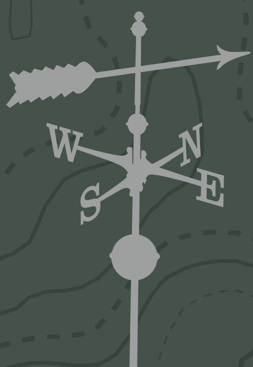


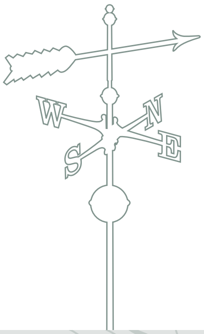
A CLEAR SENSE OF DIRECTION

CABOT OIL & GAS CORPORATION

2009 ANNUAL REPORT

CABOT OIL & GAS CORPORATION, headquartered in Houston, Texas is a leading independent natural gas producer, with its entire resource base located in the continental United States. The Company's North Region is based in Pittsburgh, Pennsylvania and is responsible for the Pennsylvania, West Virginia, and Rocky Mountain assets. The South Region office, located in Houston, Texas, is responsible for the Texas and Mid-Continent assets.

CABOT'S CLEAR SENSE OF DIRECTION HAS POSITIONED THE COMPANY TO FOCUS ITS 2010 EFFORTS ON EXECUTING IN SOME OF THE HOTTEST PLAYS.



TO OUR SHAREHOLDERS:

LAST YEAR I MADE COMMENTS ABOUT THE HIGH DEGREE OF UNCERTAINTY FACING THE BUSINESS COMMUNITY ACROSS ALL SECTORS, INCLUDING A NEAR SHUT DOWN OF THE CREDIT MARKETS. WHILE NATIONAL AND INTERNATIONAL CHALLENGES CONTINUE TO EXIST FOR BUSINESS AND THE FINANCIAL MARKETS, I AM PLEASED TO REPORT, CABOT NOT ONLY WEATHERED THE CRISIS VERY WELL, BUT THRIVED IN 2009.

The weather vane on the front cover succinctly symbolizes the strategic steps Cabot took in 2009 – defining our *sense of direction and focus*. As we focused investments towards new initiatives, our existing regional footprint was not geographically conducive for existing field operations and therefore, lacked efficiency regarding allocation of our talented workforce. In response, the Company specifically:

- Sold its Canadian operations in April refocusing efforts solely in the lower 48
- Created a new north and south regional designation to streamline reporting and create operating efficiencies
- Closed its west region office in Denver consolidating those operations in both Pittsburgh (Rocky Mountains) and Houston (Mid-Continent)
- Closed its West Virginia region office in Charleston and consolidated it to Pittsburgh
- Relocated its corporate headquarters within Houston

From this new, streamlined organization, our 2009 operational efforts were focused on:

- Further delineation and expansion of our Marcellus acreage position
- Infrastructure build-out in support of our growth in the Marcellus
- Exploiting new prospective horizons throughout our east Texas operations
- Expanding oil related projects in Texas

AS WE HAVE ENTERED 2010, THE SUPPLY AND DEMAND DYNAMIC EXPERIENCED DURING 2009 REMAINS FIRMLY IN PLACE.

I am pleased to report that all 2009 initiatives were accomplished with significant levels of success. Also, I am particularly thankful for the many loyal employees and their families for the tireless commitment through our reorganization process. In 2009, the Company's Marcellus program quadrupled in producing wells (increasing horizontal producing wells from one to 15), added over 20,000 acres to our focus Marcellus position and doubled our pipeline and compression capability. (See page 9 for a more detailed Marcellus discussion). In east Texas we had success with our initial efforts in the Haynesville Shale and the Cotton Valley Taylor horizontal wells. Additionally, we refocused our County Line efforts on oil to take advantage of the enhanced yield as a result of the oil prices. Also, as part of our objective to stay within cash flow, we deferred completions on 16 wells drilled to the James and Cotton Valley in east Texas. These will be completing in early 2010. Operationally, we added significantly to our shale knowledge base in 2009 and solidified the merits of all our key plays.

In terms of financial metrics, 2009 measured up far better than anyone expected when the year started with financial numbers matching or improving on 2007 (but short of 2008 records) and key operating metrics reaching new highs. Specifically with:

- Net income of $148.3 million, or $1.43 per share
- Discretionary cash flow of $604.6 million
- Reserve adds of 463 Bcfe from drilling
- Total reserves of 2,060 Bcfe (a new high)
- Full year production of 103 Bcfe (a new high)

Additionally, our operating prudency was reinforced with our ability to place a new upsized credit facility with four new banks in the tough market. At year-end our debt level was down year-over-year and the new credit facility was less than one-third drawn upon. This financial strength, combined with the Company's acreage position in two of the hottest shale plays, gives credence to our excitement for 2010.

LOOKING FORWARD

As we have entered 2010, the supply and demand dynamic experienced during 2009 remains firmly in place. That is, an abundant supply of natural gas and diminished demand, due to a slow economic recovery. We have planned our 2010 program with these facts in mind. Our capital allocation is targeted around anticipated cash flow for 2010 and is once again predominately directed to the Marcellus Shale in Pennsylvania and east Texas for Haynesville/Bossier Shale, Cotton Valley Taylor Sand and Pettet oil. One difference for

2010 is that our Marcellus effort is planned to utilize over two-thirds of the budget versus a 60/40 split between Pennsylvania and east Texas in 2009. With this allocation mix we anticipate our financial and operating metrics to be enhanced.

In addition to our own internal goals and plans, Cabot is part of a new venture called America's Natural Gas Alliance which was formed in 2009 to help educate consumers, policy makers and even environmental groups about the merits of natural gas. Our industry previously has not done a great job communicating to the market and to Washington the valuable attributes of natural gas.

Natural gas needs to be part of the long-term energy solution for the United States as a clean fuel that can move us towards energy independence. Cabot is a definite contributor to this opportunity as a Company with over two Tcfe of reserves and over 12 Tcfe of total resource potential in the lower 48 states that are 98 percent natural gas. Clearly this message is being heard throughout our Nation.

As we have closed another year and reflect on those events that have transpired and what opportunities that lie ahead, I am more encouraged than ever before for Cabot growth and prosperity, as is the entire management team. I want to thank our board of directors and our talented employees for their commitment to Cabot Oil & Gas Corporation. For the shareholders, please take comfort in the fact that your Company has years of organic growth on the books, along with a skill-set, knowledge base and a strong balance sheet to exploit it.

Lastly, I must offer my sincere thanks and gratitude to Mike Walen (Senior Vice President and Chief Operating Officer) and Chuck Smyth (Vice President, Controller and Treasurer) for their combined nearly four decades of service to Cabot Oil & Gas. Their contributions and insights have left a legacy we will benefit from for years. We are on the leading edge in two exciting shale plays and with our financial strength I look forward to years of growth and value creation.

Sincerely,

Dan O. Dinges
Chairman, President and Chief Executive Officer

NORTH REGION

CLOSE TO MARKET

IN 2009, CABOT’S MARCELLUS PROGRAM QUADRUPLED IN PRODUCING WELLS (INCREASING HORIZONTAL PRODUCING WELLS FROM ONE TO 15), ADDED OVER 20,000 ACRES TO ITS FOCUS MARCELLUS POSITION AND DOUBLED ITS PIPELINE AND COMPRESSION CAPABILITY.

Cabot Oil & Gas established its North Region office in Pittsburgh, Pennsylvania in October 2009.

MARCELLUS SHALE

CABOT'S POSITION IN THE MARCELLUS SHALE IS THE CLOSEST AVAILABLE SIGNIFICANT RESOURCE BASE TO THE NORTHEAST UNITED STATES, THE SINGLE LARGEST MARKET FOR NATURAL GAS. PROXIMITY TO THIS MARKET CREATES A PRICE PREMIUM, WHICH COUPLED WITH FINDING AND DEVELOPMENT COSTS WELL BELOW THE AVERAGE NORTH AMERICAN SHALE PLAY, GIVES MARCELLUS GAS A SIGNIFICANT ECONOMIC ADVANTAGE.

This advantage, plus Cabot's extensive acreage position in the core of this lucrative play, gives the Company a long-term opportunity that it will focus on for years to come.

GROWTH

In 2009, the Company drilled 30 horizontal wells and 21 vertical wells, compared to five horizontal and 15 vertical in 2008. At the time of publication, Cabot had 193,000 gross acres in northeastern Pennsylvania and was producing approximately 100 Mmcf per day gross with a back log of 22 completions.

73

HORIZONTAL WELLS plus eight vertical wells currently planned for 2010.

275 Mmcf

PER DAY SECURED of firm take-away with an additional 100 Mmcf per day of options available.

23 Miles

OF PIPE TO DATE with an additional 30.5 miles anticipated to be complete in 2010.

2010 INITIATIVES

In 2009 Cabot's Marcellus program was in a research and development stage, testing ideas and working to understand spacing and optimal stimulation intervals. In 2010 this program will transition into a full development stage while continuing to explore new techniques to enhance efficiencies in timing, costs and performance. Changes in 2010 to contribute to these efficiencies include:

- Increasing number of horizontal wells per pad to six, up from two per pad in 2009
- Downspacing to 1,000' in 2010 from 2,000' in 2009
- Drilling longer laterals with shorter stage spacing
- Multiple back-to-back stimulations on same pad

The Company plans to more than double the number of horizontal Marcellus wells drilled in 2009, with 73 horizontal wells plus eight vertical wells currently planned for 2010.

Even though lease bonuses have escalated in the last few months, Cabot continues to be competitive in acquiring leases. In 2010 the Company is committed to acquiring acreage to fill in its existing blocks and consolidating and growing its position in Susquehanna County. Cabot's focus remains on this highly coveted area with some of the thickest sections of the Marcellus at over 400'. The Company's existing portfolio of acreage in this area has over a 10 Tcf resource potential of high quality gas. Cabot is currently shooting 110 square miles of 3-D seismic survey and plans to expand the survey by 225 square miles during 2010. This new data will enhance the Company's location selection process.

Much of the leased property is not immediately adjacent to major natural gas pipelines, however, Cabot has done an excellent job of expanding infrastructure to handle the physical production and to connect individual wells to the major pipelines. The Company has laid 23 miles of pipe with an additional 30.5 miles anticipated to be completed in 2010. At year end 2009, capacity at Cabot's Teel compression station was 110 Mmcf per day. An additional compression station with capacity of 165 Mmcf per day is scheduled to be completed by this summer. The Company has secured 275 Mmcf per day of firm take-away with an option for an additional 100 Mmcf per day. Cabot is also evaluating other options for both compression and firm take-away.

SOUTH REGION

CAPITALIZING ON PRIOR YEAR INVESTMENTS

IN EAST TEXAS CABOT SUCCESSFULLY DRILLED HORIZONTALS IN THE HAYNESVILLE SHALE, PETTET LIME AND THE COTTON VALLEY TAYLOR. ADDITIONALLY, THE COMPANY REFOCUSED ITS COUNTY LINE EFFORTS ON OIL TO TAKE ADVANTAGE OF THE DISCONNECT BETWEEN NATURAL GAS AND OIL PRICES.

HAYNESVILLE · PETTET · MINDEN

CABOT HAS EXTENSIVE EAST TEXAS INVENTORY THANKS TO PRIOR YEAR INVESTMENTS. WHILE EACH FIELD VARIES IN TERMS OF GEOLOGY AND THE RESOURCES WITHIN, THEY SHARE THE STACKED PAY CONCEPT. THIS AFFORDS FLEXIBILITY IN SELECTING LOCATIONS AND TARGETING ZONES THAT PROVIDE THE HIGHEST ECONOMIC RETURNS BASED ON THE UNDERLYING OR EXPECTED COMMODITY PRICE ENVIRONMENT.

HAYNESVILLE

Over the last few years Cabot has been focused on growing and developing its acreage in the County Line field. The Company is developing a new east Texas core of the Haynesville shale play, based on recent partner success drilling the Haynesville shale formation and success of other wells offsetting Cabot's acreage. This play extends into the Company's County Line acreage.

Cabot's first horizontal Haynesville shale well, the Burrows No. 1 H in San Augustine County, had an IP of 20.7 Mmcfe per day. This initial discovery solidified the thesis that this shale was prolific and on trend with the Haynesville success in Louisiana. As a result, the Company drilled two non-operated horizontal Haynesville shale wells in 2009, and is planning for 12 gross wells in 2010. This number allows Cabot to delineate the aereal extent of the play.

Cabot has 63,000 gross acres (33,000 net), which provides an expectation for the Company of between 150 to 250 gross locations with a resource potential between 800 Bcf and 1.8 Tcf.

20.7 Mmcfe

PER DAY initial production in San Augustine County.

136,850

GROSS ACRES of shale plays in the South Region.

PETTET

The Company's Pettet oil development in Shelby and San Augustine counties in east Texas continues to show superior results. During 2009, Cabot drilled 10 wells targeting the Pettet formation. Two have been completed with horizontal intervals ranging from 4,000' to 4,500' with between 10 to 14 stimulations. Individually, these wells had initial production rates between 450 to 950 barrels per day. The market differentials between oil prices and natural gas prices during 2009 and the outlook for 2010, together with the good well performance, establishes the Pettet as a very economic play for Cabot.

The Company plans to drill 11 Pettet wells in 2010. Cabot estimates it has 175 to 225 gross Pettet locations with a potential of 25 to 35 MMBO, plus 100 to 140 Bcf of natural gas.

MINDEN

In 2009, the Company completed its first horizontal Cotton Valley Taylor sand well with an initial rate of 9.5 Mmcf per day. This well performed extremely well with a 30-day average rate of 7.9 Mmcf per day. Strong rates are still present over 200 days after IP, with the first offset well being equally productive. These rates significantly enhance the economics for Cotton Valley development in the current environment. Cabot has identified 30 to 50 potential locations targeting the Taylor sand.

175-225

GROSS PETTET oil locations.

Financial Highlights

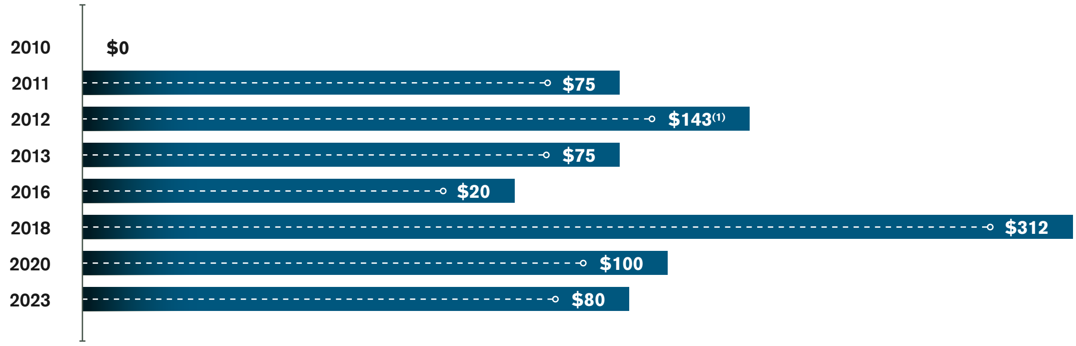
Income Statement *(In millions, except per share amounts)*		2007		2008		**2009**
Operating Revenue	$	732.2	$	945.8	**$**	**879.3**
Operating Expenses		470.9		626.8		**593.7**
Operating Income		274.7		372.0		**282.3**
Net Income		167.4		211.3		**148.3**
Per Share		1.73		2.10		**1.43**
Common Dividend Per Share	$	0.11	$	0.12	**$**	**0.12**
Average Common Shares Outstanding *(In thousands)*		96,978		100,737		**103,616**

Cash Flow		2007		2008		**2009**
Discretionary Cash Flow	$	472.7	$	608.7	**$**	**604.6**
Per Share		4.87		6.04		**5.83**
Cash from Operations		462.1		634.4		**614.1**
Cash from Investing		(589.9)		(1,452.3)		**(531.0)**
Cash from Financing		104.4		827.4		**(71.0)**
Net Cash	$	(23.4)	$	9.6	**$**	**12.1**

Balance Sheet		2007		2008		**2009**
Current Assets	$	217.5	$	460.6	**$**	**281.5**
Current Liabilities		248.3		378.9		**308.7**
Short-Term Debt		20.0		35.9		**-**
Long-Term Debt		330.0		831.1		**805.0**
Stockholders' Equity	$	1,070.3	$	1,790.6	**$**	**1,812.5**

(Successful Efforts Method)

Debt Maturity Schedule



(1) Debt associated with Revolving Credit Facility

Operational Highlights

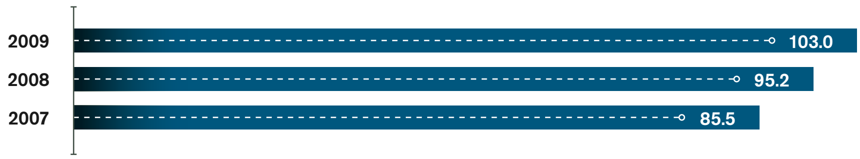
Wells Drilled	2007	2008	2009
Total Gross	461	432	143
Total Net	391	355	119
Gross Success Rate	96%	97%	95%

Proved Reserves	2007	2008	2009
Natural Gas *(Bcf)*	1,560.0	1,886.0	2,013.2
Oil, Condensate and Natural Gas Liquids *(Mmbbl)*	9.3	9.3	7.8
Total Proved *(Bcfe)*	1,615.9	1,942.0	2,059.9
Total Developed *(Bcfe)*	1,176.1	1,348.5	1,324.7
% Gas	97%	97%	98%
% Developed	73%	69%	64%

Reserve Additions	2007	2008	2009
Additions *(Bcfe)*	274.1	303.9	462.9
Drilling Additions, Revisions, and Purchases *(Bcfe)*	285.2	421.5	262.7
Reserve Replacement	333.8%	442.8%	255.2%

Finding & Development Costs	2007	2008	2009
Additions *($/Mcfe)*	$ 2.14	$ 2.25	$ 0.97
Additions, Revisions *($/Mcfe)*	2.09	2.77	1.70
Additions, Revisions, and Purchases *($/Mcfe)*	$ 2.07	$ 3.06	$ 1.70

Total Production *(Bcfe)*



Board of Directors

DIRECTORS

Dan O. Dinges
Chairman, President and Chief Executive Officer

Rhys J. Best
Former Chairman of the Board and Chief Executive Officer, Lone Star Technologies, Inc.

David M. Carmichael
Former Vice Chairman and Chairman of the Management Committee, KN Energy, Inc.

Robert L. Keiser
Former Chairman of the Board, Oryx Energy Company

Robert Kelley
Former Chairman of the Board, President and Chief Executive Officer, Noble Affiliates, Inc. (Subsequently renamed Noble Energy Inc.)

P. Dexter Peacock
Of Counsel, Andrews & Kurth L.L.P. Former Managing Partner, Andrews & Kurth L.L.P.

William P. Vititoe
Former Chairman of the Board, Chief Executive Officer and President, Washington Energy Company

COMMITTEES

AUDIT COMMITTEE
Robert Kelley – *Chairman*
Rhys J. Best
Robert L. Keiser

COMPENSATION COMMITTEE
William P. Vititoe – *Chairman*
David M. Carmichael
P. Dexter Peacock

EXECUTIVE COMMITTEE
P. Dexter Peacock – *Chairman*
Dan O. Dinges
David M. Carmichael

CORPORATE GOVERNANCE AND NOMINATIONS COMMITTEE
David M. Carmichael – *Chairman*
P. Dexter Peacock
William P. Vititoe

SAFETY AND ENVIRONMENTAL AFFAIRS COMMITTEE
Robert L. Keiser – *Chairman*
Rhys J. Best
Robert Kelley

Corporate Information

OFFICERS

Dan O. Dinges
Chairman, President and Chief Executive Officer

Michael B. Walen (Retiring 2010)
Senior Vice President, Chief Operating Officer

Scott C. Schroeder
Vice President, Chief Financial Officer

J. Scott Arnold
Vice President, Land and General Counsel

Robert G. Drake
Vice President, Information Services and Operational Accounting

Abraham D. Garza
Vice President, Human Resources

Jeffrey W. Hutton
Vice President, Marketing

Lisa A. Machesney
Vice President, Managing Counsel and Corporate Secretary

James M. Reid
Vice President and Regional Manager, South

Henry C. Smyth (Retiring 2010)
Vice President, Controller and Treasurer

Phillip L. Stalnaker
Vice President and Regional Manager, North

Todd M. Roemer
Controller

ANNUAL MEETING
The annual meeting of the shareholders will be held Tuesday, April 27, 2010, at 8:00 a.m. (Eastern) at the regional office in Pittsburgh, Pennsylvania.

CORPORATE OFFICE
Cabot Oil & Gas Corporation
Three Memorial City Plaza
840 Gessner, Suite 1400
Houston, TX 77024
P.O. Box 4544
Houston, Texas 77210-4544
(281) 589-4600
www.cabotog.com

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
PricewaterhouseCoopers LLP
1201 Louisiana, Suite 2900
Houston, Texas 77002

RESERVE ENGINEERS
Miller & Lents, Ltd
Oil & Gas Consultants
909 Fannin, Suite 1300
Houston, Texas 77010

INVESTOR RELATIONS
Additional copies of the Form 10-K are available without charge. Shareholders, securities analysts, portfolio managers and others who have questions or need additional information concerning the Company may contact:

Scott C. Schroeder
Vice President, Chief Financial Officer
(281) 589-4993
scott.schroeder@cabotog.com

TRANSFER AGENT/REGISTRAR
Wells Fargo Bank N.A.
Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075-1139
(800) 468-9716
www.wellsfargo.com/shareownerservices

General Inquiries:
Wells Fargo Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0856
(800) 468-9716

Certified/Overnight Mail:
Wells Fargo Shareowner Services
161 North Concord Exchange
South St. Paul, MN 55075-1139

TDD for Hearing Impaired:
(651) 450-4144

Telephone Number for Foreign Shareowners:
(877) 602-7599

CORPORATE GOVERNANCE MATTERS
On May 28, 2009, the Company's CEO, Dan O. Dinges, certified to the NYSE that he was not aware of any violation by the Company of NYSE corporate governance listing standards. Further, Mr. Dinges and the CFO, Scott C. Schroeder, made the requisite Section 302 certifications in the 2009 quarterly reports on Form 10-Q and the 2009 annual report on Form 10-K as mandated by the Sarbanes-Oxley Act of 2002.

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

FORM 10-K

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

For the fiscal year ended **December 31, 2009**
Commission file number **1-10447**

CABOT OIL & GAS CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**04-3072771**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification Number)

Three Memorial City Plaza
840 Gessner Road, Suite 1400
Houston, Texas 77024
(Address of principal executive offices including ZIP code)

(281) 589-4600
(Registrant's telephone number, including area code)

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 $.10 per share	**New York Stock Exchange**

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 _X_ No ____

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 _X_

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

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes _X_ No ____

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

(continued)

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer _X_ Accelerated filer __

Non-accelerated filer __ Smaller reporting company __
(Do not check if a smaller reporting company)

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

The aggregate market value of Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates as of the last business day of registrant's most recently completed second fiscal quarter (based upon the closing sales price on the New York Stock Exchange on June 30, 2009) was approximately $3.2 billion.

