	2009	2008
	(in thousands)		
Sales of natural gas, NGL and crude oil production, net of production costs	$(163,104)	$(136,568)	$(261,692)
Net changes in prices and production costs	180,124	(107,766)	(479,894)
Extensions, discoveries, and improved recovery, less related costs	88,637	30,851	80,859
Sales of reserves	(24,174)	(21)	(2,012)
Purchase of reserves	45,538	1,266	4,280
Development costs incurred during the period	44,491	40,603	88,008
Revisions of previous quantity estimates	47,884	(46,226)	(79,536)
Changes in estimated income taxes	(105,557)	38,371	239,054
Net changes in future development costs	(41,595)	101,765	(87,625)
Accretion of discount	35,951	49,434	122,409
Timing and other	32,586	19,122	(20,117)
Total	$140,781	$(9,169)	$(396,266)

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.

QUARTERLY FINANCIAL INFORMATION - UNAUDITED

Quarterly financial data for the years ended December 31, 2010 and 2009, is presented below. The sum of the quarters may not equal the total of the year's net income or loss per share attributable to shareholders due to changes in the weighted average shares outstanding throughout the year.

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	2010 Quarter Ended				
	March 31	June 30	September 30	December 31	Year Ended
	(in thousands, except per share data)				
Revenues:					
Natural gas, NGL and crude oil sales	$57,827	$48,729	$47,295	$55,793	$209,644
Sales from natural gas marketing	22,687	12,589	18,337	15,458	69,071
Commodity price risk management gain (loss), net	43,222	12,257	19,029	(14,617)	59,891
Well operations, pipeline income and other	2,589	2,148	2,159	2,145	9,041
Total revenues	126,325	75,723	86,820	58,779	347,647
Costs, expenses and other:					
Production costs	14,961	16,004	16,524	19,328	66,817
Cost of natural gas marketing	22,323	12,207	18,300	15,185	68,015
Exploration expense	6,418	3,830	3,712	6,306	20,266
General and administrative expense	10,694	9,855	10,426	11,213	42,188
Depreciation, depletion and amortization	27,458	26,945	28,024	26,816	109,243
Gain on sale of leaseholds	—	(96)	(57)	(21)	(174)
Total costs, expenses and other	81,854	68,745	76,929	78,827	306,355
Income (loss) from operations	44,471	6,978	9,891	(20,048)	41,292
Interest income	5	34	21	11	71
Interest expense	(7,800)	(7,672)	(8,174)	(9,604)	(33,250)
Income (loss) from continuing operations before income taxes	36,676	(660)	1,738	(29,641)	8,113
Provision (benefit) for income taxes	13,804	(238)	(1,156)	(11,218)	1,192
Income (loss) from continuing operations	22,872	(422)	2,894	(18,423)	6,921
Income (loss) from discontinued operations, net of tax	797	(2,313)	460	69	(987)
Net income (loss)	23,669	(2,735)	3,354	(18,354)	5,934
Less: net loss attributable to noncontrolling interests	(55)	(6)	(5)	(214)	(280)
Net income (loss) attributable to shareholders	$23,724	$(2,729)	$3,359	$(18,140)	$6,214
Amounts attributable to Petroleum Development Corporation shareholders:					
Income (loss) from continuing operations	$22,927	$(416)	$2,899	$(18,209)	$7,201
Income (loss) from discontinued operations, net of tax	797	(2,313)	460	69	(987)
Net income (loss) attributable to shareholders	$23,724	$(2,729)	$3,359	$(18,140)	$6,214
Earnings (loss) per share attributable to shareholders:					
Basic					
Income (loss) from continuing operations	$1.19	$(0.03)	$0.15	$(0.86)	$0.37
Income (loss) from discontinued operations	0.04	(0.12)	0.02	—	(0.05)
Net income (loss) attributable to shareholders	$1.23	$(0.15)	$0.17	$(0.86)	$0.32

Diluted					
Income (loss) from continuing operations	$1.19	$(0.03)	$0.15	$(0.86)	$0.36
Income (loss) from discontinued operations	0.04	(0.12)	0.02	—	(0.05)
Net income (loss) attributable to shareholders	$1.23	$(0.15)	$0.17	$(0.86)	$0.31
Weighted average common shares outstanding					
Basic	19,191	19,213	19,250	21,026	19,674
Diluted	19,287	19,213	19,406	21,026	19,821