As of February 22, 2010, there were 103,821,454 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 27, 2010 are incorporated by reference into Part III of this report.

TABLE OF CONTENTS

The statements regarding future financial and operating performance and results, strategic pursuits and goals, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. These statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results of future drilling and marketing activity, future production and costs, legislative and regulatory initiatives and other factors detailed in this document and in our other Securities and Exchange Commission filings. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this document. See "Forward-Looking Information" for further details.

CERTAIN DEFINITIONS

The following is a list of commonly used terms and their definitions included within this Annual Report on Form 10-K:

Abbreviated Term	Definition
Mcf	Thousand cubic feet
Mmcf	Million cubic feet
Bcf	Billion cubic feet
Bbl	Barrel
Mbbls	Thousand barrels
Mcfe	Thousand cubic feet of natural gas equivalents
Mmcfe	Million cubic feet of natural gas equivalents
Bcfe	Billion cubic feet of natural gas equivalents
Mmbtu	Million British thermal units
NGL	Natural gas liquids

PART I

ITEM 1. BUSINESS

OVERVIEW

Cabot Oil & Gas Corporation is an independent oil and gas company engaged in the development, exploitation and exploration of oil and gas properties located in North America. In 2009, we restructured our operations by combining our Rocky Mountain and Appalachian areas to form the North Region and combining the Anadarko Basin with our Texas and Louisiana areas to form the South Region. Certain prior period amounts and historical descriptions have been reclassified to reflect this reorganization. Operationally, we now have two primary regional offices located in Houston, Texas and Pittsburgh, Pennsylvania.

In 2009, energy commodity prices recovered from the price levels experienced during the second half of 2008. Our 2009 average realized natural gas price was $7.47 per Mcf, 11% lower than the 2008 average realized price of $8.39 per Mcf. Our 2009 average realized crude oil price was $85.52 per Bbl, 4% lower than the 2008 average realized price of $89.11 per Bbl. These realized prices include realized gains and losses resulting from commodity derivatives (zero-cost collars or swaps). For information about the impact of these derivatives on realized prices, refer to the "Results of Operations" section in Item 7 of this Annual Report on Form 10-K.

In 2009, our investment program totaled $640.4 million, including lease acquisition ($145.7 million) and drilling and facilities ($401.1 million) programs. Our capital spending was funded largely through cash flow from operations and, to a lesser extent, borrowings on our revolving credit facility.

We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and will continue to add shareholder value over the long-term.

In April 2009, we sold substantially all of our Canadian properties to a private Canadian company (see Note 2 of the Notes to the Consolidated Financial Statements for further details). In April 2009, we also entered into a new revolving credit facility and terminated our prior credit facility (see Note 4 of the Notes to the Consolidated Financial Statements for further details).

In August 2008, we completed the acquisition of producing properties, leasehold acreage and a natural gas gathering infrastructure in east Texas (the "east Texas acquisition"). We paid total net cash consideration of approximately $604.0 million (see Note 2 of the Notes to the Consolidated Financial Statements for further details). In order to finance the east Texas acquisition, we completed a public offering of 5,002,500 shares of our common stock in June 2008, receiving net proceeds of $313.5 million (see Note 9 of the Notes to the Consolidated Financial Statements for further details), and we closed a private placement in July 2008 of $425 million principal amount of senior unsecured fixed rate notes (see Note 4 of the Notes to the Consolidated Financial Statements for further details).

On an equivalent basis, our production level in 2009 increased by 8% from 2008. We produced 103.0 Bcfe, or 282.1 Mmcfe per day, in 2009, as compared to 95.2 Bcfe, or 260.1 Mmcfe per day, in 2008. Natural gas production increased to 97.9 Bcf in 2009 from 90.4 Bcf in 2008, primarily due to increased production in the North region associated with the increased drilling program in Susquehanna County, Pennsylvania as well as increased natural gas production in the South region associated with the properties we acquired in the east Texas acquisition in August 2008 and drilling in the Angie field in east Texas. Partially offsetting these production gains were decreases in production in Canada due to the sale of our Canadian properties in April 2009, as well as reduced drilling activity in Oklahoma and Wyoming. Oil production increased by 36 Mbbls from 782 Mbbls in 2008 to 818 Mbbls in 2009 due primarily to increased production in the South region associated with the properties we acquired in the east Texas acquisition in August 2008 and an increase related to Pettet development in the Angie field, partially offset by a decrease in production in Canada due to the sale of our Canadian properties in April 2009.

For the year ended December 31, 2009, we drilled 143 gross wells (119 net) with a success rate of 95% compared to 432 gross wells (355 net) with a success rate of 97% for the prior year. In 2010, we plan to drill approximately 136 gross wells (123.9 net), focusing our capital program in the Marcellus Shale in northeast Pennsylvania and, to a lesser extent, in east Texas.

Our 2009 total capital and exploration spending was $640.4 million compared to $1.5 billion of total capital and exploration spending in 2008. In both 2009 and 2008, we allocated our planned program for capital and exploration expenditures among our various operating regions based on return expectations, availability of services and human resources. We plan to continue such method of allocation in 2010. Funding of the program is expected to be provided by operating cash flow, existing cash and increased borrowings under our credit facility, if required. For 2010, the North region is expected to receive approximately 69% of the anticipated capital program, with the remaining 31% dedicated to the South region. In 2010, we plan to spend approximately $585 million on capital and exploration activities.

Our proved reserves totaled approximately 2,060 Bcfe at December 31, 2009, of which 98% were natural gas. This reserve level was up by 6% from 1,942 Bcfe at December 31, 2008 on the strength of results from our drilling program. In 2009, we had a net downward revision of 200.1 Bcfe primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the Securities and Exchange Commission's (SEC) new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions.

The following table presents certain reserve, production and well information as of December 31, 2009.

	North	South	**Total**
Proved Reserves at Year End *(Bcfe)*			
Developed..	850.0	474.7	**1,324.7**
Undeveloped..	496.1	239.1	**735.2**
Total..	1,346.1	713.8	**2,059.9**
Average Daily Production *(Mmcfe per day)*	136.6	145.5	**282.1**
Reserve Life Index *(In years)* (1)	27.0	13.4	**20.0**
Gross Wells..	4,141	1,753	**5,894**
Net Wells (2)	3,536.9	1,230.2	**4,767.1**
Percent Wells Operated *(Gross)*	88.9%	76.6%	**85.2%**

(1) *Reserve Life Index is equal to year-end reserves divided by annual production.*

(2) *The term "net" as used in "net acreage" or "net production" throughout this document refers to amounts that include only acreage or production that is owned by us and produced to our interest, less royalties and production due others. "Net wells" represents our working interest share of each well.*

Our interest in both developed and undeveloped properties is primarily in the form of leasehold interests held under customary mineral leases. These leases provide us the right, in general, to develop oil and/or natural gas on the properties. Their primary terms range in length from approximately three to ten years. These properties are held for longer periods if production is established. We own leasehold rights on approximately 2.9 million gross acres. In addition, we own fee interest in approximately 0.2 million gross acres, primarily in West Virginia. Our two largest fields, Brachfield Southeast in east Texas and Dimock in Susquehanna County, Pennsylvania, each contain more than 15% of our proved reserves. In addition, we are focusing significant drilling and production activity in the Angie field area of east Texas. These three fields combined make up approximately 43% of our proved reserves.

The following table presents certain information with respect to our principal properties as of and for the year ended December 31, 2009.

	Production Volumes						Nature of	Average Sales Price (1)		Average
	Natural Gas (Mcf/Day)	Oil and NGLs (Bbls/Day)	Total (Mcfe/Day)	Proved Reserves (Mmcfe)	Gross Producing Wells	Gross Wells Drilled	Interest (Working / Royalty)	Natural Gas (Mcf)	Oil and NGLs (Bbl)	Production Cost (Mcfe)
Pensylvania										
Dimock (Susquehanna area)................	36,227	-	36,227	458,991	73	51	W	$ 4.27	$ -	$ 0.03
East Texas										
Brachfield Southeast (Minden area)....	35,981	462	38,753	320,835	200	17	W	$ 4.13	$ 51.82	$ 0.65
Angie (County Line area)....................	35,904	387	38,226	98,168	86	36	W	$ 3.40	$ 66.47	$ 0.27

(1) *Excludes the impact of realized derivative instrument settlements.*

NORTH REGION

The North region is comprised of the Appalachian and Rocky Mountains areas. In April 2009, we sold substantially all of our Canadian properties to a private Canadian company. Our activities in the Appalachian area are concentrated primarily in northeast Pennsylvania and in West Virginia. Our activities in the Rocky Mountains area are concentrated in the Green River and Washakie Basins in Wyoming and the Paradox Basin in Colorado. This region is managed from our office in Pittsburgh, Pennsylvania. In this region, our assets include a large acreage position, a high concentration of wells, natural gas gathering and pipeline systems, and storage capacity.

Capital and exploration expenditures for 2009 were $380.3 million, or 60% of our total 2009 capital and exploration expenditures, compared to $483.7 million for 2008, or 32% of our total 2008 capital and exploration expenditures. This decrease in spending was substantially driven by a $69.5 million decrease in drilling and facilities costs year-over-year and the sale of our Canadian properties in April 2009. For 2010, we have budgeted approximately $402 million for capital and exploration expenditures in the region.

At December 31, 2009, we had 4,141 wells (3,536.9 net), of which 3,681wells are operated by us. There are multiple producing intervals in the Appalachian area that include the Big Lime, Weir, Berea and Devonian (including Marcellus) Shale formations at depths primarily ranging from 950 to 9,080 feet, with an average depth of approximately 3,950 feet. In the Rocky Mountains area, principal producing intervals are in the Almond, Frontier, Dakota and Honaker Trail formations at depths ranging from 4,200 to 14,375 feet, with an average depth of approximately 10,950 feet. Average net daily production in 2009 for the North region was 136.6 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2009 was 49.2 Bcf and 125 Mbbls, respectively.

While natural gas production volumes from North region reservoirs are on balance lower on a per-well basis compared to other areas of the United States, the productive life of North region reserves is relatively long. At December 31, 2009, we had 1,346.1 Bcfe of proved reserves (substantially all natural gas) in the North region, constituting 65% of our total proved reserves. Developed and undeveloped reserves made up 850.0 Bcfe and 496.1 Bcfe of the total proved reserves for the North region, respectively.

In 2009, we drilled 62 wells (59.4 net) in the North region, of which 61 wells (59.3 net) were development and extension wells. In 2010, we plan to drill approximately 100 wells (100 net), primarily in the Dimock field in northern Pennsylvania.

In 2009, we produced and marketed approximately 321 barrels of crude oil/condensate/NGL per day in the North region at market responsive prices.

Ancillary to our exploration, development and production operations, we operated a number of gas gathering and transmission pipeline systems, made up of approximately 3,165 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2009. The majority of our pipeline infrastructure in West Virginia is regulated by the Federal Energy Regulatory Commission (FERC) for interstate transportation service and the West Virginia Public Service Commission (WVPSC) for intrastate transportation service. As such, the transportation rates and terms of service of our pipeline subsidiary, Cranberry Pipeline Corporation, are subject to the rules and regulations of the FERC and the WVPSC. Our natural gas gathering and transmission pipeline systems enable us to connect new wells quickly and to transport natural gas from the wellhead directly to interstate pipelines, local distribution companies and industrial end users. Control of our gathering and transmission pipeline systems also enables us to purchase, transport and sell natural gas produced by third parties. In addition, we can engage in development drilling without relying upon third parties to transport our natural gas and incur only the incremental costs of pipeline and compressor additions to our system.

We have two natural gas storage fields located in West Virginia with a combined working capacity of approximately 4 Bcf. We use these storage fields to take advantage of the seasonal variations in the demand for natural gas and the higher prices typically associated with winter natural gas sales, while maintaining production at a nearly constant rate throughout the year. The storage fields also enable us to increase for shorter intervals of time the volume of natural gas that we can deliver by more than 40% above the volume that we could deliver solely from our production in the North region. The pipeline systems and storage fields are fully integrated with our operations.

The principal markets for our North region natural gas are in the northeastern and northwestern United States. We sell natural gas to industrial customers, local distribution companies and gas marketers both on and off our pipeline and gathering system. Approximately 61% of our natural gas sales volume in the North region is sold at index-based prices under contracts with terms of one to three years. In addition, spot market sales are made at index-based prices under month-to-month contracts, while industrial and utility sales generally are made under year-to-year contracts. Approximately one percent of North region production is sold on fixed price contracts that typically renew annually.

SOUTH REGION

Our development, exploitation, exploration and production activities in the South region are primarily concentrated in east and south Texas, Oklahoma and north Louisiana. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley, Haynesville, Pettit and James Lime formations in north Louisiana and east Texas, the Frio, Vicksburg and Wilcox formations in south Texas and the Chase, Morrow and Chester formations in the Anadarko Basin in Oklahoma at depths ranging from 1,300 to 16,970 feet, with an average depth of approximately 8,750 feet.

Capital and exploration expenditures were $237.6 million for 2009, or 37% of our total 2009 capital and exploration expenditures, compared to $1,022.3 million for 2008, or 68% of our total 2008 capital and exploration expenditures. This decrease in capital spending is primarily due to $604.0 million paid in 2008 for the east Texas acquisition and a decrease of $176.9 million in total drilling. Of the total company year-over-year decrease in capital and exploration expenditures, approximately 93% was attributable to the decrease in the South region spending. For 2010, we have budgeted approximately $181 million for capital and exploration expenditures in the region. Our 2010 South region drilling program will emphasize activity primarily in east Texas.

We had 1,753 wells (1,230.2 net) in the South region as of December 31, 2009, of which 1,342 wells are operated by us. Average daily production in 2009 was 145.5 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2009 was 48.8 Bcf and 720 Mbbls, respectively.

At December 31, 2009, we had 713.8 Bcfe of proved reserves (95% natural gas) in the South region, which represented 35% of our total proved reserves. Developed and undeveloped reserves made up 474.7 Bcfe and 239.1 Bcfe of the total proved reserves for the South region, respectively.

In 2009, we drilled 81 wells (59.2 net) in the South region, of which 75 wells (55.3 net) were development and extension wells. In 2010, we plan to drill 36 wells (24 net), primarily in east Texas, including the Minden and Angie fields.

Our principal markets for the South region natural gas are in the industrialized Gulf Coast area and the Midwestern United States. We sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Currently, approximately 89% of our natural gas sales volumes in the South region are sold at index-based prices under contracts with terms of one year or greater. The remaining 11% of our sales volumes are sold at index-based prices under short-term agreements. The South region properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

In 2009, we produced and marketed approximately 1,966 barrels of crude oil/condensate/NGL per day in the South region at market responsive prices.

RISK MANAGEMENT

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. While there are many different types of derivatives available, in 2009 we employed natural gas and crude oil price collar and swap agreements for portions of our 2009 through 2010 production to attempt to manage price risk more effectively. In addition, we entered into natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting. In 2008 and 2007, we employed price collars and swaps to hedge our price exposure on our production. The collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place.

For 2009, collars covered 48% of natural gas production and had a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. For 2009, swaps covered 16% of natural gas production and 45% of crude oil production and had a weighted-average price of $12.18 per Mcf and $125.25 per Bbl, respectively.

As of December 31, 2009, we had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price		Volume		Contract Period
Derivatives designated as Hedging Instruments under ASC 815						
Natural Gas	Swap	$9.30	per Mcf	35,856	Mmcf	2010
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010
Derivatives not qualifying as Hedging Instruments under ASC 815						
Natural Gas	Basis Swap	$(0.27)	per Mcf	16,123	Mmcf	2012

Our decision to hedge 2010 and 2012 production fits with our risk management strategy and allows us to lock in the benefit of high commodity prices on a portion of our anticipated production.

We will continue to evaluate the benefit of employing derivatives in the future. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Quantitative and Qualitative Disclosures about Market Risk” for further discussion concerning our use of derivatives.

RESERVES

Current Reserves

The following table presents our estimated proved reserves at December 31, 2009.

	Natural Gas *(Mmcf)*	Liquids [1] *(Mbbl)*	Total [2] [3] *(Mmcfe)*
Developed:			
North............................	842,180	1,296	849,955
South............................	445,989	4,786	474,708
Undeveloped:			
North............................	495,276	137	496,097
South............................	229,717	1,564	239,098
Total............................	**2,013,162**	**7,783**	**2,059,858**

(1) *Liquids include crude oil, condensate and natural gas liquids.*

(2) *Natural gas equivalents are determined using the ratio of 6 Mcf of natural gas to 1Bbl of crude oil, condensate or natural gas liquids.*

(3) *Total proved reserves includes undeveloped reserves that were originally booked more than five years prior to December 31, 2009 that have not yet been developed due to (a) coal mining operations, consisting of 7,972 Mmcfe and 6,057 Mmcfe of reserves booked in 2003 and 2004, respectively, and (b) delays associated with an environmental impact statement required to drill on federal land in Wyoming, consisting of 1,362 Mmcfe and 506 Mmcfe of reserves booked in 1997 and 2001, respectively.*

The proved reserve estimates presented here were prepared by our petroleum engineering staff and reviewed by Miller and Lents, Ltd., independent petroleum engineers. Miller and Lents made independent estimates for 100% of the proved reserves estimated by us and concluded the following: In their judgment we have an effective system for gathering data and documenting information required to estimate our proved reserves and project our future revenues; we used appropriate engineering, geologic and evaluation principles and techniques in accordance with practices generally accepted in the petroleum industry in making our estimates and projections and our total proved reserves are reasonable. For additional information regarding estimates of proved reserves, the review of such estimates by Miller and Lents, Ltd., and other information about our oil and gas reserves, see the Supplemental Oil and Gas Information to the Consolidated Financial Statements included in Item 8. A copy of the review letter by Miller and Lents, Ltd., dated February 12, 2010, has been filed as an exhibit to this Form 10-K. Our reserves are sensitive to natural gas and crude oil sales prices and their effect on the economic productive life of producing properties. Our reserves are based on 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during 2009. Increases in commodity prices may result in a longer economic productive life of a property or result in more economically viable proved undeveloped reserves to be recognized. Decreases in prices may result in negative impacts of this nature.

Internal Control

Our corporate reservoir engineers report to the Director of Engineering, who maintains oversight and compliance responsibility for the internal reserve estimate process and provides oversight for the annual review of 100% our year-end reserves by our independent third party engineers, Miller and Lents, Ltd. The management of our corporate reservoir engineering group consists of three petroleum/chemical engineers, with petroleum/chemical engineering degrees and between 10 and 27 years of industry experience, between 3 and 27 years of reservoir engineering/management experience, and between 0.5 and 11 years managing our reserves. All are members of the Society of Petroleum Engineers.

Qualifications of Third Party Engineers

The technical person primarily responsible for review of our reserve estimates at Miller and Lents, Ltd. meets the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Miller and Lents, Ltd. is an independent firm of petroleum engineers, geologists, geophysicists, and petro physicists; they do not own an interest in our properties and are not employed on a contingent fee basis.

For additional information about the risks inherent in our estimates of proved reserves, see "Risk Factors—Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated" in Item 1A.

Proved Undeveloped Reserves

At December 31, 2009, we had 735.2 Bcfe of proved undeveloped reserves. During 2009, we converted 70.7 Bcfe of reserves from proved undeveloped to proved developed. An additional 9.6 Bcfe of reserves associated with seven wells drilled in 2009 remain proved undeveloped as a result of the additional capital required to complete the wells. During 2009, total capital related to the development of proved undeveloped reserves was $102.6 million. We had a downward revision of total proved reserves of 200.1 Bcfe primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC's new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions. In accordance with the new rules we priced proved oil and gas reserves using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month within the 12-month period prior to the end of the reporting period.

As of December 31, 2009 we have 15.9 Bcfe of proved undeveloped reserves, representing less than 1% of our total proved reserves, that will require more than five years to develop due to coal mining operations or delays associated with an environment impact statement required to drill on federal land in Wyoming. An environmental impact study on federal land represents 1.9 Bcfe and the following table summarizes the reserves impacted by mining operations in West Virginia.

Restriction	Year Reserves First Recorded	Net Bcfe	Location
Mining	2003	7.97	West Virginia
Mining	2004	6.06	West Virginia
		14.03	

Historical Reserves

The following table presents our estimated proved reserves for the periods indicated.

	Natural Gas	Oil & Liquids	Total
	(Mmcf)	*(Mbbl)*	*(Mmcfe)* [1]
December 31, 2006 [4]	1,368,293	7,973	1,416,129
Revision of Prior Estimates..............................	2,604	771	7,228
Extensions, Discoveries and			
Other Additions...	265,830	1,381	274,114
Production..	(80,475)	(830)	(85,451)
Purchases of Reserves in Place.........................	3,701	33	3,899
Sales of Reserves in Place................................	-	-	-
December 31, 2007 [4]	1,559,953	9,328	1,615,919
Revision of Prior Estimates [2]	(47,745)	(1,593)	(57,302)
Extensions, Discoveries and			
Other Additions...	297,089	1,134	303,895
Production..	(90,425)	(794)	(95,191)
Purchases of Reserves in Place.........................	167,262	1,268	174,872
Sales of Reserves in Place................................	(141)	(2)	(156)
December 31, 2008 [4]	1,885,993	9,341	1,942,037
Revision of Prior Estimates [3]	(193,767)	(1,062)	(200,143)
Extensions, Discoveries and			
Other Additions...	459,612	544	462,880
Production..	(97,914)	(844)	(102,976)
Purchases of Reserves in Place.........................	9	-	9
Sales of Reserves in Place................................	(40,771)	(196)	(41,949)
December 31, 2009...	**2,013,162**	**7,783**	**2,059,858**
Proved Developed Reserves			
December 31, 2006..	996,850	5,895	1,032,222
December 31, 2007..	1,133,937	7,026	1,176,091
December 31, 2008..	1,308,155	6,728	1,348,521
December 31, 2009..	**1,288,169**	**6,082**	**1,324,663**

(1) *Includes natural gas and natural gas equivalents determined by using the ratio of 6 Mcf of natural gas to 1 Bbl of crude oil, condensate or natural gas liquids.*

(2) *The majority of the revisions were the result of the decrease in the natural gas price.*

(3) *The net downward revision of 200.1 Bcfe was primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC's new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions.*

(4) *Prior to 2009, reserve estimates were based on year end prices.*

Volumes and Prices: Production Costs

The following table presents regional historical information about our net wellhead sales volume for natural gas and crude oil (including condensate and natural gas liquids), produced natural gas and crude oil realized sales prices, and production costs per equivalent.

	Year Ended December 31,		
Net Wellhead Sales Volume	**2009**	2008	2007
Natural Gas *(Bcf)*			
North	**48.2**	39.7	38.8
South	**48.8**	46.6	37.8
Canada	**1.0**	4.1	3.9
Crude/Condensate/Ngl *(Mbbl)*			
North	**118**	118	140
South	**720**	655	672
Canada	**7**	21	18
Equivalents *(Bcfe)*			
North	**48.9**	40.4	39.7
South	**53.1**	50.5	41.8
Canada	**1.0**	4.3	4.0
Produced Natural Gas Sales Price *($/Mcf)* [1]			
North	**$ 6.59**	$ 7.95	$ 7.02
South	**8.42**	8.84	7.63
Canada	**3.72**	7.62	5.47
Weighted-Average	**7.47**	8.39	7.23
Produced Crude/Condensate Sales Price *($/Bbl)* [1]			
North	**$ 54.11**	$ 93.62	$ 67.37
South	**90.86**	88.46	67.30
Canada	**33.97**	85.08	59.96
Weighted-Average	**85.52**	89.11	67.16
Production Costs *($/Mcfe)* [2]			
North	**$ 0.67**	$ 0.80	$ 0.66
South	**0.78**	0.76	0.78
Canada	**1.55**	0.88	0.84
Weighted-Average	**0.74**	0.78	0.73

(1) *Represents the average realized sales price for all production volumes and royalty volumes sold during the periods shown, net of related costs (principally purchased gas royalty, transportation and storage). Includes realized impact of derivative instruments.*

(2) *Production costs include direct lifting costs (labor, repairs and maintenance, materials and supplies), the costs of administration of production offices and insurance, but is exclusive of depreciation and depletion applicable to capitalized lease acquisition, exploration and development expenditures and taxes other than income.*

Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2009. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Leasehold Acreage by State						
Alabama	-	-	197	197	197	197
Arkansas	1,981	425	-	-	1,981	425
Colorado	17,640	14,567	152,872	106,396	170,512	120,963
Kansas	28,827	27,505	-	-	28,827	27,505
Louisiana	8,318	5,852	7,464	5,574	15,782	11,426
Maryland	-	-	1,662	1,662	1,662	1,662
Mississippi	-	-	354,203	235,812	354,203	235,812
Montana	397	210	199,391	135,791	199,788	136,001
Nevada	-	-	65,260	65,260	65,260	65,260
New York	2,379	961	5,178	4,943	7,557	5,904
North Dakota	-	-	25,937	9,706	25,937	9,706
Ohio	6,246	2,384	2,403	1,214	8,649	3,598
Oklahoma	198,639	141,303	54,022	35,702	252,661	177,005
Pennsylvania	118,254	70,177	183,110	182,655	301,364	252,832
Texas	147,574	112,800	121,261	86,939	268,835	199,739
Utah	2,820	1,609	149,735	77,468	152,555	79,077
Virginia	7,130	5,136	2,703	1,649	9,833	6,785
West Virginia	589,988	561,961	205,437	176,175	795,425	738,136
Wyoming	139,509	71,695	112,713	61,981	252,222	133,676
Total	**1,269,702**	**1,016,585**	**1,643,548**	**1,189,124**	**2,913,250**	**2,205,709**
Mineral Fee Acreage by State						
Colorado	-	-	2,899	271	2,899	271
Kansas	160	128	-	-	160	128
Montana	-	-	589	75	589	75
New York	-	-	6,545	1,353	6,545	1,353
Oklahoma	16,580	13,979	730	179	17,310	14,158
Pennsylvania	524	524	1,573	502	2,097	1,026
Texas	207	135	1,012	511	1,219	646
Virginia	17,817	17,817	100	34	17,917	17,851
West Virginia	97,215	78,543	50,896	49,669	148,111	128,212
Total	**132,503**	**111,126**	**64,344**	**52,594**	**196,847**	**163,720**
Aggregate Total	**1,402,205**	**1,127,711**	**1,707,892**	**1,241,718**	**3,110,097**	**2,369,429**

Total Net Leasehold Acreage by Region of Operation

	Developed	Undeveloped	Total
North	728,700	824,900	1,553,600
South	287,885	364,224	652,109
Total	**1,016,585**	**1,189,124**	**2,205,709**

Total Net Undeveloped Acreage Expiration by Region of Operation

The following table presents our net undeveloped acreage expiring over the next three years by operating region as of December 31, 2009. The figures below assume no future successful development or renewal of undeveloped acreage.

	2010	2011	2012
North....................	176,610	153,650	162,785
South....................	203,403	91,710	14,871
Total....................	**380,013**	**245,360**	**177,656**

Well Summary

The following table presents our ownership at December 31, 2009, in productive natural gas and oil wells in the North region (consisting primarily of various fields located in West Virginia, Pennsylvania, Colorado, Utah and Wyoming) and in the South region (consisting primarily of various fields located in Louisiana, Texas, Oklahoma and Kansas) . This summary includes natural gas and oil wells in which we have a working interest.

	Natural Gas		Oil		Total [(1)]	
	Gross	Net	Gross	Net	Gross	Net
North..................	4,104	3,517.8	37	19.1	4,141	3,536.9
South..................	1,588	1,093.3	165	136.9	1,753	1,230.2
Total..................	**5,692**	**4,611.1**	**202**	**156.0**	**5,894**	**4,767.1**

(1) *Total does not include service wells of 55 (52.6 net).*

Drilling Activity

We drilled wells, participated in the drilling of wells, or acquired wells as indicated in the region tables below.

	Year Ended December 31, 2009 (1)					
	North		South		**Total**	
	Gross	Net	Gross	Net	**Gross**	**Net**
Development Wells						
Productive.........	53	51.3	71	52.3	124	103.6
Dry....................	1	1.0	4	3.0	5	4.0
Extension Wells						
Productive.........	7	7.0	-	-	7	7.0
Dry....................	-	-	-	-	-	-
Exploratory Wells						
Productive.........	1	0.1	4	2.4	5	2.5
Dry....................	-	-	2	1.5	2	1.5
Total.........	**62**	**59.4**	**81**	**59.2**	**143**	**118.6**
Wells Acquired.......	-	-	1	1.0	1	1.0
Wells in Progress at End of Year...	10	10.0	6	4.0	16	14.0

(1) *In April 2009, we sold substantially all of our Canadian properties.*

	Year Ended December 31, 2008							
	North		South		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive.........	250	227.2	145	99.7	3	2.0	398	328.9
Dry....................	1	1.0	7	6.3	1	0.6	9	7.9
Extension Wells								
Productive.........	3	3.0	2	1.7	-	-	5	4.7
Dry....................	1	1.0	-	-	-	-	1	1.0
Exploratory Wells								
Productive.........	3	3.0	11	6.8	2	0.8	16	10.6
Dry....................	3	1.5	-	-	-	-	3	1.5
Total.........	**261**	**236.7**	**165**	**114.5**	**6**	**3.4**	**432**	**354.6**
Wells Acquired..........	-	-	70	68.3	-	-	70	68.3
Wells in Progress at End of Year...	7	6.3	8	5.0	-	-	15	11.3

	Year Ended December 31, 2007							
	North		South		Canada		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells								
Productive.........	295	263.8	129	99.1	5	2.8	429	365.7
Dry....................	1	1.0	10	8.3	-	-	11	9.3
Extension Wells								
Productive.........	1	1.0	4	3.0	3	1.2	8	5.2
Dry....................	-	-	-	-	-	-	-	-
Exploratory Wells								
Productive.........	3	2.8	1	0.5	2	1.2	6	4.5
Dry....................	3	2.2	4	4.0	-	-	7	6.2
Total.........	**303**	**270.8**	**148**	**114.9**	**10**	**5.2**	**461**	**390.9**
Wells Acquired..........	-	-	2	1.9	-	-	2	1.9
Wells in Progress at End of Year...	2	2.0	11	6.3	1	0.2	14	8.5

Competition

Competition in our primary producing areas is intense. Price, contract terms and quality of service, including pipeline connection times and distribution efficiencies, affect competition. We believe that in the North region our extensive acreage position, existing natural gas gathering and pipeline systems, services and equipment that we have secured for the upcoming year and storage fields enhance our competitive position over other producers who do not have similar systems or facilities in place. We also actively compete against other companies with substantially larger financial and other resources.

OTHER BUSINESS MATTERS

Major Customer

In 2009, two customers accounted for approximately 13% and 11%, respectively, of the Company's total sales. In 2008, one customer accounted for approximately 16% of the Company's total sales. In 2007, no customer accounted for more than 10% of the Company's total sales.

Seasonality

Demand for natural gas has historically been seasonal, with peak demand and typically higher prices occurring during the colder winter months.

Regulation of Oil and Natural Gas Exploration and Production

Exploration and production operations are subject to various types of regulation at the federal, state and local levels. This regulation includes requiring permits to drill wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties on which wells are drilled, and the plugging and abandoning of wells. 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 that may be drilled in a given field, and the unitization or pooling of oil and natural gas properties. Some states allow the forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibiting the venting or flaring of natural gas and imposing certain requirements regarding the ratability of production. The effect of these regulations is to limit the amounts of oil and natural gas we can produce from our wells, and to limit the number of wells or the locations where we can drill. Because these statutes, rules and regulations undergo constant review and often are amended, expanded and reinterpreted, we are unable to predict the future cost or impact of regulatory compliance. The regulatory burden on the oil and gas industry increases its cost of doing business and, consequently, affects its profitability. We do not believe, however, we are affected differently by these regulations than others in the industry.

Natural Gas Marketing, Gathering and Transportation

Federal legislation and regulatory controls have historically affected the price of the natural gas we produce and the manner in which our production is transported and marketed. Under the Natural Gas Act of 1938 (NGA), the FERC regulates the interstate sale for resale of natural gas and the transportation of natural gas in interstate commerce, although facilities used in the production or gathering of natural gas in interstate commerce are generally exempted from FERC jurisdiction. Effective January 1, 1993, the Natural Gas Wellhead Decontrol Act deregulated natural gas prices for all "first sales" of natural gas, which definition covers all sales of our own production. In addition, as part of the broad industry restructuring initiatives described below, the FERC has granted to all producers such as us a "blanket certificate of public convenience and necessity" authorizing the sale of gas for resale without further FERC approvals. As a result, all of our produced natural gas may now be sold at market prices, subject to the terms of any private contracts that may be in effect. In addition, under the provisions of the Energy Policy Act of 2005 (2005 Act), the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. Pursuant to the 2005 Act, the FERC established new regulations that are intended to increase natural gas pricing transparency through, among other things, requiring market participants to report their gas sales transactions annually to the FERC, and new regulations that require certain non-interstate pipelines to post daily scheduled volume information and design capacity for certain points on their systems. The 2005 Act also significantly increased the penalties for violations of the NGA and the FERC's regulations.

Our natural gas sales prices nevertheless continue to be affected by intrastate and interstate gas transportation regulation, because the prices we receive for our production are affected by the cost of transporting the gas to the consuming market. Through a series of comprehensive rulemakings, beginning with Order No. 436 in 1985 and continuing through Order No. 636 in 1992 and Order No. 637 in 2000, the FERC has adopted regulatory changes that have significantly altered the transportation and marketing of natural gas. These changes were intended by the FERC to foster competition by, among other things, transforming the role of interstate pipeline companies from wholesale marketers of gas to the primary role of gas transporters, and by increasing the transparency of pricing for pipeline services. The FERC has also established regulations governing the relationship of pipelines with their marketing affiliates, which essentially require that designated employees function independently of each other, and that certain information not be shared. The FERC has also implemented standards relating to the use of electronic data exchange by the pipelines to make transportation information available on a timely basis and to enable transactions to occur on a purely electronic basis.

In light of these statutory and regulatory changes, most pipelines have divested their gas sales functions to marketing affiliates, which operate separately from the transporter and in direct competition with all other merchants, and most pipelines have also implemented the large-scale divestiture of their gas gathering facilities to affiliated or non-affiliated companies. Interstate pipelines thus now generally provide unbundled, open and nondiscriminatory transportation and transportation-related services to producers, gas marketing companies, local distribution companies, industrial end users and other customers seeking such services. Sellers and buyers of gas have gained direct access to the particular pipeline services they need, and are better able to conduct business with a larger number of counterparties. We believe these changes generally have improved our access to markets while, at the same time, substantially increasing competition in the natural gas marketplace.

Certain of our pipeline systems and storage fields in West Virginia are regulated for safety compliance by the U.S. Department of Transportation (DOT) and the West Virginia Public Service Commission. In 2002, Congress enacted the Pipeline Safety Improvement Act of 2002 (2002 Act), which contains a number of provisions intended to increase pipeline operating safety. The DOT's final regulations implementing the act became effective February 2004. Among other provisions, the regulations require that pipeline operators implement a pipeline integrity management program that must at a minimum include an inspection of gas transmission and non-rural gathering pipeline facilities within the next ten years, and at least every seven years thereafter. On March 15, 2006, the DOT revised these regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non-rural areas, and adopt new compliance deadlines. We have completed 100% of the required initial inspection (baseline assessment) of our pipeline systems in West Virginia. In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, which reauthorized the programs adopted under the 2002 Act, proposed enhancements for state programs to reduce excavation damage to pipelines, established increased federal enforcement of one-call excavation programs, and established a new program for review of pipeline security plans and critical facility inspections. In July 2009, DOT issued a Notice of Proposed Rulemaking to update its reporting requirements for natural gas and hazardous liquid pipelines. On December 3, 2009, DOT adopted a regulation requiring gas and hazardous liquid pipelines that use supervisory control and data acquisition (SCADA) systems and have at least one controller and control room to develop written control room management procedures by August 1, 2011 and implement the procedures by February 1, 2012.

We cannot predict what new or different regulations the FERC and other regulatory agencies may adopt, or what effect subsequent regulations may have on our activities. Similarly, it is impossible to predict what proposals, if any, that affect the oil and natural gas industry might actually be enacted by Congress or the various state legislatures and what effect, if any, such proposals might have on us. Similarly, and despite the recent trend toward federal deregulation of the natural gas industry, whether or to what extent that trend will continue, or what the ultimate effect will be on our sales of gas, cannot be predicted.

Federal Regulation of Petroleum

Our sales of oil and natural gas liquids are not regulated and are at market prices. The price received from the sale of these products is affected by the cost of transporting the products to market. Much of that transportation is through interstate common carrier pipelines. Effective January 1, 1995, the FERC implemented regulations generally grandfathering all previously approved interstate transportation rates and establishing an indexing system for those rates by which adjustments are made annually based on the rate of inflation, subject to certain conditions and limitations. These regulations may tend to increase the cost of transporting oil and natural gas liquids by interstate pipeline, although the annual adjustments may result in decreased rates in a given year. Every five years, the FERC must examine the relationship between the annual change in the applicable index and the actual cost changes experienced in the oil pipeline industry. In March 2006, to implement this required five-year re-determination, the FERC established an upward adjustment in the index to track oil pipeline cost changes and determined that the Producer Price Index for Finished Goods plus 1.3 percent should be the oil pricing index for the five-year period beginning July 1, 2006. Another FERC matter that may impact our transportation costs relates to a recent policy that allows a pipeline structured as a master limited partnership or similar non-corporate entity to include in its rates a tax allowance with respect to income for which there is an "actual or potential income tax liability," to be determined on a case by case basis. Generally speaking, where the holder of a partnership unit interest is required to file a tax return that includes partnership income or loss, such unit-holder is presumed to have an actual or potential income tax liability sufficient to support a tax allowance on that partnership income. We currently do not transport any of our oil or natural gas liquids on a pipeline structured as a master limited partnership.

We are not able to predict with certainty the effect upon us of these periodic reviews by the FERC of the pipeline index, or of the application of the FERC's policy on income tax allowances.

Environmental Regulations

General. Our operations are subject to extensive federal, state and local laws and regulations relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. Permits are required for the operation of our various facilities. These permits can be revoked, modified or renewed by issuing authorities. Governmental authorities enforce compliance with their regulations through fines, injunctions or both. Government regulations can increase the cost of planning, designing, installing and operating, and can affect the timing of installing and operating, oil and gas facilities. Although we believe that compliance with environmental regulations will not have a material adverse effect on us, risks of substantial costs and liabilities related to environmental compliance issues are part of oil and gas production operations. No assurance can be given that significant costs and liabilities will not be incurred. Also, it is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from oil and gas production could result in substantial costs and liabilities to us.

The transition zone and shallow-water areas of the U.S. Gulf Coast are ecologically sensitive. Environmental issues have led to higher drilling costs and a more difficult and lengthy well permitting process. U.S. laws and regulations applicable to our operations include those controlling the discharge of materials into the environment, requiring removal and cleanup of materials that may harm the environment, requiring consistency with applicable coastal zone management plans, or otherwise relating to the protection of the environment.

Solid and Hazardous Waste. We currently own or lease, and have in the past owned or leased, numerous properties that were used for the production of oil and gas for many years. Although operating and disposal practices that were standard in the industry at the time may have been utilized, it is possible that hydrocarbons or other wastes may have been disposed of or released on or under the properties currently owned or leased by us. State and federal laws applicable to oil and gas wastes and properties have become more strict over time. Under these increasingly stringent requirements, we could be required to remove or remediate previously disposed wastes (including wastes disposed or released by prior owners and operators) or clean up property contamination (including groundwater contamination by prior owners or operators) or to perform plugging operations to prevent future contamination.

We generate some hazardous wastes that are already subject to the Federal Resource Conservation and Recovery Act (RCRA) and comparable state statutes. The Environmental Protection Agency (EPA) has limited the disposal options for certain hazardous wastes. It is possible that certain wastes currently exempt from treatment as hazardous wastes may in the future be designated as hazardous wastes under RCRA or other applicable statutes. We could, therefore, be subject to more rigorous and costly disposal requirements in the future than we encounter today.

Superfund. The Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), also known as the "Superfund" law, imposes liability, without regard to fault or the legality of the original conduct, on certain persons with respect to the release of hazardous substances into the environment. These persons include the owner and operator of a site and any party that treated or disposed of or arranged for the treatment or disposal of hazardous substances found at a site. CERCLA also authorizes the EPA, and in some cases, private parties, to undertake actions to clean up such hazardous substances, or to recover the costs of such actions from the responsible parties. In the course of business, we have used materials and generated wastes and will continue to use materials and generate wastes that may fall within CERCLA's definition of hazardous substances. We may also be an owner or operator of sites on which hazardous substances have been released. As a result, we may be responsible under CERCLA for all or part of the costs to clean up sites where such substances have been released.

Oil Pollution Act. The Federal Oil Pollution Act of 1990 (OPA) and resulting regulations impose a variety of obligations on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills in waters of the United States. The term "waters of the United States" has been broadly defined to include inland water bodies, including wetlands and intermittent streams. The OPA assigns liability to each responsible party for oil removal costs and a variety of public and private damages. We believe that we substantially comply with the Oil Pollution Act and related federal regulations.

Clean Water Act. The Federal Water Pollution Control Act (Clean Water Act) and resulting regulations, which are primarily implemented through a system of permits, also govern the discharge of certain contaminants into waters of the United States. Sanctions for failure to comply strictly with the Clean Water Act are generally resolved by payment of fines and correction of any identified deficiencies. However, regulatory agencies could require us to cease construction or operation of certain facilities or to cease hauling wastewaters to facilities owned by others that are the source of water discharges. We believe that we substantially comply with the Clean Water Act and related federal and state regulations.

Clean Air Act. Our operations are subject to local, state and federal laws and regulations to control emissions from sources of air pollution. Payment of fines and correction of any identified deficiencies generally resolve penalties for failure to comply strictly with air regulations or permits. Regulatory agencies could also require us to cease construction or operation of certain facilities or to install additional controls on certain facilities that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Hydraulic Fracturing. Many of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids — usually consisting mostly of water but typically including small amounts of several chemical additives — as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Greenhouse Gas. In response to recent studies suggesting that emissions of carbon dioxide and certain other gases may be contributing to warming of the Earth's atmosphere, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases from sources within the United States between 2012 and 2050. For example, the 110th session of Congress considered various bills that proposed a "cap and trade" scheme of regulation of greenhouse gas emissions that generally would ban emissions above a defined reducing annual cap. Covered parties would be authorized to emit greenhouse emissions through the acquisition and subsequent surrender of emission allowances that may be traded or acquired on the open market. In addition, at least 17 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. Most of these cap and trade programs require either major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries or gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year until the overall greenhouse gas emission reduction goal is achieved.

Depending on the particular program, we could be required to purchase and surrender allowances, either for greenhouse gas emissions resulting from our operations or from combustion of oil or natural gas we produce. Although we would not be impacted to a greater degree than other similarly situated producers of oil and gas, a stringent greenhouse gas control program could have an adverse effect on our cost of doing business and could reduce demand for the oil and gas we produce.

Also, in the wake of the U.S. Supreme Court's decision in April 2007 in Massachusetts v. Environmental Protection Agency, the EPA has begun to regulate carbon dioxide and other greenhouse gas emissions, even though Congress has yet to adopt new legislation specifically addressing emissions of greenhouse gases. In late 2009, the EPA issued a "Mandatory Reporting of Greenhouse Gases" final rule, which establishes a new comprehensive regulation and reporting scheme for operators of stationary sources emitting certain levels of greenhouse gases, and a Final Rule finding that certain current and projected levels of greenhouse gases in the atmosphere threaten public health and welfare of current and future generations. Please read "Item 1A. Risk Factors − Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for oil and gas."

Employees

As of December 31, 2009, we had 567 active employees. We recognize that our success is significantly influenced by the relationship we maintain with our employees. Overall, we believe that our relations with our employees are satisfactory. The Company and its employees are not represented by a collective bargaining agreement.

Website Access to Company Reports

We make available free of charge through our website, www.cabotog.com, our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission (SEC). Information on our website is not a part of this report. In addition, the SEC maintains an Internet site at www.sec.gov that contains reports, proxy and information statements and other information filed by the Company. The public may read and copy materials that we file with the SEC at the SEC's Public Reference Room located at 100 F Street, NE, Washington, DC 20549. Information regarding the operation of the Public Reference Room can be obtained by calling the SEC at 1-800-SEC-0330.

Corporate Governance Matters

The Company's Corporate Governance Guidelines, Corporate Bylaws, Code of Business Conduct, Corporate Governance and Nominations Committee Charter, Compensation Committee Charter and Audit Committee Charter are available on the Company's website at www.cabotog.com, under the "Corporate Governance" section of "Investor Relations." Requests can also be made in writing to Investor Relations at our corporate headquarters at Three Memorial City Plaza, 840 Gessner Road, Suite 1400, Houston, Texas, 77024.

ITEM 1A. RISK FACTORS

Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business.

Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Lower commodity prices may reduce the amount of natural gas and oil that we can produce economically. Historically, natural gas and oil prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Natural gas prices have declined from approximately $13 per Mmbtu in mid 2008 to an average price of $3.99 per Mmbtu in 2009. Oil prices have declined from record levels in mid 2008 of approximately $145 per barrel to an average price of $62 per barrel in 2009. The forward price for both natural gas and oil currently stands at rates higher than those realized in 2009. Depressed prices in the future would have a negative impact on our future financial results. Because our reserves are predominantly natural gas, changes in natural gas prices have a particularly large impact on our financial results.