PETROLEUM DEVELOPMENT CORPORATION
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	2009 Quarter Ended				
	March 31	June 30	September 30	December 31	Year Ended
	(in thousands, except per share data)				
Revenues:					
Natural gas, NGL and crude oil sales	$37,884	$39,745	$42,050	$51,563	$171,242
Sales from natural gas marketing	20,832	11,306	11,062	16,395	59,595
Commodity price risk management gain (loss), net	23,683	(23,284)	(13,813)	3,361	(10,053)
Well operations, pipeline income and other	2,647	2,771	2,239	2,435	10,092
Total revenues	85,046	30,538	41,538	73,754	230,876
Costs, expenses and other:					
Production costs	15,749	13,643	14,332	18,379	62,103
Cost of natural gas marketing	20,346	10,895	10,179	16,198	57,618
Exploration expense	5,640	3,085	2,469	6,983	18,177
Impairment of proved natural gas and crude oil properties	—	—	926	—	926
General and administrative expense	12,094	14,784	9,627	17,480	53,985
Depreciation, depletion and amortization	33,532	32,610	31,315	29,298	126,755
Gain on sale of leaseholds	(120)	—	—	(350)	(470)
Total costs, expenses and other	87,241	75,017	68,848	87,988	319,094
Loss from operations	(2,195)	(44,479)	(27,310)	(14,234)	(88,218)
Interest income	20	12	208	14	254
Interest expense	(8,383)	(9,420)	(9,221)	(10,184)	(37,208)
Loss from continuing operations before income taxes	(10,558)	(53,887)	(36,323)	(24,404)	(125,172)
Benefit for income taxes	(4,355)	(20,635)	(13,469)	(6,595)	(45,054)
Loss from continuing operations	(6,203)	(33,252)	(22,854)	(17,809)	(80,118)
Income from discontinued operations, net of tax	484	157	(1,921)	305	(975)
Net loss	(5,719)	(33,095)	(24,775)	(17,504)	(81,093)
Less: net loss attributable to noncontrolling interests	(16)	(16)	(299)	(1,485)	(1,816)
Net loss attributable to shareholders	$(5,703)	$(33,079)	$(24,476)	$(16,019)	$(79,277)
Amounts attributable to Petroleum Development Corporation shareholders:					
Loss from continuing operations	$(6,187)	$(33,236)	$(22,555)	$(16,324)	$(78,302)
Income from discontinued operations, net of tax	484	157	(1,921)	305	(975)
Net loss attributable to shareholders	$(5,703)	$(33,079)	$(24,476)	$(16,019)	$(79,277)
Earnings (loss) per share attributable to shareholders:					
Basic					
Loss from continuing operations	$(0.41)	$(2.24)	$(1.33)	$(0.85)	$(4.76)
Income from discontinued operations	0.03	0.01	(0.11)	0.01	(0.06)
Net loss attributable to shareholders	$(0.38)	$(2.23)	$(1.44)	$(0.84)	$(4.82)
Diluted					

Loss from continuing operations	$(0.41)	$(2.24)	$(1.33)	$(0.85)	$(4.76)
Income from discontinued operations	0.03	0.01	(0.11)	0.01	(0.06)
Net loss attributable to shareholders	$(0.38)	$(2.23)	$(1.44)	$(0.84)	$(4.82)
Weighted average common shares outstanding					
Basic	14,793	14,811	16,962	19,172	16,448
Diluted	14,793	14,811	16,962	19,172	16,448

PETROLEUM DEVELOPMENT CORPORATION
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FINANCIAL STATEMENT SCHEDULE

Schedule II -VALUATION AND QUALIFYING ACCOUNTS

Description	Beginning Balance January 1	Deconsolidation/Purchase Price Adjustment for PDCM	Charged to Costs and Expenses	Deductions (1)	Ending Balance December 31
	(in thousands)				
2010:					
Allowance for doubtful accounts	$548	135	$307	$34	$686
Valuation allowance for state tax benefits	747	—	—	747	—
Valuation allowance for unproved natural gas and crude oil properties	15,001	19	6,120	4,106	16,996
2009:					
Allowance for doubtful accounts	$537	—	$120	$109	$548
Valuation allowance for state tax benefits	—	—	747	—	747
Valuation allowance for unproved natural gas and crude oil properties	12,870	—	7,279	5,148	15,001
2008:					
Allowance for doubtful accounts	$357	—	$180	$—	$537
Valuation allowance for unproved natural gas and crude oil properties	2,365	—	12,798	2,293	12,870

(1) For allowance for doubtful accounts, deductions represent the write-off of accounts receivable deemed uncollectible. For allowance for unproved natural gas and crude oil properties, deductions represent accumulated amortization of expired or abandoned unproved natural gas and crude oil properties. For allowance for state tax benefits, deductions represent expired or unutilized state tax benefits.

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