Prices for natural gas and oil are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas and oil, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

- the level of consumer product demand;
- weather conditions;
- political conditions in natural gas and oil producing regions, including the Middle East;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the price of foreign imports;
- actions of governmental authorities;
- pipeline availability and capacity constraints;
- inventory storage levels;
- domestic and foreign governmental regulations;
- the price, availability and acceptance of alternative fuels; and
- overall economic conditions.

These factors and the volatile nature of the energy markets make it impossible to predict with any certainty the future prices of natural gas and oil. If natural gas prices decline significantly for a sustained period of time, the lower prices may adversely affect our ability to make planned expenditures, raise additional capital or meet our financial obligations.

Drilling natural gas and oil wells is a high-risk activity.

Our growth is materially dependent upon the success of our drilling program. Drilling for natural gas and oil involves numerous risks, including the risk that no commercially productive natural gas or oil reservoirs will be encountered. The cost of drilling, completing and operating wells is substantial and uncertain, and drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors beyond our control, including:

- unexpected drilling conditions, pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental requirements; and
- shortages or delays in the availability of drilling rigs or crews and the delivery of equipment.

Our future drilling activities may not be successful and, if unsuccessful, such failure will have an adverse effect on our future results of operations and financial condition. Our overall drilling success rate or our drilling success rate for activity within a particular geographic area may decline. We may ultimately not be able to lease or drill identified or budgeted prospects within our expected time frame, or at all. We may not be able to lease or drill a particular prospect because, in some cases, we identify a prospect or drilling location before seeking an option or lease rights in the prospect or location. Similarly, our drilling schedule may vary from our capital budget. The final determination with respect to the drilling of any scheduled or budgeted wells will be dependent on a number of factors, including:

- the results of exploration efforts and the acquisition, review and analysis of the seismic data;
- the availability of sufficient capital resources to us and the other participants for the drilling of the prospects;
- the approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for natural gas and oil and the availability of drilling rigs and crews;
- our financial resources and results; and
- the availability of leases and permits on reasonable terms for the prospects.

These projects may not be successfully developed and the wells, if drilled, may not encounter reservoirs of commercially productive natural gas or oil.

Our proved reserves are estimates. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated or understated.

Reserve engineering is a subjective process of estimating underground accumulations of natural gas and crude oil that cannot be measured in an exact manner. The process of estimating quantities of proved reserves is complex and inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as natural gas and oil prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds.

Results of drilling, testing and production subsequent to the date of an estimate may justify revising the original estimate. Accordingly, initial reserve estimates often vary from the quantities of natural gas and crude oil that are ultimately recovered, and such variances may be material. Any significant variance could reduce the estimated quantities and present value of our reserves.

You should not assume that the present value of future net cash flows from our proved reserves is the current market value of our estimated natural gas and oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows for reporting requirements in compliance with the Financial Accounting Standards Board (FASB) in Accounting Standards Codification 932 may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable.

In general, the production rate of natural gas and oil properties declines as reserves are depleted, with the rate of decline depending on reservoir characteristics. Unless we successfully replace the reserves that we produce, our reserves will decline, eventually resulting in a decrease in natural gas and oil production and lower revenues and cash flow from operations. Our future natural gas and oil production is, therefore, highly dependent on our level of success in finding or acquiring additional reserves. We may not be able to replace reserves through our exploration, development and exploitation activities or by acquiring properties at acceptable costs. Low natural gas and oil prices may further limit the kinds of reserves that we can develop economically. Lower prices also decrease our cash flow and may cause us to decrease capital expenditures.

Our reserve report estimates that production from our proved developed producing reserves as of December 31, 2009 will increase at an estimated rate of 4% during 2010 and then decline at estimated rates of 20%, 12% and 11% during 2011, 2012 and 2013, respectively. Future development of proved undeveloped and other reserves currently not classified as proved developed producing will impact these rates of decline. Because of higher initial decline rates from newly developed reserves, we consider this pattern fairly typical.

Exploration, development and exploitation activities involve numerous risks that may result in dry holes, the failure to produce natural gas and oil in commercial quantities and the inability to fully produce discovered reserves.

Acquired properties may not be worth what we pay due to uncertainties in evaluating recoverable reserves and other expected benefits, as well as potential liabilities.

Successful property acquisitions require an assessment of a number of factors beyond our control. These factors include exploration potential, future natural gas and oil prices, operating costs, and potential environmental and other liabilities. These assessments are complex and inherently imprecise. Our review of the properties we acquire may not reveal all existing or potential problems. In addition, our review may not allow us to fully assess the potential deficiencies of the properties. We do not inspect every well, and even when we inspect a well we may not discover structural, subsurface, or environmental problems that may exist or arise. We may not be entitled to contractual indemnification for pre-closing liabilities, including environmental liabilities, and our contractual indemnification may not be effective. Often, we acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. If an acquired property is not performing as originally estimated, we may have an impairment which could have a material adverse effect on our financial position and results of operations.

The integration of the properties we acquire could be difficult, and may divert management’s attention away from our existing operations.

The integration of the properties we acquire could be difficult, and may divert management’s attention and financial resources away from our existing operations. These difficulties include:

- the challenge of integrating the acquired properties while carrying on the ongoing operations of our business; and
- the possibility of faulty assumptions underlying our expectations.

The process of integrating our operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our existing business. If management is not able to effectively manage the integration process, or if any significant business activities are interrupted as a result of the integration process, our business could suffer.

We face a variety of hazards and risks that could cause substantial financial losses.

Our business involves a variety of operating risks, including:

- well site blowouts, cratering and explosions;
- equipment failures;
- uncontrolled flows of natural gas, oil or well fluids;
- fires;
- formations with abnormal pressures;
- pollution and other environmental risks; and
- natural disasters.

In addition, we conduct operations in shallow offshore areas (largely coastal waters), which are subject to additional hazards of marine operations, such as capsizing, collision and damage from severe weather. Any of these events could result in injury or loss of human life, loss of hydrocarbons, significant damage to or destruction of property, environmental pollution, regulatory investigations and penalties, impairment of our operations and substantial losses to us.

Our operation of natural gas gathering and pipeline systems also involves various risks, including the risk of explosions and environmental hazards caused by pipeline leaks and ruptures. The location of pipelines near populated areas, including residential areas, commercial business centers and industrial sites, could increase these risks. As of December 31, 2009, we owned or operated approximately 3,500 miles of natural gas gathering and pipeline systems. As part of our normal maintenance program, we have identified certain segments of our pipelines that we believe periodically require repair, replacement or additional maintenance.

Federal and state legislation and regulatory initiatives related to hydraulic fracturing could result in increased costs and operating restrictions or delays.

Bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at well sites as well as increased costs to make wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. Such disclosure could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

We may not be insured against all of the operating risks to which we are exposed.

We maintain insurance against some, but not all, of these risks and losses. We do not carry business interruption insurance. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial position and results of operations.

We have limited control over the activities on properties we do not operate.

Other companies operate some of the properties in which we have an interest. Non-operated wells represented approximately 15% of our total owned gross wells, or approximately 5% of our owned net wells, as of December 31, 2009. We have limited ability to influence or control the operation or future development of these non-operated properties or the amount of capital expenditures that we are required to fund with respect to them. The failure of an operator of our wells to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in ways that are in our best interest could reduce our production and revenues. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence or control the operation and future development of these properties could materially adversely affect the realization of our targeted returns on capital in drilling or acquisition activities and lead to unexpected future costs.

Terrorist activities and the potential for military and other actions could adversely affect our business.

The threat of terrorism and the impact of military and other action have caused instability in world financial markets and could lead to increased volatility in prices for natural gas and oil, all of which could adversely affect the markets for our operations. Future acts of terrorism could be directed against companies operating in the United States. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of terrorist organizations. These developments have subjected our operations to increased risk and, depending on their ultimate magnitude, could have a material adverse effect on our business.

Our ability to sell our natural gas and oil production could be materially harmed if we fail to obtain adequate services such as transportation and processing.

The sale of our natural gas and oil production depends on a number of factors beyond our control, including the availability and capacity of transportation and processing facilities. Our failure to obtain these services on acceptable terms could materially harm our business.

Competition in our industry is intense, and many of our competitors have substantially greater financial and technological resources than we do, which could adversely affect our competitive position.

Competition in the natural gas and oil industry is intense. Major and independent natural gas and oil companies actively bid for desirable natural gas and oil properties, as well as for the equipment and labor required to operate and develop these properties. Our competitive position is affected by price, contract terms and quality of service, including pipeline connection times, distribution efficiencies and reliable delivery record. Many of our competitors have financial and technological resources and exploration and development budgets that are substantially greater than ours. These companies may be able to pay more for exploratory projects and productive natural gas and oil properties and may be able to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. In addition, these companies may be able to expend greater resources on the existing and changing technologies that we believe are and will be increasingly important to attaining success in the industry.

We may have hedging arrangements that expose us to risk of financial loss and limit the benefit to us of

increases in prices for natural gas and oil.

From time to time, when we believe that market conditions are favorable, we use certain derivative financial instruments to manage price risks associated with our production in all of our regions. While there are many different types of derivatives available, in 2009 we employed natural gas and crude oil price collar and swap agreements for portions of our 2009 through 2010 production to attempt to manage price risk more effectively. In addition, we entered into natural gas basis swaps covering a portion of anticipated 2012 production, which do not qualify for hedge accounting. The collar arrangements are put and call options used to establish floor and ceiling commodity prices for a fixed volume of production during a certain time period. They provide for payments to counterparties if the index price exceeds the ceiling and payments from the counterparties if the index price falls below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place. These hedging arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

- a counterparty is unable to satisfy its obligations;
- production is less than expected; or
- there is an adverse change in the expected differential between the underlying price in the derivative instrument and actual prices received for our production.

We will continue to evaluate the benefit of employing derivatives in the future. Please read “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in Item 7 and “Quantitative and Qualitative Disclosures about Market Risk” in Item 7A for further discussion concerning our use of derivatives.

The loss of key personnel could adversely affect our ability to operate.

Our operations are dependent upon a relatively small group of key management and technical personnel, and one or more of these individuals could leave our employment. The unexpected loss of the services of one or more of these individuals could have a detrimental effect on us. In addition, our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers and other professionals. Competition for experienced geologists, engineers and some other professionals is extremely intense. If we cannot retain our technical personnel or attract additional experienced technical personnel, our ability to compete could be harmed.

We are subject to complex laws and regulations, including environmental regulations, which can adversely affect the cost, manner or feasibility of doing business.

Our operations are subject to extensive federal, state and local laws and regulations, including tax laws and regulations and those relating to the generation, storage, handling, emission, transportation and discharge of materials into the environment. These laws and regulations can adversely affect the cost, manner or feasibility of doing business. Many laws and regulations require permits for the operation of various facilities, and these permits are subject to revocation, modification and renewal. Governmental authorities have the power to enforce compliance with their regulations, and violations could subject us to fines, injunctions or both. These laws and regulations have increased the costs of planning, designing, drilling, installing and operating natural gas and oil facilities. In addition, we may be liable for environmental damages caused by previous owners of property we purchase or lease. Risks of substantial costs and liabilities related to environmental compliance issues are inherent in natural gas and oil operations. It is possible that other developments, such as stricter environmental laws and regulations, and claims for damages to property or persons resulting from natural gas and oil production, would result in substantial costs and liabilities.

Climate change and climate change legislation and regulatory initiatives could result in increased operating costs and decreased demand for the oil and gas that we produce.

There is increasing attention in the United States and worldwide concerning the issue of climate change and the effect of greenhouse gases. On September 22, 2009, the EPA issued a "Mandatory Reporting of Greenhouse Gases" final rule ("Reporting Rule"). The Reporting Rule establishes a new comprehensive scheme requiring operators of stationary sources emitting more than established annual thresholds of carbon dioxide-equivalent greenhouse gases to inventory and report their greenhouse gases emissions annually on a facility-by-facility basis. In addition, on December 15, 2009, the EPA published a Final Rule finding that current and projected concentrations of six key greenhouse gases in the atmosphere threaten public health and the welfare of current and future generations. The EPA also found that the combined emissions of these greenhouse gases from new motor vehicles and new motor vehicle engines contribute to pollution that threatens public health and welfare. This Final Rule, also known as the EPA's Endangerment Finding, does not impose any requirements on industry or other entities directly. However, the EPA must now finalize motor vehicle greenhouse gases standards, the effect of which could reduce demand for motor fuels refined from crude oil. Finally, according to the EPA, the final motor vehicle greenhouse gas standards will trigger construction and operating permit requirements for stationary sources. Moreover, in 2005, the Kyoto Protocol to the 1992 United Nations Framework Convention on Climate Change, which establishes a binding set of emission targets for greenhouse gases, became binding on all those countries that had ratified it. International discussions are currently underway to develop a treaty to replace the Kyoto Protocol after its expiration in 2012. While it is not possible at this time to predict how regulation that may be enacted to address greenhouse gases emissions would impact our business, the modification of existing laws or regulations or the adoption of new laws or regulations curtailing oil and gas exploration in the areas of the United States in which we operate could materially and adversely affect our operations by limiting drilling opportunities or imposing materially increased costs. In addition, existing or new laws, regulations or treaties (including incentives to conserve energy or use alternative energy sources) could have a negative impact on our business if such incentives reduce demand for oil and gas.

The proposed U.S. federal budget for fiscal year 2011 includes certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations, and cash flows.

On February 1, 2010, the Office of Management and Budget released a summary of the proposed U.S. federal budget for fiscal year 2011. The proposed budget repeals many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposes new taxes. The provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; increases in the taxation of foreign source income; levy of an excise tax on Gulf of Mexico oil and gas production; repeal of the manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law, our taxes will increase, potentially significantly, which would have a negative impact on our net income and cash flows. This could also reduce our drilling activities in the U.S. Since none of these proposals have yet to be voted on or become law, we do not know the ultimate impact these proposed changes may have on our business.

Provisions of Delaware law and our bylaws and charter could discourage change in control transactions and prevent stockholders from receiving a premium on their investment.

Our bylaws provide for a classified Board of Directors with staggered terms, and our charter authorizes our Board of Directors to set the terms of preferred stock. In addition, Delaware law contains provisions that impose restrictions on business combinations with interested parties. Our bylaws prohibit stockholder action by written consent and limit stockholder proposals at meetings of stockholders. Because of these provisions of our charter, bylaws and Delaware law, persons considering unsolicited tender offers or other unilateral takeover proposals may be more likely to negotiate with our Board of Directors rather than pursue non-negotiated takeover attempts. As a result, these provisions may make it more difficult for our stockholders to benefit from transactions that are opposed by an incumbent Board of Directors.

The personal liability of our directors for monetary damages for breach of their fiduciary duty of care is limited by the Delaware General Corporation Law and by our charter.

The Delaware General Corporation Law allows corporations to limit available relief for the breach of directors' duty of care to equitable remedies such as injunction or rescission. Our charter limits the liability of our directors to the fullest extent permitted by Delaware law. Specifically, our directors will not be personally liable for monetary damages for any breach of their fiduciary duty as a director, except for liability:

- for any breach of their duty of loyalty to the company or our stockholders;
- for acts or omissions not in good faith or that involve intentional misconduct or a knowing violation of law;
- under provisions relating to unlawful payments of dividends or unlawful stock repurchases or redemptions; and
- for any transaction from which the director derived an improper personal benefit.

This limitation may have the effect of reducing the likelihood of derivative litigation against directors, and may discourage or deter stockholders or management from bringing a lawsuit against directors for breach of their duty of care, even though such an action, if successful, might otherwise have benefited our stockholders.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

See Item 1. "Business."

ITEM 3. LEGAL PROCEEDINGS

We are a defendant in various legal proceedings arising in the normal course of our business. All known liabilities are accrued based on management's best estimate of the potential loss. While the outcome and impact of such legal proceedings on us cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our consolidated financial position or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Commitment and Contingency Reserves

When deemed necessary, we establish reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that we could incur approximately $0.9 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact on us cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on our consolidated financial position or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

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

No matters were submitted to a vote of security holders during the fourth quarter of 2009.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 15, 2010 about our executive officers, as such term is defined in Rule 3b-7 of the Securities Exchange Act of 1934, and certain of our other officers.

Name	Age	Position	Officer Since
Dan O. Dinges	56	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	61	Senior Vice President, Chief Operating Officer	1998
Scott C. Schroeder	47	Vice President and Chief Financial Officer	1997
J. Scott Arnold	56	Vice President, Land and General Counsel	1998
Robert G. Drake	62	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	63	Vice President, Human Resources	1998
Jeffrey W. Hutton	54	Vice President, Marketing	1995
Lisa A. Machesney	54	Vice President, Managing Counsel and Corporate Secretary	1995
Phillip L. Stalnaker	50	Vice President, North Region	2009
Henry C. Smyth	63	Vice President, Controller and Treasurer	1998
James M. Reid	58	Vice President, South Region	2009

All officers are elected annually by our Board of Directors. All of the executive officers have been employed by Cabot Oil & Gas Corporation for at least the last five years.

Phillip L. Stalnaker was elected Vice President and Regional Manager, North Region, in July 2009. From February 2006 to July 2009, Mr. Stalnaker served as Regional Manager for the Western Region and from 2001 to 2006 as Engineering Manager, Western Region. Prior thereto, Mr. Stalnaker served in various capacities of increasing responsibility within the drilling, production and reserve engineering departments at Chevron Corporation.

James M. Reid was elected Vice President and Regional Manager, South Region, in July 2009. From February 2006 to July 2009, Mr. Reid served as Regional Manager, Gulf Coast Region and from 200l to 2006 as Manager, Regional Operation for the Gulf Coast Region. Prior thereto, Mr. Reid served in various operating and engineering positions with Texaco, Inc., Texas Gas Exploration, Total Minatome, Energy Development Corp. and Broughton Operating Corp.

PART II

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

Our common stock is listed and principally traded on the New York Stock Exchange under the ticker symbol "COG." The following table presents the high and low closing sales prices per share of our common stock during certain periods, as reported in the consolidated transaction reporting system. Cash dividends paid per share of the common stock are also shown. A regular dividend has been declared each quarter since we became a public company in 1990.

	High	Low	Dividends
2009			
First Quarter..........	**$ 30.76**	**$ 18.14**	**$ 0.03**
Second Quarter......	**$ 36.90**	**$ 24.38**	**$ 0.03**
Third Quarter........	**$ 39.23**	**$ 27.98**	**$ 0.03**
Fourth Quarter......	**$ 45.73**	**$ 34.14**	**$ 0.03**
2008			
First Quarter............	$ 53.41	$ 37.67	$ 0.03
Second Quarter........	$ 71.11	$ 51.48	$ 0.03
Third Quarter...........	$ 68.58	$ 33.58	$ 0.03
Fourth Quarter.........	$ 33.83	$ 21.31	$ 0.03

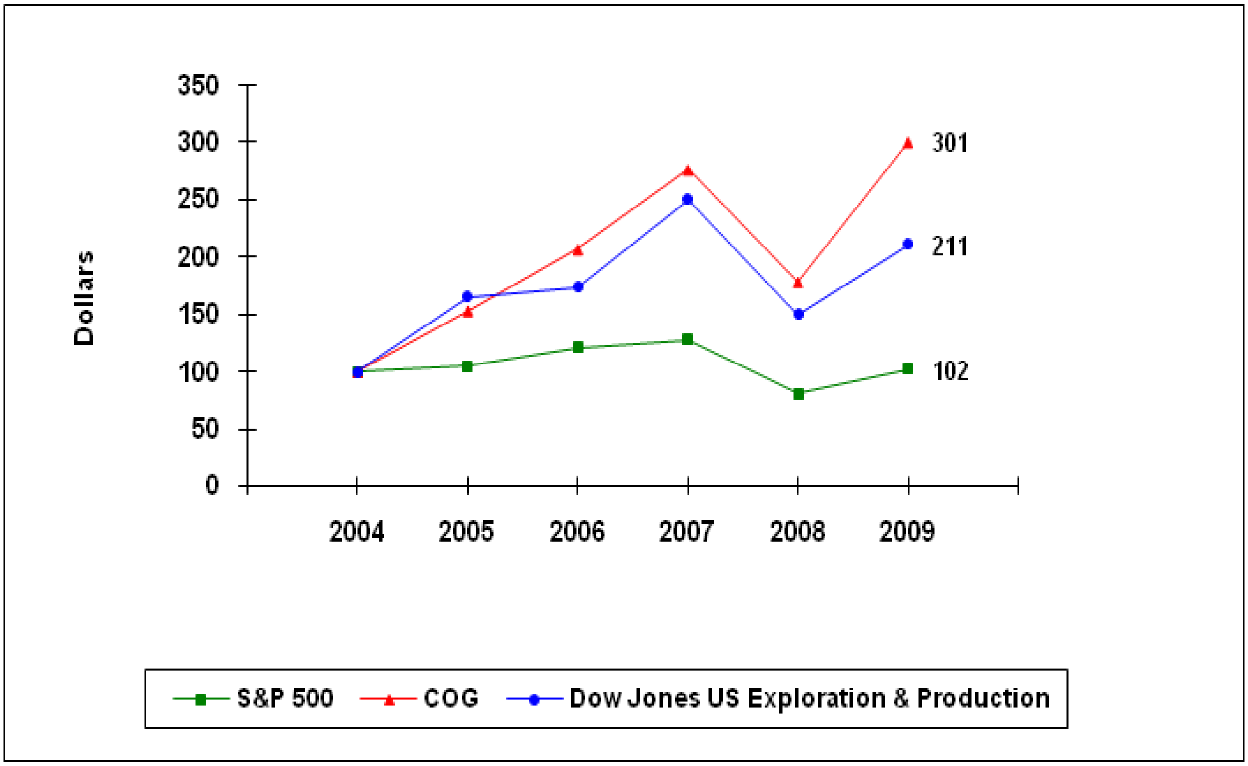
As of February 1, 2010, there were 515 registered holders of the common stock. Shareholders include individuals, brokers, nominees, custodians, trustees, and institutions such as banks, insurance companies and pension funds. Many of these hold large blocks of stock on behalf of other individuals or firms.

ISSUER PURCHASES OF EQUITY SECURITIES

Our Board of Directors has authorized a share repurchase program under which we may purchase shares of common stock in the open market or in negotiated transactions. There is no expiration date associated with the authorization. During 2009, we did not repurchase any shares of common stock. All purchases executed to date have been through open market transactions. The maximum number of shares that may yet be purchased under the plan as of December 31, 2009 was 4,795,300.

PERFORMANCE GRAPH

The following graph compares our common stock performance ("COG") with the performance of the Standard & Poors' 500 Stock Index and the Dow Jones US Exploration & Production Index for the period December 2004 through December 2009. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2004 and that all dividends were reinvested.



CALCULATED VALUES	2004	2005	2006	2007	2008	2009
S&P 500	100.0	104.9	121.5	128.2	80.7	102.1
COG	100.0	153.5	207.1	276.5	178.6	300.5
Dow Jones US Exploration & Production	100.0	165.3	174.2	250.3	149.9	210.6

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

ITEM 6. SELECTED FINANCIAL DATA

The following table summarizes our selected consolidated financial data for the periods indicated. This information should be read in conjunction with Management's Discussion and Analysis of Financial Condition and Results of Operations in Item 7, and the Consolidated Financial Statements and related Notes in Item 8.

	Year Ended December 31,				
(In thousands, except per share amounts)	**2009**	2008	2007	2006	2005
Statement of Operations Data					
Operating Revenues	**$ 879,276**	$ 945,791	$ 732,170	$ 761,988	$ 682,797
Impairment of Oil & Gas Properties and Other Assets [1]	**17,622**	35,700	4,614	3,886	-
Gain / (Loss) on Sale of Assets [2]	**(3,303)**	1,143	13,448	232,017	74
Gain on Settlement of Dispute [3]	**-**	51,906	-	-	-
Income from Operations	**282,269**	372,012	274,693	528,946	258,731
Net Income	**148,343**	211,290	167,423	321,175	148,445
Basic Earnings per Share [4]	**$ 1.43**	$ 2.10	$ 1.73	$ 3.32	$ 1.52
Diluted Earnings per Share [4]	**$ 1.42**	$ 2.08	$ 1.71	$ 3.26	$ 1.49
Dividends per Common Share [4]	**$ 0.120**	$ 0.120	$ 0.110	$ 0.080	$ 0.074
Balance Sheet Data					
Properties and Equipment, Net	**$ 3,358,199**	$ 3,135,828	$ 1,908,117	$ 1,480,201	$ 1,238,055
Total Assets	**3,683,401**	3,701,664	2,208,594	1,834,491	1,495,370
Current Portion of Long-Term Debt	**-**	35,857	20,000	20,000	20,000
Long-Term Debt	**805,000**	831,143	330,000	220,000	320,000
Stockholders' Equity	**1,812,514**	1,790,562	1,070,257	945,198	600,211

(1) *For discussion of impairment of oil and gas properties and other assets, refer to Note 2 of the Notes to the Consolidated Financial Statements.*

(2) *Gain on Sale of Assets for 2007 and 2006 reflects $12.3 million and $231.2 million, respectively, related to disposition of our offshore portfolio and certain south Louisiana properties (the "2006 south Louisiana and offshore properties sale"), which was substantially completed in the third quarter of 2006.*

(3) *Gain on Settlement of Dispute is associated with the Company's settlement of a dispute in the fourth quarter of 2008. The dispute settlement includes the value of cash and properties received. See Note 7 of the Notes to the Consolidated Financial Statements.*

(4) *All Earnings per Share and Dividends per Common Share figures have been retroactively adjusted for the 2-for-1 split of our common stock effective March 31, 2007 as well as the 3-for-2 split of our common stock effective March 31, 2005.*

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

The following discussion is intended to assist you in understanding our results of operations and our present financial condition. Our Consolidated Financial Statements and the accompanying Notes to the Consolidated Financial Statements included elsewhere in this Form 10-K contain additional information that should be referred to when reviewing this material.

Certain prior year amounts have been reclassified to reflect changes in presenting the geographic areas in which we conduct our operations. These areas consist of the North (comprised of the East and Rocky Mountain areas) and South (comprised of the Gulf Coast and Anadarko areas). In previous periods, we presented the geographic areas as East, Gulf Coast, West and Canada.

Statements in this discussion may be forward-looking. These forward-looking statements involve risks and uncertainties, including those discussed below, which could cause actual results to differ from those expressed. Please read "Forward-Looking Information" for further details.

We operate in one segment, natural gas and oil development, exploitation and exploration, exclusively within the United States. In April 2009, we sold substantially all of our Canadian properties to a private Canadian company.

OVERVIEW

Cabot Oil & Gas Corporation is a leading independent oil and gas company engaged in the development, exploitation, exploration, production and marketing of natural gas, and to a lesser extent, crude oil and natural gas liquids from its properties in the Continental U.S. We also transport, store, gather and produce natural gas for resale. Our exploitation and exploration activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. Our program is designed to be disciplined and balanced, with a focus on achieving strong financial returns.

At Cabot, we evaluate three types of investment alternatives that compete for available capital: drilling opportunities, financial opportunities such as debt repayment or repurchase of common stock and acquisition opportunities. Depending on circumstances, we allocate capital among the alternatives based on a rate-of-return approach. Our goal is to invest capital in the highest return opportunities available at any given time. At any one time, one or more of these may not be economically feasible.

Our financial results depend upon many factors, particularly the price of natural gas and crude oil and our ability to market our production on economically attractive terms. Price volatility in the commodity markets has remained prevalent in the last few years. Throughout 2009 commodity index prices in general traded in a range significantly below recent highs. However, our realized natural gas and crude oil price was $7.47 per Mcf and $85.52 per Bbl, respectively, in 2009 and were significantly increased by our positions from our derivative instruments, which contributed approximately 45% of our realized revenues in 2009. In an effort to manage commodity price risk, we entered into a series of crude oil and natural gas price swaps and collars. These financial instruments are an important element of our risk management strategy.

Commodity prices are impacted by many factors that are outside of our control. Historically, commodity prices have been volatile and we expect them to remain volatile. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, weather, pipeline capacity constraints, inventory storage levels, basis differentials and other factors. As a result, we cannot accurately predict future natural gas, NGL and crude oil prices and, therefore, we cannot determine with any degree of certainty what effect increases or decreases will have on our capital program, production volumes and future revenues. In addition to production volumes and commodity prices, finding and developing sufficient amounts of crude oil and natural gas reserves at economical costs are critical to our long-term success. See "Risk Factors—Natural gas and oil prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business" and "Risk Factors—Our future performance depends on our ability to find or acquire additional natural gas and oil reserves that are economically recoverable" in Item 1A.

The tables below illustrate how natural gas prices have fluctuated by month over 2008 and 2009. "Index" represents the first of the month Henry Hub index price per Mmbtu. The "2008" and "2009" price is the natural gas price per Mcf realized by us and includes the realized impact of our natural gas price collar and swap arrangements, as applicable:

Natural Gas Prices by Month - 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$ 6.16**	**$ 4.49**	**$ 4.07**	**$ 3.65**	**$ 3.33**	**$ 3.54**	**$ 3.96**	**$ 3.37**	**$ 2.84**	**$ 3.72**	**$ 4.28**	**$ 4.49**
2009	**$ 7.72**	**$ 7.32**	**$ 7.46**	**$ 7.03**	**$ 7.28**	**$ 7.45**	**$ 7.50**	**$ 7.45**	**$ 7.25**	**$ 7.42**	**$ 8.03**	**$ 7.75**

Natural Gas Prices by Month - 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 7.13	$ 8.01	$ 8.96	$ 9.59	$ 11.29	$ 11.93	$ 13.11	$ 9.23	$ 8.40	$ 7.48	$ 6.47	$ 6.90
2008	$ 7.46	$ 7.82	$ 8.45	$ 9.03	$ 9.38	$ 9.50	$ 9.36	$ 8.61	$ 8.05	$ 7.89	$ 7.70	$ 7.54

Prices for crude oil rose to record high levels in 2008, but experienced significant declines in the fourth quarter of 2008. Prices improved during 2009. The tables below contain the NYMEX monthly average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2008 and 2009. The "2008" and "2009" price is the crude oil price per Bbl realized by us and includes the realized impact of our crude oil derivative arrangements:

Crude Oil Prices by Month - 2009

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	**$ 41.92**	**$ 39.26**	**$ 48.06**	**$ 49.95**	**$ 59.21**	**$ 69.70**	**$ 64.29**	**$ 71.14**	**$ 69.47**	**$ 75.82**	**$ 78.15**	**$ 74.60**
2009	**$ 75.41**	**$ 73.98**	**$ 76.29**	**$ 78.86**	**$ 85.94**	**$ 86.26**	**$ 82.22**	**$ 92.16**	**$ 87.54**	**$ 92.13**	**$ 95.35**	**$ 95.41**

Crude Oil Prices by Month - 2008

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 92.93	$ 95.35	$ 105.42	$ 112.46	$ 125.46	$ 134.02	$ 133.48	$ 116.69	$ 103.76	$ 76.72	$ 57.44	$ 42.04
2008	$ 83.71	$ 85.02	$ 90.85	$ 92.56	$ 99.79	$ 103.83	$ 102.76	$ 101.16	$ 93.51	$ 87.10	$ 69.16	$ 62.45

We reported earnings of $1.43 per share, or $148.3 million, for 2009, a decrease from the $2.10 per share, or $211.3 million, reported in 2008. Natural gas revenues decreased from 2008 to 2009 as a result of decreased commodity market prices, partially offset by increased natural gas production and favorable natural gas hedge settlements. Crude oil revenues remained flat from 2008 to 2009 primarily due to increased crude oil production and favorable oil hedge settlements, offset by a decrease in realized prices. Prices, including the realized impact of derivative instruments, decreased by 11% for natural gas and 4% for oil.

We drilled 143 gross wells with a success rate of 95% in 2009 compared to 432 gross wells with a success rate of 97% in 2008. Total capital and exploration expenditures decreased by $840.6 million to $640.4 million in 2009 compared to $1,481.0 million (including the east Texas acquisition) in 2008. This decrease was largely due to the $604 million acquisition of east Texas assets in 2008 and a decrease of $231.9 million in total drilling. We believe our cash on hand and operating cash flow in 2010 will be sufficient to fund our budgeted capital and exploration spending of approximately $585 million. Any additional needs are expected to be funded by borrowings from our credit facility.

Our 2010 strategy will remain consistent with 2009. We will remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we intend to maintain spending discipline and manage our balance sheet in an effort to ensure sufficient liquidity, including cash resources and available credit. In the current year we have allocated our planned program for capital and exploration expenditures primarily to the Marcellus Shale in northeast Pennsylvania, and to a lesser extent east Texas. We believe these strategies are appropriate for our portfolio of projects and the current industry environment and will continue to add shareholder value over the long-term.

The preceding paragraphs, discussing our strategic pursuits and goals, contain forward-looking information. Please read "Forward-Looking Information" for further details.

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2009 were from funds generated from the sale of natural gas and crude oil production (including hedge realizations) and, to a lesser extent, the sales of properties during the year and borrowings under our revolving credit facility. These cash flows were primarily used to fund our development and exploratory expenditures, in addition to payments for debt service, debt issuance costs, contributions to our pension plan and dividends. See below for additional discussion and analysis of cash flow.

We generate cash from the sale of natural gas and crude oil. Operating cash flow fluctuations are substantially driven by commodity prices and changes in our production volumes. Prices for crude oil and natural gas have historically been volatile, including seasonal influences characterized by peak demand and higher prices in the winter heating season; however, the impact of other risks and uncertainties have also influenced prices throughout the recent years. Commodity prices have recently experienced increased volatility due to adverse market conditions in our economy. In addition, fluctuations in cash flow may result in an increase or decrease in our capital and exploration expenditures. See "Results of Operations" for a review of the impact of prices and volumes on sales.

Our working capital is also substantially influenced by variables discussed above. From time to time, our working capital will reflect a surplus, while at other times it will reflect a deficit. This fluctuation is not unusual. We believe we have adequate credit availability and liquidity available to meet our working capital requirements.

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Cash Flows Provided by Operating Activities	**$ 614,052**	$ 634,447	$ 462,137
Cash Flows Used in Investing Activities	**(531,027)**	(1,452,289)	(589,922)
Cash Flows Provided by / (Used in) Financing Activities	**(70,968)**	827,445	104,429
Net Increase / (Decrease) in Cash and Cash Equivalents	**$ 12,057**	$ 9,603	$ (23,356)

Operating Activities. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Net cash provided by operating activities in 2009 decreased by $20.4 million over 2008. This decrease was mainly due to a decrease in oil and gas revenues, partially offset by lower operating, interest and tax expense. Average realized natural gas prices decreased by 11% in 2009 compared to 2008 and average realized crude oil prices decreased by 4% over the same period. Equivalent production volumes increased by 8% in 2009 compared to 2008 as a result of higher natural gas and crude oil production. We are unable to predict future commodity prices and, as a result, cannot provide any assurance about future levels of net cash provided by operating activities. Realized prices may continue to decline during 2010.

For 2009, we had natural gas price swaps covering 16.1 Bcf of our 2009 gas production at an average price of $12.18 per Mcf and natural gas price collars covering 47.3 Bcf of our 2009 gas production, with a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf. As of December 31, 2009, we have natural gas price swaps covering 19.3 Bcf of our 2010 gas production at an average price of $9.30 per Mcf, and no natural gas price collars. Accordingly, based on our current hedge position, we will be more subject to the effects of natural gas price volatility in 2010 than in 2009. In addition, given the current market for derivatives, if we were to hedge all our 2010 production, we would expect our realized prices to be lower than our 2009 realized prices.

Net cash provided by operating activities in 2008 increased by $172.3 million over 2007. This increase was mainly due to an increase in net income, the receipt of cash of $20.2 million in 2008 in connection with the settlement of a dispute and an increase of $13.7 million in cash received for income tax refunds. In addition, cash flows from operating activities increased as a result of other working capital changes. Average realized natural gas prices increased by 16% in 2008 over 2007 and average realized crude oil prices increased by 33% over the same period. Equivalent production volumes increased by 11% in 2008 compared to 2007 as a result of higher natural gas production.

See “Results of Operations” for a discussion on commodity prices and a review of the impact of prices and volumes on sales revenue.

Investing Activities. The primary uses of cash in investing activities were capital spending and exploration expenses. We established the budget for these amounts based on our current estimate of future commodity prices and cash flows. Due to the volatility of commodity prices and new opportunities which may arise, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities decreased by $921.3 million from 2008 to 2009 and increased by $862.4 million from 2007 to 2008. The decrease from 2008 to 2009 was due to a decrease of $862.8 million in acquisitions and capital expenditures and an increase of $78.1 million of proceeds from the sale of assets, partially offset by an increase of $19.6 million in exploration expenditures. In August 2008, we completed the acquisition of producing properties, leasehold acreage and a natural gas gathering infrastructure in east Texas for total net cash consideration of approximately $604.0 million.

The increase from 2007 to 2008 was due to an increase of $866.0 million in capital expenditures, including an increase of approximately $601.8 million primarily due to the $604.0 million east Texas acquisition and an increase of $130.5 million related to unproved leasehold acquisitions primarily in northeast Pennsylvania. In addition, there were $5.0 million of lower proceeds from the sale of assets in 2008 compared to 2007. Partially offsetting these increases to cash used in investing activities were decreased exploration expenditures of $8.6 million in 2008 compared to 2007.

Financing Activities. Cash flows provided by financing activities decreased by $898.4 million from 2008 to 2009. This was primarily due to a decrease in borrowings from debt of $787 million, partially offset by a decrease in repayments of debt of $208 million, and a decrease in net proceeds from the sale of common stock of $316.1 million primarily due to our June 2008 issuance of 5,002,500 shares of common stock in a public offering. Common stock proceeds and debt borrowings in 2008 were largely used to finance the acquisition of east Texas properties and undeveloped acreage. Cash paid for capitalized debt issuance costs and dividends increased by a total of $6.4 million, partially offset by an increase of $3.1 million in the tax benefit associated with stock-based compensation.

Cash flows provided by financing activities increased by $723.0 million from 2007 to 2008. This was primarily due to an increase in debt consisting of our July 2008 and December 2008 private placements of debt ($492 million) and an increase of $45 million in borrowings under our revolving credit facility. Additionally, net proceeds from the sale of common stock increased by $311.1 million primarily due to the June 2008 issuance of common stock. The tax benefit for stock-based compensation increased by $10.7 million from 2007 to 2008, but was partially offset by an increase in dividends and capitalized debt issuance costs paid.

At December 31, 2009, we had $143 million of borrowings outstanding under our unsecured credit facility at a weighted-average interest rate of 3.9%. In April 2009, we entered into a new revolving credit facility and terminated our prior credit facility. The new credit facility provides for an available credit line of $500 million and contains an accordion feature allowing us to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The available credit line is subject to adjustment on the basis of the present value of estimated future net cash flows from proved oil and gas reserves (as determined by the banks based on our reserve reports and engineering reports) and certain other assets and the outstanding principal balance of our senior notes. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Our revolving credit facility includes a covenant limiting our total debt. Management believes that, with internally generated cash, existing cash and availability under our revolving credit facility, we have the capacity to finance our spending plans and maintain our strong financial position. At the same time, we will closely monitor the capital markets.

In July 2008, we completed a private placement of $425 million aggregate principal amount of senior unsecured fixed-rate notes with a weighted-average interest rate of 6.51%, consisting of amounts due in July 2018, 2020 and 2023. In December 2008, we completed a private placement of $67 million aggregate principal amount of senior unsecured 9.78% fixed-rate notes due in December 2018. Please refer to Note 4 of the Notes to the Consolidated Financial Statements for further details.

In June 2008, we entered into an underwriting agreement pursuant to which we sold an aggregate of 5,002,500 shares of common stock at a price to us of $62.66 per share. We received $313.5 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used temporarily to reduce outstanding borrowings under our revolving credit facility prior to funding a portion of the purchase price of our east Texas acquisition, which closed in the third quarter of 2008. Immediately prior to (and in connection with) this issuance, we retired 5,002,500 shares of treasury stock, which had a weighted-average purchase price of $16.46.

Capitalization

Information about our capitalization is as follows:

	December 31,			
(Dollars in millions)		**2009**		2008
Debt [1]	**$**	**805.0**	$	867.0
Stockholders' Equity		**1,812.5**		1,790.6
Total Capitalization	**$**	**2,617.5**	$	2,657.6
Debt to Capitalization		**31%**		33%
Cash and Cash Equivalents	**$**	**40.2**	$	28.1

[1] *Includes $35.9 million of current portion of long-term debt at December 31, 2008. Includes $143 million and $185 million of borrowings outstanding under our revolving credit facility at December 31, 2009 and 2008, respectively.*

For the year ended December 31, 2009, we paid dividends of $12.4 million ($0.03 per share) on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990.

Capital and Exploration Expenditures

On an annual basis, we generally fund most of our capital and exploration activities, excluding any significant oil and gas property acquisitions, with cash generated from operations and, when necessary, our revolving credit facility. We budget these capital expenditures based on our projected cash flows for the year.

The following table presents major components of our capital and exploration expenditures for the three years ended December 31, 2009.

(In millions)		**2009**		2008		2007
Capital Expenditures						
Drilling and Facilities [1]	$	**401.1**	$	624.3	$	539.7
Leasehold Acquisitions		**145.7**		152.7		22.2
Acquisitions..............................		**0.4**		625.0		4.0
Pipeline and Gathering.............		**32.9**		36.9		28.2
Other		**9.5**		10.9		2.3
		589.6		1,449.8		596.4
Exploration Expense		**50.8**		31.2		39.8
Total	$	**640.4**	$	1,481.0	$	636.2

[1] *Includes Canadian currency translation effects of $4.6 million, $(27.7) million and $15.0 million in 2009, 2008 and 2007, respectively.*

We plan to drill approximately 136 gross wells (123.9 net) in 2010 compared with 143 gross wells (118.5 net) drilled in 2009. The number of net wells we plan to drill in 2010 is up slightly from 2009. This 2010 drilling program includes approximately $585 million in total capital and exploration expenditures, down from $640.4 million in 2009. This decline is primarily due to lower projected lease acquisition expenditures. We will continue to assess the natural gas and crude oil price environment and our liquidity position and may increase or decrease the capital and exploration expenditures accordingly.

There are many factors that impact our depreciation, depletion and amortization (DD&A) rate. These include reserve additions and revisions, development costs, impairments and changes in anticipated production in future periods. In 2010, management expects an increase in our DD&A rate due to higher capital costs, partially as a result of inflationary cost pressures in the industry over the last four years and increased lease acquisition costs in Pennsylvania. This change is currently estimated to be approximately 11% greater than 2009 levels. This increase will not have an impact on our cash flows.

Contractual Obligations

Our material contractual obligations include long-term debt, interest on long-term debt, firm gas transportation agreements, drilling rig commitments and operating leases. We have no off-balance sheet debt or other similar unrecorded obligations.

A summary of our contractual obligations as of December 31, 2009 are set forth in the following table:

		Payments Due by Year			
(In thousands)	**Total**	2010	2011 to 2012	2013 to 2014	2015 & Beyond
Long-Term Debt [1]	**$ 805,000**	$ -	$ 218,000	$ 75,000	$ 512,000
Interest on Long-Term Debt [2]	**396,857**	52,280	87,914	76,949	179,714
Firm Gas Transportation Agreements [3]	**80,403**	10,977	21,599	6,746	41,081
Drilling Rig Commitments [3]	**6,364**	6,364	-	-	-
Operating Leases [3]	**26,776**	5,845	10,029	8,443	2,459
Total Contractual Cash Obligations	**$ 1,315,400**	$ 75,466	$ 337,542	$ 167,138	$ 735,254

(1) *At December 31, 2009, we had $143 million of debt outstanding under our revolving credit facility. See Note 4 of the Notes to the Consolidated Financial Statements for details of long-term debt.*

(2) *Interest payments have been calculated utilizing the fixed rates of our $662 million long-term debt outstanding at December 31, 2009. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2009 outstanding balance of $143 million will be outstanding through the April 2012 maturity date. A constant interest rate of 3.9% was assumed, which was the 2009 weighted-average interest rate. Actual results will differ from these estimates and assumptions.*

(3) *For further information on our obligations under firm gas transportation agreements, drilling rig commitments and operating leases, see Note 7 of the Notes to the Consolidated Financial Statements.*

Amounts related to our asset retirement obligations are not included in the above table given the uncertainty regarding the actual timing of such expenditures. The total amount of asset retirement obligations at December 31, 2009 was $29.7 million, up from $28.0 million at December 31, 2008, primarily due to $1.3 million of accretion expense during 2009 as well as $0.4 million of drilling additions.

Potential Impact of Our Critical Accounting Policies

Readers of this document and users of the information contained in it should be aware of how certain events may impact our financial results based on the accounting policies in place. The most significant policies are discussed below.

Oil and Gas Reserves

The process of estimating quantities of proved reserves is inherently imprecise, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. The process also requires certain economic assumptions, some of which are mandated by the SEC, such as oil and gas prices. Additional assumptions include drilling and operating expenses, capital expenditures, taxes and availability of funds.

Since 1990, 100% of our reserves have been reviewed by Miller & Lents, Ltd., an independent oil and gas reservoir engineering consulting firm, who in their opinion determined the estimates presented to be reasonable in the aggregate. In 2009, we had a net downward revision of 200.1 Bcfe primarily due to (i) downward revisions of 101.6 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 120.4 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the SEC's new oil and gas reserve calculation methodology, partially offset by 21.9 Bcfe of positive performance revisions. In accordance with the new rules we priced proved oil and gas reserves using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month within the 12-month period prior to the end of the reporting period. We did not record significant reserve revisions during 2008 and 2007. For more information regarding reserve estimation, including historical reserve revisions, refer to the "Supplemental Oil and Gas Information."

Our rate of recording DD&A expense is dependent upon our estimate of proved reserves, which is utilized in our unit-of-production method calculation. If the estimates of proved reserves were to be reduced, the rate at which we record DD&A expense would increase, reducing net income. Such a reduction in reserves may result from lower market prices, which may make it non-economic to drill for and produce higher cost fields. A five percent positive or negative revision to proved reserves throughout the Company would decrease or increase the DD&A rate by approximately $0.07 to $0.09 per Mcfe. Revisions in significant fields may individually affect our DD&A rate. It is estimated that a positive or negative reserve revision of 10% in one of our most productive fields would have a $(0.02) to $0.04 per Mcfe impact on our total DD&A rate. These estimated impacts are based on current data, and actual events could require different adjustments to our DD&A rate.

In addition, a decline in proved reserve estimates may impact the outcome of our impairment test under Accounting Standards Codification (ASC) 360, "Property, Plant, and Equipment." Due to the inherent imprecision of the reserve estimation process, risks associated with the operations of proved producing properties and market sensitive commodity prices utilized in our impairment analysis, management cannot determine if an impairment is reasonably likely to occur in the future.

Carrying Value of Oil and Gas Properties

We evaluate the impairment of our oil and gas properties on a field-by-field basis whenever events or changes in circumstances indicate an asset's carrying amount may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on our estimate of future crude oil and natural gas prices, operating costs and anticipated production from proved reserves are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using a combination of assumptions management uses in its budgeting and forecasting process as well as historical and current prices adjusted for geographical location and quality differentials, as well as other factors that management believes will impact realizable prices. Fair value is calculated by discounting the future cash flows. The discount factor used (16% at December 31, 2009) is based on rates utilized by market participants that are commensurate with the risks inherent in the development and production of the underlying natural gas and oil. In 2009, 2008 and 2007, there were no unusual or unexpected occurrences that caused significant revisions in estimated cash flows which were utilized in our impairment test. In the event that commodity prices remain low or continue to decline, there could be a significant revision in the future.

Costs attributable to our unproved properties are not subject to the impairment analysis described above; however, a portion of the costs associated with such properties is subject to amortization based on past experience and average property lives. Average property lives are determined on a regional basis and based on the estimated life of unproved property leasehold rights. Historically, the average property life in each of the regions has not significantly changed. During the latter part of 2008 and during 2009, commodity prices declined at a significant rate as the global economy struggled with a worldwide recession. This price environment has resulted in reduced capital available for exploration projects as well as development drilling. We have considered these impacts discussed above when assessing the impairment of our undeveloped acreage, especially in exploratory areas. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $19.3 million or decrease by approximately $13.8 million, respectively per year.

In the past, based on the customary terms of the leases, the average leasehold life in the South region has been shorter than the average life in the North region. Average property lives in the North and South regions have been five and three years, respectively. As these properties are developed and reserves are proven, the remaining capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved properties are written off depends on the timing and success of our future exploration program.

Accounting for Derivative Instruments and Hedging Activities

We follow the accounting prescribed in ASC 815. Under ASC 815, the fair value of each derivative instrument is recorded as either an asset or liability on the balance sheet. At the end of each quarterly period, these instruments are marked-to-market. The gain or loss on the change in fair value is recorded as Accumulated Other Comprehensive Income, a component of equity, to the extent that the derivative instrument is designated as a hedge and is effective. Under ASC 815, effectiveness is a measurement of how closely correlated the hedge instrument is with the underlying physical sale. For example, a natural gas price swap that converts Henry Hub index to a fixed price would be perfectly correlated, and 100% effective, if the underlying gas were sold at the Henry Hub index. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of derivatives not qualifying as hedges, is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate in the Consolidated Statement of Operations.

Fair Value Measurements

Effective January 1, 2008, we adopted those provisions of ASC 820, “Fair Value Measurements and Disclosures,” that were required to be adopted (which excluded certain non financial assets and liabilities). Effective January 1, 2009, we applied all of the provisions of ASC 820, and this adoption did not have a material impact on any of our financial statements except for our impairment of oil and gas properties (see Note 2 of the Notes to the Consolidated Financial Statements). In the future, areas that could cause an impact would primarily be limited to asset impairments, including long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any. As defined in ASC 820, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

We utilize market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We attempt to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. We are able to classify fair value balances based on the observability of those inputs. ASC 820 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible.

As of December 31, 2009, we had $114.7 million of financial assets, or 3% of our total assets, classified as Level 3. This was entirely comprised of our derivative receivable balance from our oil and gas cash flow hedges. During 2009, realized gains of $240.9 million were recognized in other comprehensive income. Derivative settlements during the year totaled $395.0 million. The fair values of our natural gas and crude oil price collars and swaps are valued based upon quotes obtained from counterparties to the agreements and are designated as Level 3. Such quotes have been derived using a Black-Scholes model for the active oil and gas commodities market that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. These estimates are compared to multiple quotes obtained from counterparties for reasonableness. We adjust the fair value quotes received by our counterparties to take into account either the counterparties' nonperformance risk or our own nonperformance risk. We measured the nonperformance risk of our counterparties by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions. The resulting reduction to the net receivable derivative contract position was $0.2 million. In times where we have net derivative contract liabilities, our nonperformance risk is evaluated using a market credit spread provided by our bank. Additional disclosures are required for transactions measured at fair value and we have included these disclosures in Note 11 of the Notes to the Consolidated Financial Statements.

Long-Term Employee Benefit Costs

Our costs of long-term employee benefits, particularly pension and postretirement benefits, are incurred over long periods of time, and involve many uncertainties over those periods. The net periodic benefit cost attributable to current periods is based on several assumptions about such future uncertainties, and is sensitive to changes in those assumptions. It is management's responsibility, often with the assistance of independent experts, to select assumptions that in its judgment represent best estimates of those uncertainties. It also is management's responsibility to review those assumptions periodically to reflect changes in economic or other factors that affect those assumptions.

The current benefit service costs, as well as the existing liabilities, for pensions and other postretirement benefits are measured on a discounted present value basis. The discount rate is a current rate, related to the rate at which the liabilities could be settled. Our assumed discount rate is based on average rates of return published for a theoretical portfolio of high-quality fixed income securities. In order to select the discount rate, we use benchmarks such as the Moody's Aa Corporate Rate, which was 5.49% as of December 31, 2009, and the Citigroup Pension Liability Index, which was 5.96% as of December 31, 2009. We look to these benchmarks as well as considering durations of expected benefit payments. We have determined based on these assumptions that a discount rate of 5.75% at December 31, 2009 is reasonable.

In order to value our pension liabilities, we use the IRS 2009 Static Mortality Table based on the demographics of our benefit plans. We have also assumed that salaries will increase four percent based on our expectation of future salary increases.

The benefit obligation and the periodic cost of postretirement medical benefits also are measured based on assumed rates of future increase in the per capita cost of covered health care benefits. As of December 31, 2009, the assumed rate of increase was 10%. The net periodic cost of pension benefits included in expense also is affected by the expected long-term rate of return on plan assets assumption. The expected return on plan assets rate is normally changed less frequently than the assumed discount rate, and reflects long-term expectations, rather than current fluctuations in market conditions. The actual rate of return on plan assets may differ from the expected rate due to the volatility normally experienced in capital markets. Management's goal is to manage the investments over the long-term to achieve optimal returns with an acceptable level of risk and volatility.

We have established objectives regarding plan assets in the pension plan. We attempt to maximize return over the long-term, subject to appropriate levels of risk. One of our plan objectives is that the performance of the equity portion of the pension plan exceed the Standard and Poors' 500 Index over the long-term. We also seek to achieve a minimum five percent annual real rate of return (above the rate of inflation) on the total portfolio over the long-term. We establish the long-term expected rate of return by developing a forward-looking long-term expected rate of return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. In our pension calculations, we have used eight percent as the expected long-term return on plan assets for 2009, 2008 and 2007. A Monte Carlo simulation was run using 5,000 simulations based upon our actual asset allocation and liability duration, which has been determined to be approximately 15 years. This model uses historical data for the period of 1926-2007 for stocks, bonds and cash to determine the best estimate range of future returns. The median rate of return, or return that we expect to achieve over 50 percent of the time, is approximately nine percent. We expect to achieve at a minimum approximately seven percent annual real rate of return on the total portfolio over the long-term at least 75 percent of the time. We believe that the eight percent chosen is a reasonable estimate based on our actual results.

We generally target a portfolio of assets utilizing equity securities, fixed income securities and cash equivalents that are within a range of approximately 50% to 80% for equity securities and approximately 20% to 40% for fixed income securities. Large capitalization equities may make up a maximum of 65% of the portfolio. Small capitalization equities and international equities may make up a maximum of 30% and 15%, respectively, of the portfolio. Fixed income bonds may make up a maximum of 40% of our portfolio. The account will typically be fully invested; however, as a temporary investment or an asset protection measure, part of the account may be invested in money market investments up to 20%. One percent of the portfolio is invested in short-term funds at the designated bank to meet the cash flow needs of the plan. No prohibited investments, including direct or indirect investments in commodities, commodity futures, derivatives, short sales, real estate investment trusts, letter stock, restricted stock or other private placements, are allowed without prior committee approval.

Stock-Based Compensation

We account for stock-based compensation under a fair value based method of accounting prescribed under ASC 718 for stock options and similar equity instruments. Under the fair value method, compensation cost is measured at the grant date based on the value of an award and is recognized over the service period, which is usually the vesting period. To calculate the fair value, either a binomial or Black-Scholes valuation model may be used. Stock-based compensation cost for all types of awards is included in General and Administrative Expense in the Consolidated Statement of Operations.

Stock options and stock appreciation rights (SARs) are granted with an exercise price equal to the average of the high and low trading price of our stock on the grant date. The grant date fair value is calculated by using a Black-Scholes model that incorporates assumptions for stock price volatility, risk free rate of return, expected dividend and expected term. The expected term was derived by reviewing minimum and maximum expected term outputs from the Black-Scholes model based on award type and employee type. This term represents the period of time that awards granted are expected to be outstanding. The stock price volatility was calculated using our historical closing stock price data for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the US Treasury (Nominal 10) within the expected term as measured on the grant date. The expected dividend percentage assumes that we will continue to pay a consistent level of dividend each quarter. Expense is recorded based on a graded-vesting schedule over a three year service period, with one-third of the award becoming exercisable each year on the anniversary date of the grant. The forfeiture rate is determined based on the forfeiture history by type of award and by the group of individuals receiving the award.

The fair value of restricted stock awards, restricted stock units and certain performance share awards (which contain vesting restrictions based either on operating income or internal performance metrics) are measured based on the average of the high and low trading price of our stock on the grant date. Restricted stock awards primarily vest either at the end of a three year service period, or on a graded-vesting basis of one-third at each anniversary date over a three year service period. The annual forfeiture rate for restricted stock awards ranges from 0% to 7.1% based on approximately ten years of our history for this type of award to various employee groups. Performance shares that vest based on operating income or operating cash flow metrics vest on a graded-vesting basis of one-third at each anniversary date over a three year service period and no forfeiture rate is assumed. Performance shares that vest based on internal metrics vest at the end of a three year performance period and an annual forfeiture rate of 5.2% is assumed. Expense for restricted stock units is recorded immediately as these awards vest immediately. Restricted stock units are granted only to our directors and no forfeiture rate is assumed.

We grant another type of performance share award to executive employees that vest at the end of a three year performance period based on the comparative performance of our stock measured against sixteen other companies in our peer group. Depending on our performance, an aggregate of up to 100% of the fair market value of a share of our stock may be payable in common stock plus up to an additional 100% of the fair market value of a share of our stock may be payable in cash. These awards are accounted for by bifurcating the equity and liability components. A Monte Carlo model is used to value the liability component as well as the equity portion of the certain awards on the date of grant. The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for one and two year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the reporting period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including us. The paired returns in the correlation matrix ranged from approximately 52% to approximately 86% for us and our peer group. The expected dividend is calculated using our annual dividends paid ($0.12 per share for 2009) divided by the December 31, 2009 closing price of our stock ($43.59). Based on these inputs discussed above, a ranking was projected identifying our rank relative to the peer group for each award period. No forfeiture rate is assumed for this type of award. Expense related to these awards can be volatile based on our comparative ranking at the end of each quarter.

We used the shortcut approach to derive our initial windfall tax benefit pool. We chose to use a one-pool approach which combines all awards granted to employees, including non-employee directors.

On January 16, 2008, our Board of Directors adopted a Supplemental Employee Incentive Plan. The plan was intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event our common stock reached specified trading prices. The bonus payout of a minimum of 50% of an employee's base salary was triggered if, for any 20 trading days (which need not be consecutive) that fell within a period of 60 consecutive trading days occurring on or before November 1, 2011, the closing price per share of our common stock equaled or exceeded the final price goal of $60 per share. The plan also provided that an interim distribution of 10% of an employee's base salary would be paid to eligible employees upon achieving the interim price goal of $50 per share prior to December 31, 2009.

On the January 16, 2008 adoption date of the plan, our closing stock price was $40.71. On April 8, 2008 and subsequently on June 2, 2008, we achieved the interim and final target goals and total distributions of $15.7 million were paid in 2009. No further distributions will be made under this plan.

On July 24, 2008, our Board of Directors adopted a second Supplemental Employee Incentive Plan ("Plan II"). Plan II is similar to the January 2008 Supplemental Incentive Plan; however, the final target is that the closing price per share of our common stock must equal or exceed the price goal of $105 per share on or before June 20, 2012. Under Plan II, each eligible employee may receive (upon approval by the Compensation Committee) a distribution of 50% of his or her base salary (or 30% of base salary if we paid interim distributions upon the achievement of the interim price goal discussed below). Plan II provides that a distribution of 20% of an eligible employee's base salary upon achieving the interim price goal of $85 per share on or before June 30, 2010. The Compensation Committee can increase the 50% or 20% payment as it applies to any employee. Payments under this plan will partially be paid within 15 business days after achieving the target and the remaining portion will be paid based on a separate payment date as described in Plan II.

These awards under both plans discussed above have been accounted for as liability awards under ASC 718. The total expense for 2009 and 2008 was $1.2 million and $15.9 million, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations. For further information regarding the supplemental employee incentive plans and our other stock-based compensation awards, please refer to Note 9 of the Notes to the Consolidated Financial Statements.

OTHER ISSUES AND CONTINGENCIES

Regulations. Our operations are subject to various types of regulation by federal, state and local authorities. See "Regulation of Oil and Natural Gas Exploration and Production," "Natural Gas Marketing, Gathering and

Transportation," "Federal Regulation of Petroleum" and "Environmental Regulations" in the "Other Business Matters" section of Item 1 for a discussion of these regulations.

Restrictive Covenants. Our ability to incur debt and to make certain types of investments is subject to certain restrictive covenants in our various debt instruments. Among other requirements, our revolving credit agreement and our senior notes specify a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. In addition, we are required to maintain an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.5 to 1.0 and a current ratio of 1.0 to 1.0. Our senior notes require us to maintain a ratio of cash and proved reserves to indebtedness and other liabilities of 1.5 to 1.0. At December 31, 2009, we were in compliance in all material respects with all restrictive covenants on both the revolving credit agreement and notes. In the unforeseen event that we fail to comply with these covenants, we may apply for a temporary waiver with the lender, which, if granted, would allow us a period of time to remedy the situation. See further discussion in "Capital Resources and Liquidity."

Operating Risks and Insurance Coverage. Our business involves a variety of operating risks. See "Risk Factors—We face a variety of hazards and risks that could cause substantial financial losses" in Item 1A. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. The occurrence of any of these events not fully covered by insurance could have a material adverse effect on our financial position and results of operations. The costs of these insurance policies are somewhat dependent on our historical claims experience and also the areas in which we choose to operate.

Commodity Pricing and Risk Management Activities. Our revenues, operating results, financial condition and ability to borrow funds or obtain additional capital depend substantially on prevailing prices for natural gas and, to a lesser extent, oil. Declines in oil and gas prices may have a material adverse effect on our financial condition, liquidity, ability to obtain financing and operating results. Lower oil and gas prices also may reduce the amount of oil and gas that we can produce economically. Historically, oil and gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile. Depressed prices in the future would have a negative impact on our future financial results. In particular, substantially lower prices would significantly reduce revenue and could potentially trigger an impairment under ASC 360, "Property, Plant, and Equipment." Because our reserves are predominantly natural gas, changes in natural gas prices may have a particularly large impact on our financial results.

The majority of our production is sold at market responsive prices. Generally, if the related commodity index falls, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. However, management may mitigate this price risk on all or a portion of our anticipated production with the use of derivative financial instruments. Most recently, we have used financial instruments such as price collars and swap arrangements to reduce the impact of declining prices on our revenue. Under both arrangements, there is also a risk that the movement of index prices may result in our inability to realize the full benefit of an improvement in market conditions.

Settlement of Dispute. In December 2008, we settled a dispute with a third party and as a result recorded a gain of $51.9 million (approximately $32.5 million after-tax). The dispute involved the propriety of possession of our intellectual property by a third party. The settlement was comprised of $20.2 million in cash paid by the third party to us and $31.7 million related to the fair value of unproved property rights transferred by the third party to us. The fair market value of the unproved property rights was determined based on observable market costs and conditions over a recent time period. Values were pro-rated by property based on the primary term remaining on the properties.

Recently Adopted Accounting Standards

In July 2009, the Financial Accounting Standards Board (FASB) issued ASC 105, "Generally Accepted Accounting Principles," establishing the accounting standards codification and the hierarchy of generally accepted accounting principles (GAAP) as the sole source of authoritative non-governmental U.S. GAAP. The Codification was not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will now differ from what was previously being used in practice. Authoritative literature is now referenced by topic rather than by type of standard. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. The FASB now communicates new accounting standards by issuing an Accounting Standards Update (ASU). All guidance in the Codification has an equal level of authority. ASC 105 is effective for financial statements that cover interim and annual periods ending after September 15, 2009, and supersedes all accounting standards in U.S. GAAP, aside from those issued by the SEC. There was no impact on our financial position, results of operations or cash flows as a result of the Codification.

In February 2008, the FASB issued an amendment to ASC 820, "Fair Value Measurements and Disclosures," which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with ASC 820. Effective January 1, 2009, we applied these amendments of ASC 820 discussed above and there was no material impact on our financial statements except for our impairment of oil and natural gas properties. For further information, please refer to Note 2 and Note 11 of the Notes to the Consolidated Financial Statements.

Effective January 1, 2009, we adopted amendments that the FASB made to ASC 260, "Earnings Per Share," regarding determining whether instruments granted in share-based payment transactions are participating securities. The adoption of these amendments did not have a material impact on our financial statements. For further information, please refer to Note 12 of the Notes to the Consolidated Financial Statements.

In March 2008, the FASB amended the disclosure requirements prescribed in ASC 815, "Derivatives and Hedging." We adopted these amendments as of January 1, 2009. The principal impact was to require the expansion of our disclosure regarding our derivative instruments. For further information, please refer to "Derivative Instruments and Hedging Activity" in Note 11 of the Notes to the Consolidated Financial Statements.

In April 2009, the FASB amended guidance in ASC 820 regarding determining fair value when the volume and level of activity for an asset or liability has significantly decreased and identifying transactions that are not orderly. If an entity determines that either the volume or level of activity for an asset or liability has significantly decreased from normal conditions, or that price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The objective in fair value measurement remains unchanged from what is prescribed in ASC 820 and should be reflective of the current exit price. Disclosures in interim and annual periods must include inputs and valuation techniques used to measure fair value, along with any changes in valuation techniques and related inputs during the period. In addition, disclosures for debt and equity securities must be provided on a more disaggregated basis. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on our financial position, results of operations or cash flows.

In April 2009, the FASB amended ASC 825, "Financial Instruments," to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity's financial instruments that are not otherwise reported at fair value. These amendments became effective for interim reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. There was no material impact on our financial position, results of operations or cash flows as a result of the adoption. For further information, please refer to Note 11 of the Notes to the Consolidated Financial Statements.

In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities in ASC 320, "Investments—Debt and Equity Securities," to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. There were no amendments made to the recognition and measurement guidance for equity securities, but a new method of recognizing and reporting for debt securities was established. Disclosure requirements for impaired debt and equity securities have been expanded significantly and are now required quarterly, as well as annually. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on our financial position, results of operations or cash flows. Comparative disclosures are only required for periods ending after the initial adoption.

In June 2009, the FASB amended ASC 855, "Subsequent Events," to require entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being "available to be issued" was introduced. These amendments became effective for interim and annual periods ending after June 15, 2009 and did not have any impact on our financial position, results of operations or cash flows.

In August 2009, the FASB issued ASU No. 2009-05, "Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value," which provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. ASU No. 2009-05 specifies that in cases where a quoted price in an active market is not available, a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Valuation methods discussed include using an income approach, such as a present value technique, or a market approach based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. Entities are not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of the liability. ASU No. 2009-05 is codified in ASC 820-10 and is effective for the first reporting period (including interim periods) beginning after issuance. There was no impact on our financial position, results of operations or cash flows as a result of the adoption of ASU No. 2009-05. For further information, please refer to Note 11 of the Notes to the Consolidated Financial Statements.

In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which has been phased out. Release No. 33-8995 is intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 are required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The adoption of Release No. 33-8995 resulted in a downward revision to our proved reserves. For further information, please refer to the Supplemental Oil and Gas Information in the Notes to the Consolidated Financial Statements.

In January 2010, the FASB issued ASU No. 2010-03, "Oil and Gas Reserve Estimation and Disclosures," in order to align the oil and gas reserve estimation and disclosure requirements of "Extractive Activities —Oil and Gas" (Topic 932) with the requirements in the SEC's final rule, "Modernization of the Oil and Gas Reporting Requirements" issued in December 2008. The amendments to Topic 932 are effective for annual reporting periods ending on or after December 31, 2009.

In December 2008, the FASB issued an amendment to ASC 715-20, "Compensation – Retirement Benefits – Defined Benefit Plans – General," which requires enhanced disclosures regarding company benefit plans. Disclosure regarding plan assets should include discussion about how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure plan assets and significant concentrations of risk within plan assets. These amendments to ASC 715-20 are effective for fiscal years ending after December 15, 2009, and earlier application is permitted. Prior year periods presented for comparative purposes are not required to comply. These amendments to ASC 715-20 did not have a material impact on our financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

In January 2010, the FASB issued ASU No. 2010-06, "Improving Disclosures about Fair Value Measurements," which amends ASC 820-10-50 to require new disclosures concerning (1) transfers into and out of Levels 1 and 2 of the fair value measurement hierarchy, and (2) activity in Level 3 measurements. In addition, ASU No. 2010-06 clarifies certain existing disclosure requirements regarding the level of disaggregation and inputs and valuation techniques. Finally, ASU No. 2010-06 makes conforming amendments to the guidance on employers' disclosures about postretirement benefit plans assets (FASB ASC 715-20-50). ASU No. 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. We are currently evaluating the impact ASU No. 2010-06 may have on our financial position, results of operations or cash flows.

Forward-Looking Information

The statements regarding future financial and operating performance and results, market prices, future hedging activities, and other statements that are not historical facts contained in this report are forward-looking statements. The words "expect," "project," "estimate," "believe," "anticipate," "intend," "budget," "plan," "forecast," "predict," "may," "should," "could," "will" and similar expressions are also intended to identify forward-looking statements. Such statements involve risks and uncertainties, including, but not limited to, market factors, market prices (including regional basis differentials) of natural gas and oil, results for future drilling and marketing activity, future production and costs and other factors detailed herein and in our other Securities and Exchange Commission filings. See "Risk Factors" in Item 1A for additional information about these risks and uncertainties. Should one or more of these risks or uncertainties materialize, or should underlying assumptions prove incorrect, actual outcomes may vary materially from those indicated.

RESULTS OF OPERATIONS

2009 and 2008 Compared

We reported net income for 2009 of $148.3 million, or $1.43 per share. During 2008, we reported net income of $211.3 million, or $2.10 per share. Net income decreased in 2009 by $63.0 million, primarily due to a decrease in operating revenues, an increase in depreciation, depletion and amortization, an increase in interest expense, an increase in exploration expense and an increase in direct operations. Also impacting net income in 2008 was a gain on the settlement of a dispute. These decreases and increases were partially offset by decreased operating and income tax expenses, decreased brokered natural gas cost, decreased impairments of oil and gas properties and other assets, decreased impairments of unproved properties, decreased general and administrative expense and loss on sale of assets. Operating revenues decreased by $66.5 million largely due to decreases in brokered natural gas and natural gas production revenues. Operating expenses decreased by $33.1 million between periods due primarily to decreases in impairments of unproved properties and oil and gas properties, brokered natural gas costs, taxes other than income and general and administrative expenses, partially offset by increased depreciation, depletion and amortization, exploration expense and direct operations. In addition, net income was impacted in 2009 by higher interest expense, decreased income tax expense and, to a lesser extent, loss on sale of assets. Income tax expense was lower in 2009 as a result of a decrease in operating income, as discussed above, and a decrease in the effective tax rate. The decrease in the effective tax rate is primarily due to an overall reduction in state deferred tax liabilities and tax benefits associated with foreign tax credits.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $7.47 per Mcf for 2009 compared to $8.39 per Mcf for 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by $3.80 per Mcf in 2009 and by $0.20 per Mcf in 2008. The following table excludes the unrealized loss from the change in fair value of our basis swaps of $2.0 million for the year ended December 31, 2009, which has been included within Natural Gas Production Revenues in the Consolidated Statement of Operations. There was no revenue impact from the unrealized change in natural gas derivative fair value for the year ended December 31, 2008.

	Year Ended December 31,		Variance	
	2009	2008	Amount	Percent
Natural Gas Production *(Mmcf)*				
North	**48,154**	39,715	8,439	21%
South	**48,802**	46,568	2,234	5%
Canada	**958**	4,142	(3,184)	(77%)
Total Company	**97,914**	90,425	7,489	8%
Natural Gas Production Sales Price *($/Mcf)*				
North	**$ 6.59**	$ 7.95	$ (1.36)	(17%)
South	**$ 8.42**	$ 8.84	$ (0.42)	(5%)
Canada	**$ 3.72**	$ 7.62	$ (3.90)	(51%)
Total Company	**$ 7.47**	$ 8.39	$ (0.92)	(11%)
Natural Gas Production Revenue *(In thousands)*				
North	**$ 317,456**	$ 315,582	$ 1,874	1%
South	**410,674**	411,616	(942)	0%
Canada	**3,558**	31,557	(27,999)	(89%)
Total Company	**$ 731,688**	$ 758,755	$ (27,067)	(4%)
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ (65,182)**			
South	**(20,687)**			
Canada	**(3,737)**			
Total Company	**$ (89,606)**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	**$ 67,056**			
South	**19,745**			
Canada	**(24,262)**			
Total Company	**$ 62,539**			

The decrease in Natural Gas Production Revenue of $27.1 million, excluding the impact of the unrealized gains and losses discussed above, is almost entirely due to the sale of our Canadian properties, a decrease in realized natural gas prices in all regions was essentially offset by an increase in natural gas production. This increase in natural gas production was primarily a result of increased production in the North region associated with the initiation of production in Susquehanna County, Pennsylvania in the third quarter of 2008 and increased drilling in the Marcellus Shale prospect in Susquehanna County as well as increased natural gas production in the South region associated with the properties we acquired in east Texas in August 2008 and drilling in the Angie field. Partially offsetting these production gains were decreases in production in Canada due to the sale of substantially all of our Canadian properties in April 2009.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,				Variance		
	2009		2008		Amount		Percent
Sales Price *($/Mcf)*	**$**	**5.95**	$	10.39	$	(4.44)	(43%)
Volume Brokered *(Mmcf)*	**x**	**12,656**	x	10,996		1,660	15%
Brokered Natural Gas Revenues *(In thousands)*	**$**	**75,283**	$	114,220			
Purchase Price *($/Mcf)*	**$**	**5.30**	$	9.14	$	(3.84)	(42%)
Volume Brokered *(Mmcf)*	**x**	**12,656**	x	10,996		1,660	15%
Brokered Natural Gas Cost *(In thousands)*	**$**	**67,030**	$	100,449			
Brokered Natural Gas Margin *(In thousands)*	**$**	**8,253**	$	13,771	$	(5,518)	(40%)

(In thousands)		
Sales Price Variance Impact on Revenue	**$**	**(56,185)**
Volume Variance Impact on Revenue		**17,248**
	$	**(38,937)**

(In thousands)		
Purchase Price Variance Impact on Purchases	**$**	**48,592**
Volume Variance Impact on Purchases		**(15,173)**
	$	**33,419**

The decreased brokered natural gas margin of $5.5 million is a result of a decrease in sales price that outpaced the decrease in purchase price, partially offset by an increase in volumes brokered.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price, including the realized impact of derivative instruments, was $85.52 per Bbl for 2009 compared to $89.11 per Bbl for 2008. These prices include the realized impact of derivative instrument settlements, which increased the price by $28.25 per Bbl in 2009 and decreased the price by $6.33 per Bbl in 2008. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value in 2009 or 2008.

	Year Ended December 31,		Variance	
	2009	2008	Amount	Percent
Crude Oil Production *(Mbbl)*				
North	**109**	113	(4)	(4%)
South	**703**	648	55	8%
Canada	**6**	21	(15)	(71%)
Total Company	**818**	782	36	5%
Crude Oil Sales Price *($/Bbl)*				
North	**$ 54.11**	$ 93.62	$ (39.51)	(42%)
South	**$ 90.86**	$ 88.46	$ 2.40	3%
Canada	**$ 33.97**	$ 85.08	$ (51.11)	(60%)
Total Company	**$ 85.52**	$ 89.11	$ (3.59)	(4%)
Crude Oil Revenue *(In thousands)*				
North	**$ 5,875**	$ 10,553	$ (4,678)	(44%)
South	**63,835**	57,331	6,504	11%
Canada	**226**	1,827	(1,601)	(88%)
Total Company	**$ 69,936**	$ 69,711	$ 225	0%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (4,290)**			
South	**1,639**			
Canada	**(315)**			
Total Company	**$ (2,966)**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
North	**$ (388)**			
South	**4,865**			
Canada	**(1,286)**			
Total Company	**$ 3,191**			

The increase in crude oil production, partially offset by a decrease in realized crude oil prices in the North and Canada resulted in a net revenue increase of $0.2 million. The increase in crude oil production was primarily the result of increased production in the South region associated with the properties we acquired in the east Texas acquisition in August 2008 and an increase related to Pettet development in the Angie field, partially offset by a decrease in production in Canada due to the sale of substantially all of our Canadian properties in April 2009.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Year Ended December 31,			
	2009		2008	
(In thousands)	**Realized**	**Unrealized**	Realized	Unrealized
Operating Revenues - Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 371,915**	**$ -**	$ 17,972	$ -
Crude Oil	**23,112**	**-**	(4,951)	-
Total Cash Flow Hedges	**395,027**	**-**	13,021	-
Other Derivative Financial Instruments				
Natural Gas Basis Swaps	**-**	**(1,954)**	-	-
Total Other Derivative Financial Instruments	**-**	**(1,954)**	-	-
Total Cash Flow Hedges and Other Derivative Financial Instruments	**$ 395,027**	**$ (1,954)**	$ 13,021	$ -

We are exposed to market risk on derivative instruments to the extent of changes in market prices of natural gas and oil. However, the market risk exposure on these derivative contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity. Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. We do not anticipate any material impact on our financial results due to non-performance by third parties. Our primary derivative contract counterparties are Bank of Montreal, BNP Paribas, JPMorgan Chase, Key Bank and Morgan Stanley.

Operating Expenses

Total costs and expenses from operations decreased by $33.1 million in 2009 from 2008. The primary reasons for this fluctuation are as follows:

- Depreciation, Depletion and Amortization increased by $35.9 million from 2008 to 2009. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas and oil production volumes, including the east Texas acquisition in August 2008.

- Brokered Natural Gas Cost decreased by $33.4 million from 2008 to 2009. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.

- Taxes Other Than Income decreased by $21.9 million from 2008 to 2009 due to lower production taxes as a result of lower average natural gas and crude oil prices.

- Exploration expense increased by $19.6 million from 2008 to 2009 primarily due to higher charges for idle contract rigs and higher dry hole and geological and geophysical costs.

- Impairment of Oil & Gas Properties and Other Assets decreased by $18.1 million from 2008 to 2009. Impairments in 2009 consisted of approximately $12.0 million in the Fossil Federal field in San Miguel County, Colorado resulting from lower well performance and $5.6 million in the Beaurline field in Hidalgo County, Texas resulting from lower well performance..

- Impairment of Unproved Properties decreased by $11.5 million from 2008 to 2009, primarily due to the $17.0 million impairment of Mississippi, Montana and North Dakota leases in 2008 offset by increased lease acquisition costs incurred in several exploratory and developmental areas in the North and in east Texas as well as the amortization of undeveloped costs associated with the east Texas acquisition in August 2008.

- General and Administrative expenses decreased by $5.8 million from 2008 to 2009. This is primarily due to decreased stock compensation expense largely related to a reduction in supplemental employee compensation expense of $14.7 million, partially offset by an increase in performance share award expense of $5.5 million and an increase in pension expense related to our qualified pension plan.

- Direct Operations expenses increased by $2.1 million from 2008 to 2009 primarily due to higher personnel and labor expenses, increased severance and employee relocation costs associated with the reorganization of operations and higher compressor and outside operated properties charges.

Interest Expense, Net

Interest expense, net increased by $22.6 million from 2008 to 2009 primarily due to increased interest expense related to the $492 million principal amount of debt we issued in our July and December 2008 private placements. Weighted-average borrowings under our credit facility based on daily balances were approximately $166 million during 2009 compared to approximately $172 million during 2008. The weighted-average effective interest rate on the credit facility decreased to approximately 4.0% during 2009 compared to approximately 4.8% during 2008.

Income Tax Expense

Income tax expense decreased by $49.4 million due to a decrease in our pre-tax income. The effective tax rates for 2009 and 2008 were 33.6% and 37.0%, respectively. The decrease in the effective tax rate is primarily due to an overall reduction in state deferred tax liabilities and tax benefits associated with foreign tax credits.

2008 and 2007 Compared

We reported net income for the year ended December 31, 2008 of $211.3 million, or $2.10 per share. During 2007, we reported net income of $167.4 million, or $1.73 per share. This increase of $43.9 million in net income was primarily due to an increase in operating revenues and gains on asset sales and settlements, partially offset by increased operating, interest and income tax expenses. Operating revenues increased by $213.6 million, largely due to increases in both natural gas production revenues and brokered natural gas revenues and crude oil and condensate revenues. Operating expenses increased by $155.9 million between periods due to increases in all categories of operating expenses other than exploration expense. In addition, net income was impacted by an increase in gain on sale of assets and gain on settlement of dispute of $39.6 million as well as an increase in expenses of $53.4 million resulting from a combination of increased income tax expense and interest and other expenses. Income tax expense was higher in 2008 as a result of higher income before income taxes in 2008 compared to 2007, in addition to an increase in the effective tax rate.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $8.39 per Mcf for 2008 compared to $7.23 per Mcf for 2007. These prices include the realized impact of derivative instrument settlements, which increased the price by $0.20 per Mcf in 2008 and by $0.99 per Mcf in 2007. There was no revenue impact from the unrealized change in natural gas derivative fair value for the years ended December 31, 2008 and 2007.

	Year Ended December 31,		Variance	
	2008	2007	Amount	Percent
Natural Gas Production *(Mmcf)*				
North	39,715	38,784	931	2%
South	46,568	37,766	8,802	23%
Canada	4,142	3,925	217	6%
Total Company	90,425	80,475	9,950	12%
Natural Gas Production Sales Price *($/Mcf)*				
North	$ 7.95	$ 7.02	$ 0.93	13%
South	$ 8.84	$ 7.63	$ 1.21	16%
Canada	$ 7.62	$ 5.47	$ 2.15	39%
Total Company	$ 8.39	$ 7.23	$ 1.16	16%
Natural Gas Production Revenue *(In thousands)*				
North	$ 315,582	$ 272,140	$ 43,442	16%
South	411,616	288,034	123,582	43%
Canada	31,557	21,466	10,091	47%
Total Company	$ 758,755	$ 581,640	$ 177,115	30%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	$ 35,678			
South	55,222			
Canada	8,906			
Total Company	$ 99,806			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
North	$ 7,764			
South	68,360			
Canada	1,185			
Total Company	$ 77,309			

The increase in Natural Gas Production Revenue of $177.1 million is due to the increase in realized natural gas sales prices in addition to an increase in natural gas production. Natural gas production in the South region increased due to increased production in the Minden field, largely due to the properties we acquired in east Texas in August 2008, as well as increased drilling in the County Line field. In addition, natural gas production increased in the North region associated with an increase in the drilling program and increased drilling activity in West Virginia and northeastern Pennsylvania. Canada increased due to drilling in the Hinton field.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,				Variance		
	2008		2007		Amount		Percent
Sales Price *($/Mcf)*	$	10.39	$	8.40	$	1.99	24%
Volume Brokered *(Mmcf)*	x	10,996	x	11,101		(105)	(1%)
Brokered Natural Gas Revenues *(In thousands)*	$	114,220	$	93,215			
Purchase Price *($/Mcf)*	$	9.14	$	7.37	$	1.77	24%
Volume Brokered *(Mmcf)*	x	10,996	x	11,101		(105)	(1%)
Brokered Natural Gas Cost *(In thousands)*	$	100,449	$	81,819			
Brokered Natural Gas Margin *(In thousands)*	$	13,771	$	11,396	$	2,375	21%

(In thousands)		
Sales Price Variance Impact on Revenue	$	21,882
Volume Variance Impact on Revenue		(882)
	$	21,000

(In thousands)		
Purchase Price Variance Impact on Purchases	$	(19,399)
Volume Variance Impact on Purchases		774
	$	(18,625)

The increased brokered natural gas margin of $2.4 million is a result of an increase in sales price that outpaced the increase in purchase price, partially offset by a decrease in the volumes brokered in 2008 over 2007.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price was $89.11 per Bbl for 2008 compared to $67.16 per Bbl for 2007. These prices include the realized impact of derivative instrument settlements, which decreased the price by $6.33 per Bbl in 2008 and by $0.97 per Bbl in 2007. There was no revenue impact from the unrealized change in crude oil and condensate derivative fair value in 2008 or 2007.

	Year Ended December 31,		Variance	
	2008	2007	Amount	Percent
Crude Oil Production *(Mbbl)*				
North	113	133	(20)	(15%)
South	648	672	(24)	(4%)
Canada	21	18	3	17%
Total Company	782	823	(41)	(5%)
Crude Oil Sales Price *($/Bbl)*				
North	$ 93.62	$ 67.37	$ 26.25	39%
South	$ 88.46	$ 67.30	$ 21.16	31%
Canada	$ 85.08	$ 59.96	$ 25.12	42%
Total Company	$ 89.11	$ 67.16	$ 21.95	33%
Crude Oil Revenue *(In thousands)*				
North	$ 10,553	$ 8,981	$ 1,572	18%
South	57,331	45,210	12,121	27%
Canada	1,827	1,052	775	74%
Total Company	$ 69,711	$ 55,243	$ 14,468	26%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
North	$ 2,959			
South	13,714			
Canada	600			
Total Company	$ 17,273			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
North	$ (1,387)			
South	(1,593)			
Canada	175			
Total Company	$ (2,805)			

The increase in realized crude oil prices, partially offset by a decrease in production, resulted in a net revenue increase of $14.4 million. The decrease in oil production is mainly the result of a natural decline in crude oil production in the North and South regions.

Impact of Derivative Instruments on Operating Revenues

The following table reflects the realized impact of cash settlements and the net unrealized change in fair value of derivative instruments:

	Year Ended December 31,			
	2008		2007	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues - Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	$ 17,972	$ -	$ 79,838	$ -
Crude Oil	(4,951)	-	(796)	-
Total Cash Flow Hedges	$ 13,021	$ -	$ 79,042	$ -

Operating Expenses

Total costs and expenses from operations increased by $155.9 million in 2008 from 2007. The primary reasons for this fluctuation are as follows:

- Depreciation, Depletion and Amortization increased by $41.5 million from 2007 to 2008. This is primarily due to the impact on the DD&A rate of higher capital costs and higher natural gas production volumes, including the east Texas acquisition.

- Impairment of Oil & Gas Properties and Other Assets increased by $31.1 million from 2007 to 2008 primarily related to impairments of approximately $28.3 million in the Trawick field in Rusk County, Texas in the South region resulting from a decline in natural gas prices and higher well costs as well as $3.0 million in the Corral Creek field in Washakie County, Wyoming in the North region resulting from lower than expected performance from the two well field.

- General and Administrative expenses increased by $23.4 million from 2007 to 2008. This is primarily due to increased stock compensation expense related to the payouts of our supplemental employee incentive plan bonuses ($15.7 million) as well as increased expense related to our performance share awards ($5.1 million).

- Impairment of Unproved Properties increased by $22.5 million from 2007 to 2008, primarily due to increased lease acquisition costs in several exploratory and developmental areas, as well as a $17.0 million charge for the impairment of three exploratory oil and gas prospects located in Mississippi, Montana and North Dakota. These prospects were impaired as a result of the significant decline in commodity prices in the fourth quarter of 2008 and abandonment of our exploration plans.

- Brokered Natural Gas Cost increased by $18.6 million from 2007 to 2008. See the preceding table titled "Brokered Natural Gas Revenue and Cost" for further analysis.

- Direct Operations expenses increased by $14.6 million from 2007 to 2008 primarily due to higher personnel and labor expenses, maintenance expenses, treating, compressor, pipeline and workover costs and vehicle and fuel expenses, partially offset by lower insurance costs.

- Taxes Other Than Income increased by $12.8 million from 2007 to 2008 due to higher production taxes as a result of higher operating revenues and, to a lesser extent, higher ad valorem taxes, partially offset by lower franchise taxes.

- Exploration expense decreased by $8.6 million from 2007 to 2008 primarily due to fewer dry holes, partially offset by increased geological and geophysical costs.

Interest Expense, Net

Interest expense, net increased by $19.2 million in 2008 compared to 2007 primarily due to increased interest expense related to the debt we issued in our July and December 2008 private placements and, to a lesser extent, higher average credit facility borrowings, offset in part by a lower weighted-average interest rate on our revolving credit facility borrowings and lower outstanding borrowings on our 7.19% fixed rate debt. Weighted-average borrowings under our credit facility based on daily balances were approximately $172 million during 2008 compared to approximately $52 million during 2007. The weighted-average effective interest rate on the credit facility decreased to 4.8% during 2008 from 7.2% during 2007.

Income Tax Expense

Income tax expense increased by $34.2 million due to a comparable increase in our pre-tax income. The effective tax rates for 2008 and 2007 were 37.0% and 35.0%, respectively. The increase in the effective tax rate is primarily due to a one time benefit for state taxes in 2007 of approximately $2.8 million attributable to favorable treatment of the gain from the sale of south Louisiana properties in 2006 and a reduction in special deductions in 2008.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risk

Our primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

The debt and equity markets have recently experienced unfavorable conditions, which may affect our ability to access those markets. As a result of the volatility and disruption in the capital markets and our increased level of borrowings, we may experience increased costs associated with future borrowings and debt issuances. At this time, we do not believe our liquidity has been materially affected by the recent market events. We will continue to monitor events and circumstances surrounding each of our lenders in our revolving credit facility.

Derivative Instruments and Hedging Activity

Our hedging strategy is designed to reduce the risk of price volatility for our production in the natural gas and crude oil markets. A hedging committee that consists of members of senior management oversees our hedging activity. Our hedging arrangements apply to only a portion of our production and provide only partial price protection. These hedging arrangements limit the benefit to us of increases in prices, but offer protection in the event of price declines. Further, if our counterparties defaulted, this protection might be limited as we might not receive the benefits of the hedges. Please read the discussion below as well as Note 11 of the Notes to the Consolidated Financial Statements for a more detailed discussion of our hedging arrangements.

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. Our credit agreement restricts our ability to enter into commodity hedges other than to hedge or mitigate risks to which we have actual or projected exposure or as permitted under our risk management policies and not subjecting us to material speculative risks. At December 31, 2009, we had 12 cash flow hedges open: 11 natural gas price swap arrangements and one crude oil price swap arrangement. During 2009, we entered into six new derivative contracts covering anticipated natural gas production for 2012. These natural gas basis swaps did not qualify for hedge accounting under ASC 815. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

As of December 31, 2009, we had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price		Volume		Contract Period	Net Unrealized Gain (In thousands)	
Derivatives designated as Hedging Instruments under ASC 815								
Natural Gas	Swap	$9.30	per Mcf	35,856	Mmcf	2010	$	98,906
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010		15,564
							$	**114,470**
Derivatives not qualifying as Hedging Instruments under ASC 815								
Natural Gas	Basis Swap	$(0.27)	per Mcf	16,123	Mmcf	2012		(2,003)
							$	**112,467**

The amounts set forth under the net unrealized gain column in the tables above represent our total unrealized gain position at December 31, 2009 and do not include the impact of nonperformance risk. Also impacting the total unrealized net gain (reflecting the net receivable position) in accumulated other comprehensive income / (loss) in the Consolidated Balance Sheet is a reduction of $0.2 million related to our assessment of our counterparties' nonperformance risk. This risk was primarily evaluated by reviewing credit default swap spreads for the various financial institutions in which we have derivative transactions.

From time to time, we enter into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under these price swaps, we receive a fixed price on a notional quantity of natural gas or crude oil in exchange for paying a variable price based on a market-based index, such as the NYMEX gas and crude oil futures.

During 2009, four natural gas price swaps covered 16,079 Mmcf, or 16%, of our 2009 gas production at an average price of $12.18 per Mcf.

We had one crude oil price swap covering 365 Mbbl, or 45%, of our 2009 oil production at a price of $125.25 per Bbl.

From time to time, we enter into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of our production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, we pay the counterparty. If the index price falls below the floor price, the counterparty pays us. During 2009, 14 natural gas price collars covered 47,253 Mmcf, or 48%, of our 2009 gas production, with a weighted-average floor of $9.40 per Mcf and a weighted-average ceiling of $12.39 per Mcf.

We are exposed to market risk on these open contracts, to the extent of changes in market prices of natural gas and crude oil. However, the market risk exposure on these hedged contracts is generally offset by the gain or loss recognized upon the ultimate sale of the commodity that is hedged.

The preceding paragraphs contain forward-looking information concerning future production and projected gains and losses, which may be impacted both by production and by changes in the future market prices of energy commodities. See "Forward-Looking Information" for further details.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the year- end market rate. The credit spread is our default or repayment risk. The credit spread (premium or discount) is determined by comparing our fixed-rate notes to new issues (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair values of all of the fixed-rate notes, excluding the credit facility, are based on interest rates currently available to us. The credit facility approximates fair value because this instrument bears interest at rates based on current market rates.

We use available marketing data and valuation methodologies to estimate the fair value of debt.

Long-Term Debt

	December 31, 2009		December 31, 2008	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Long-Term Debt	**$ 805,000**	**$ 863,559**	$ 867,000	$ 807,508
Current Maturities	**-**	**-**	(35,857)	(35,796)
Long-Term Debt, excluding Current Maturities	**$ 805,000**	**$ 863,559**	$ 831,143	$ 771,712

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of Cabot Oil & Gas Corporation:

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries (the "Company") at December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, 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, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements 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 11 to the consolidated financial statements, the Company changed the manner in which it accounts for and reports fair value measurements in 2008.

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

Houston, Texas
February 26, 2010

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF OPERATIONS

(In thousands, except per share amounts)	Year Ended December 31, **2009**	2008	2007
OPERATING REVENUES			
Natural Gas Production	**$ 729,734**	$ 758,755	$ 581,640
Brokered Natural Gas	**75,283**	114,220	93,215
Crude Oil and Condensate	**69,936**	69,711	55,243
Other	**4,323**	3,105	2,072
	879,276	945,791	732,170
OPERATING EXPENSES			
Brokered Natural Gas Cost	**67,030**	100,449	81,819
Direct Operations - Field and Pipeline	**93,985**	91,839	77,170
Exploration	**50,784**	31,200	39,772
Depreciation, Depletion and Amortization	**221,270**	185,403	143,951
Impairment of Unproved Properties	**29,990**	41,512	19,042
Impairment of Oil & Gas Properties and Other Assets (Note 2)	**17,622**	35,700	4,614
General and Administrative	**68,374**	74,185	50,775
Taxes Other Than Income	**44,649**	66,540	53,782
	593,704	626,828	470,925
Gain/(Loss) on Sale of Assets	**(3,303)**	1,143	13,448
Gain on Settlement of Dispute (Note 7)	**-**	51,906	-
INCOME FROM OPERATIONS	**282,269**	372,012	274,693
Interest Expense and Other	**58,979**	36,389	17,161
Income Before Income Taxes	**223,290**	335,623	257,532
Income Tax Expense	**74,947**	124,333	90,109
NET INCOME	**$ 148,343**	$ 211,290	$ 167,423
Basic Earnings Per Share	**$ 1.43**	$ 2.10	$ 1.73
Diluted Earnings Per Share	**$ 1.42**	$ 2.08	$ 1.71
Weighted-Average Common Shares Outstanding	**103,616**	100,737	96,978
Diluted Common Shares (Note 12)	**104,683**	101,726	98,130

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2009	December 31, 2008
ASSETS		
Current Assets		
Cash and Cash Equivalents	**$ 40,158**	$ 28,101
Accounts Receivable, Net (Note 3)	**80,362**	109,087
Income Taxes Receivable	**8,909**	526
Inventories (Note 3)	**27,990**	45,677
Current Derivative Contracts (Note 11)	**114,686**	264,660
Other Current Assets (Note 3)	**9,397**	12,500
Total Current Assets	**281,502**	460,551
Properties and Equipment, Net (Successful Efforts Method) (Note 2)	**3,358,199**	3,135,828
Long-Term Derivative Contracts (Note 11)	**-**	90,542
Investment in Equity Securities (Note 2)	**20,636**	-
Other Assets (Note 3)	**23,064**	14,743
	$ 3,683,401	$ 3,701,664
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities		
Accounts Payable (Note 3)	**$ 215,588**	$ 222,985
Current Portion of Long-Term Debt (Note 4)	**-**	35,857
Deferred Income Taxes	**35,104**	63,985
Income Taxes Payable	**-**	5,535
Accrued Liabilities (Note 3)	**58,049**	50,551
Total Current Liabilities	**308,741**	378,913
Long-Term Liability for Pension and Postretirement Benefits (Note 5)	**54,835**	54,714
Long-Term Debt (Note 4)	**805,000**	831,143
Deferred Income Taxes	**644,801**	599,106
Other Liabilities (Note 3)	**57,510**	47,226
Total Liabilities	**1,870,887**	1,911,102
Commitments and Contingencies (Note 7)		
Stockholders' Equity		
Common Stock:		
Authorized -- 240,000,000 Shares of $0.10 Par Value in 2009 and 120,000,000 Shares of $0.10 Par Value in 2008		
Issued -- 103,856,447 Shares and 103,561,268 Shares in 2009 and 2008, respectively	**10,386**	10,356
Additional Paid-in Capital	**705,569**	675,568
Retained Earnings	**1,057,472**	921,561
Accumulated Other Comprehensive Income (Note 13)	**42,436**	186,426
Less Treasury Stock, at Cost: (Note 9)		
202,200 Shares in 2009 and 2008, respectively	**(3,349)**	(3,349)
Total Stockholders' Equity	**1,812,514**	1,790,562
	$ 3,683,401	$ 3,701,664

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)	Year Ended December 31, 2009	2008	2007
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 148,343**	$ 211,290	$ 167,423
Adjustments to Reconcile Net Income to Cash Provided by Operating Activities:			
Depreciation, Depletion and Amortization	**221,270**	185,403	143,951
Impairment of Unproved Properties	**29,990**	41,512	19,042
Impairment of Oil & Gas Properties and Other Assets	**17,622**	35,700	4,614
Deferred Income Tax Expense	**101,815**	120,851	95,152
(Gain) / Loss on Sale of Assets	**3,303**	(1,143)	(13,448)
Gain on Settlement of Dispute	**-**	(31,706)	-
Exploration Expense	**50,784**	31,200	39,772
Unrealized Loss on Derivatives	**1,954**	-	-
Stock-Based Compensation Expense and Other	**29,559**	15,623	16,241
Changes in Assets and Liabilities:			
Accounts Receivable, Net	**28,725**	(3,928)	6,854
Income Taxes Receivable	**5,893**	34,521	14,456
Inventories	**17,687**	(18,324)	5,644
Other Current Assets	**3,103**	10,816	(14,908)
Other Assets	**(168)**	5,698	(29,795)
Accounts Payable and Accrued Liabilities	**(27,202)**	3,321	1,052
Income Taxes Payable	**(5,535)**	3,580	(1,281)
Other Liabilities	**699**	724	7,368
Stock-Based Compensation Tax Benefit	**(13,790)**	(10,691)	-
Net Cash Provided by Operating Activities	**614,052**	634,447	462,137
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(560,029)**	(817,440)	(553,229)
Acquisitions	**(394)**	(605,748)	(3,982)
Proceeds from Sale of Assets	**80,180**	2,099	7,061
Exploration Expense	**(50,784)**	(31,200)	(39,772)
Net Cash Used in Investing Activities	**(531,027)**	(1,452,289)	(589,922)
CASH FLOWS FROM FINANCING ACTIVITIES			
Borrowings from Debt	**105,000**	892,000	175,000
Repayments of Debt	**(167,000)**	(375,000)	(65,000)
Net Proceeds from Sale of Common Stock	**83**	316,230	5,099
Stock-Based Compensation Tax Benefit	**13,790**	10,691	-
Dividends Paid	**(12,432)**	(12,073)	(10,670)
Capitalized Debt Issuance Costs	**(10,409)**	(4,403)	-
Net Cash (Used in) / Provided by Financing Activities	**(70,968)**	827,445	104,429
Net Increase / (Decrease) in Cash and Cash Equivalents	**12,057**	9,603	(23,356)
Cash and Cash Equivalents, Beginning of Period	**28,101**	18,498	41,854
Cash and Cash Equivalents, End of Period	**$ 40,158**	$ 28,101	$ 18,498

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands, except per share amounts)	Common Shares	Stock Par	Treaury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income / (Loss) [1]	Retained Earnings	Total
Balance at December 31, 2006	101,418	$ 10,142	5,205	$ (85,690)	$ 417,995	$ 37,160	$ 565,591	$ 945,198
Net Income	-	-	-	-	-	-	167,423	167,423
Exercise of Stock Options	619	62	-	-	5,005	-	-	5,067
Stock Amortization and Vesting	430	43	-	-	7,503	-	-	7,546
Stock Held in Rabbi Trust	214	21	-	-	(6,274)	-	-	(6,253)
Cash Dividends at $0.11 per Share	-	-	-	-	-	-	(10,670)	(10,670)
Other Comprehensive Income	-	-	-	-	-	(38,054)	-	(38,054)
Balance at December 31, 2007	102,681	$ 10,268	5,205	$ (85,690)	$ 424,229	$ (894)	$ 722,344	$ 1,070,257
Net Income	-	-	-	-	-	-	211,290	211,290
Exercise of Stock Options	328	33	-	-	2,692	-	-	2,725
Retirement of Treasury Stock	(5,003)	(500)	(5,003)	82,341	(81,841)	-	-	-
Tax Benefit of Stock-Based Compensation	-	-	-	-	10,691	-	-	10,691
Stock Amortization and Vesting	418	42	-	-	6,545	-	-	6,587
Stock Held in Rabbi Trust	64	6	-	-	(3,198)	-	-	(3,192)
Stock Issued for Drilling Company Acquisition	70	7	-	-	3,493	-	-	3,500
Issuance of Common Stock	5,003	500	-	-	312,957	-	-	313,457
Cash Dividends at $0.12 per Share	-	-	-	-	-	-	(12,073)	(12,073)
Other Comprehensive Income	-	-	-	-	-	187,320	-	187,320
Balance at December 31, 2008	103,561	$ 10,356	202	$ (3,349)	$ 675,568	$ 186,426	$ 921,561	$ 1,790,562
Net Income	-	-	-	-	-	-	148,343	148,343
Exercise of Stock Options and Stock Appreciation Rights	14	2	-	-	53	-	-	55
Tax Benefit of Stock-Based Compensation	-	-	-	-	13,790	-	-	13,790
Stock Amortization and Vesting	281	28	-	-	14,898	-	-	14,926
Sale of Stock Held in Rabbi Trust	-	-	-	-	1,260	-	-	1,260
Cash Dividends at $0.12 per Share	-	-	-	-	-	-	(12,432)	(12,432)
Other Comprehensive Income	-	-	-	-	-	(143,990)	-	(143,990)
Balance at December 31, 2009	**103,856**	**$ 10,386**	**202**	**$ (3,349)**	**$ 705,569**	**$ 42,436**	**$ 1,057,472**	**$ 1,812,514**

[1] *For further details on the components of Accumulated Other Comprehensive Income and Loss, refer to Note 13 of the Notes to the Consolidated Financial Statements.*

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

(In thousands)	Year Ended December 31, **2009**		2008		2007	
Net Income		**$ 148,343**		$ 211,290		$ 167,423
Other Comprehensive Income / (Loss), net of taxes						
Reclassification Adjustment for Settled Contracts, net of taxes of $147,048, $4,844 and $29,801, respectively		**(247,979)**		(8,177)		(49,241)
Changes in Fair Value of Hedge Positions, net of taxes of $(57,303), $(134,259) and $(1,777), respectively		**96,783**		226,692		2,555
Defined Benefit Pension and Postretirement Plans:						
Net Loss Arising During the Year, net of taxes of $1,773, $10,445 and $1,034, respectively	**$ (3,009)**		$ (17,629)		$ (1,733)	
Amortization of Net Obligation at Transition, net of taxes of $(236), $(234) and $(238), respectively	**396**		398		394	
Amortization of Prior Service Cost, net of taxes of $(267), $(373) and $(413), respectively	**450**		630		681	
Amortization of Net Loss, net of taxes of $(1,432), $(603) and $(483), respectively	**2,422**	**259**	1,020	(15,581)	799	141
Foreign Currency Translation Adjustment, net of taxes of $(4,116), $9,292 and $(5,072), respectively		**6,947**		(15,614)		8,491
Total Other Comprehensive Income / (Loss)		**(143,990)**		187,320		(38,054)
Comprehensive Income		**$ 4,353**		$ 398,610		$ 129,369

The accompanying notes are an integral part of these consolidated financial statements.

CABOT OIL & GAS CORPORATION

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation and Nature of Operations

Cabot Oil & Gas Corporation and its subsidiaries are engaged in the development, exploitation, exploration, production and marketing of natural gas and, to a lesser extent, crude oil and natural gas liquids. The Company also transports, stores, gathers and purchases natural gas for resale. The Company operates in one segment, natural gas and oil development, exploitation and exploration, exclusively within the continental United States. The Company's exploration activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. In April 2009, the Company sold substantially all of its assets located in Canada.

The consolidated financial statements contain the accounts of the Company and its subsidiaries after eliminating all significant intercompany balances and transactions.

In 2009, the Company restructured its operations by combining the Rocky Mountain and Appalachian areas to form the North Region and by combining the Anadarko Basin with its Texas and Louisiana areas to form the South Region. Certain prior year amounts and historical descriptions have been reclassified to reflect this reorganization. In previous periods, the Company presented the geographic areas as East, Gulf Coast, West and Canada.

On February 23, 2007, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock distribution. The stock dividend was distributed on March 30, 2007 to stockholders of record on March 16, 2007. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

Subsequent events have been evaluated through February 26, 2010, which is also the date that the financial statements were issued.

Recently Adopted Accounting Pronouncements

In July 2009, the Financial Accounting Standards Board (FASB) issued Accounting Standards Codification (ASC) 105, "Generally Accepted Accounting Principles," establishing the accounting standards codification and the hierarchy of generally accepted accounting principles (GAAP) as the sole source of authoritative non-governmental U.S. GAAP. The Codification was not intended to change U.S. GAAP; however, references to various accounting pronouncements and literature will now differ from what was previously being used in practice. Authoritative literature is now referenced by topic rather than by type of standard. As of July 1, 2009, the FASB no longer issues Statements, Interpretations, Staff Positions or EITF Abstracts. The FASB now communicates new accounting standards by issuing an Accounting Standards Update (ASU). All guidance in the Codification has an equal level of authority. ASC 105 is effective for financial statements that cover interim and annual periods ending after September 15, 2009, and supersedes all accounting standards in U.S. GAAP, aside from those issued by the SEC. There was no impact on the Company's financial position, results of operations or cash flows as a result of the Codification.

In February 2008, the FASB issued an amendment to ASC 820, "Fair Value Measurements and Disclosures," which granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities measured on a nonrecurring basis to comply with ASC 820. Effective January 1, 2009, the Company applied these amendments of ASC 820 discussed above and there was no material impact on the Company's financial statements except for the Company's impairment of oil and natural gas properties. For further information, please refer to Note 2 and Note 11 of the Notes to the Consolidated Financial Statements.

Effective January 1, 2009, the Company adopted amendments that the FASB made to ASC 260, "Earnings Per Share," regarding determining whether instruments granted in share-based payment transactions are participating securities. The adoption of these amendments did not have a material impact on the Company's financial statements. For further information, please refer to Note 12 of the Notes to the Consolidated Financial Statements.

In March 2008, the FASB amended the disclosure requirements prescribed in ASC 815, "Derivatives and Hedging." The Company adopted these amendments as of January 1, 2009. The principal impact was to require the expansion of the Company's disclosure regarding its derivative instruments. For further information, please refer to "Derivative Instruments and Hedging Activity" in Note 11 of the Notes to the Consolidated Financial Statements.

In April 2009, the FASB amended guidance in ASC 820 regarding determining fair value when the volume and level of activity for an asset or liability has significantly decreased and identifying transactions that are not orderly. If an entity determines that either the volume or level of activity for an asset or liability has significantly decreased from normal conditions, or that price quotations or observable inputs are not associated with orderly transactions, increased analysis and management judgment will be required to estimate fair value. The objective in fair value measurement remains unchanged from what is prescribed in ASC 820 and should be reflective of the current exit price. Disclosures in interim and annual periods must include inputs and valuation techniques used to measure fair value, along with any changes in valuation techniques and related inputs during the period. In addition, disclosures for debt and equity securities must be provided on a more disaggregated basis. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on the Company's financial position, results of operations or cash flows.

In April 2009, the FASB amended ASC 825, "Financial Instruments," to require disclosures about fair value of financial instruments for publicly traded companies for both interim and annual periods. Historically, these disclosures were only required annually. The interim disclosures are intended to provide financial statement users with more timely and transparent information about the effects of current market conditions on an entity's financial instruments that are not otherwise reported at fair value. These amendments became effective for interim reporting periods ending after June 15, 2009. Comparative disclosures are only required for periods ending after the initial adoption. There was no material impact on the Company's financial position, results of operations or cash flows as a result of the adoption. For further information, please refer to Note 11 of the Notes to the Consolidated Financial Statements.

In April 2009, the FASB amended the other-than-temporary impairment guidance for debt securities in ASC 320, "Investments—Debt and Equity Securities," to make the guidance more operational and to improve the presentation and disclosure of other-than-temporary impairments on debt and equity securities in the financial statements. There were no amendments made to the recognition and measurement guidance for equity securities, but a new method of recognizing and reporting for debt securities was established. Disclosure requirements for impaired debt and equity securities have been expanded significantly and are now required quarterly, as well as annually. These amendments became effective for interim and annual reporting periods ending after June 15, 2009 and did not have a material impact on the Company's financial position, results of operations or cash flows. Comparative disclosures are only required for periods ending after the initial adoption.

In June 2009, the FASB amended ASC 855, "Subsequent Events," to require entities to disclose the date through which they have evaluated subsequent events and whether the date corresponds with the release of their financial statements. In addition, a new concept of financial statements being "available to be issued" was introduced. These amendments became effective for interim and annual periods ending after June 15, 2009 and did not have an impact on the Company's financial position, results of operations or cash flows.

In August 2009, the FASB issued Accounting Standards Update (ASU) No. 2009-05, "Fair Value Measurement and Disclosures: Measuring Liabilities at Fair Value," which provides clarification on measuring liabilities at fair value when a quoted price in an active market is not available. ASU No. 2009-05 specifies that in cases where a quoted price in an active market is not available, a valuation technique should be applied that uses either the quote of the liability when traded as an asset, the quoted prices for similar liabilities or similar liabilities when traded as assets, or another valuation technique consistent with existing fair value measurement guidance. Valuation methods discussed include using an income approach, such as a present value technique, or a market approach based on the amount at the measurement date that the reporting entity would pay to transfer the identical liability or would receive to enter into the identical liability. Entities are not required to include a separate input or adjustment to other inputs relating to the existence of a restriction that prevents the transfer of the liability. ASU No. 2009-05 is codified in ASC 820-10 and is effective for the first reporting period (including interim periods) beginning after issuance. There was no impact on the Company's financial position, results of operations or cash flows as a result of the adoption of ASU No. 2009-05. For further information, please refer to Note 11 of the Notes to the Consolidated Financial Statements.

In December 2008, the SEC issued Release No. 33-8995, "Modernization of Oil and Gas Reporting," which amends the oil and gas disclosures for oil and gas producers contained in Regulations S-K and S-X, as well as adding a section to Regulation S-K (Subpart 1200) to codify the revised disclosure requirements in Securities Act Industry Guide 2, which has been phased out. Release No. 33-8995 is intended to provide investors with a more meaningful and comprehensive understanding of oil and gas reserves. Energy companies affected by Release No. 33-8995 are required to price proved oil and gas reserves using the unweighted arithmetic average of the price on the first day of each month within the 12-month period prior to the end of the reporting period, unless prices are defined by contractual arrangements, excluding escalations based on future conditions. SEC Release No. 33-8995 is effective beginning January 1, 2010. The adoption of Release No. 33-8995 resulted in a downward revision to the Company's proved reserves. For further information, please refer to the Supplemental Oil and Gas Information following Note 13.

In January 2010, the FASB issued ASU No. 2010-03, "Oil and Gas Reserve Estimation and Disclosures," in order to align the oil and gas reserve estimation and disclosure requirements of "Extractive Activities —Oil and Gas" (Topic 932) with the requirements in the SEC's final rule, "Modernization of the Oil and Gas Reporting Requirements" issued in December 2008. The amendments to Topic 932 are effective for annual reporting periods ending on or after December 31, 2009.

In December 2008, the FASB issued an amendment to ASC 715-20, "Compensation – Retirement Benefits – Defined Benefit Plans – General," which requires enhanced disclosures regarding Company benefit plans. Disclosure regarding plan assets should include discussion about how investment allocation decisions are made, the major categories of plan assets, the inputs and valuation techniques used to measure plan assets and significant concentrations of risk within plan assets. These amendments to ASC 715-20 are effective for fiscal years ending after December 15, 2009, and earlier application is permitted. Prior year periods presented for comparative purposes are not required to comply. These amendments to ASC 715-20 did not have a material impact on the Company's financial position, results of operations or cash flows.

Recently Issued Accounting Pronouncements

In January 2010, the FASB issued ASU No. 2010-06, "Improving Disclosures about Fair Value Measurements," which amends ASC 820-10-50 to require new disclosures concerning (1) transfers into and out of Levels 1 and 2 of the fair value measurement hierarchy, and (2) activity in Level 3 measurements. In addition, ASU No. 2010-06 clarifies certain existing disclosure requirements regarding the level of disaggregation and inputs and valuation techniques. Finally, ASU No. 2010-06 makes conforming amendments to the guidance on employers' disclosures about postretirement benefit plans assets (FASB ASC 715-20-50). ASU No. 2010-06 is effective for interim and annual reporting periods beginning after December 15, 2009; however, the requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). Early adoption is allowed. The Company is currently evaluating the impact ASU No. 2010-06 may have on its financial position, results of operations or cash flows.

Inventories

Inventories are comprised of natural gas in storage, tubular goods and well equipment and pipeline imbalances. All inventory balances are carried at the lower of cost or market. Natural gas in storage is valued at average cost. Tubular goods and well equipment are valued at historical cost.

Natural gas gathering and pipeline operations normally include imbalance arrangements with the pipeline. The volumes of natural gas due to or from the Company under imbalance arrangements are recorded at actual selling or purchase prices, as the case may be, and are adjusted monthly to reflect market changes. The net value of the natural gas imbalance is included in inventory in the Consolidated Balance Sheet.

Properties and Equipment

The Company uses the successful efforts method of accounting for oil and gas producing activities. Under this method, acquisition costs for proved and unproved properties are capitalized when incurred. Exploration costs, including geological and geophysical costs, the costs of carrying and retaining unproved properties and exploratory dry hole drilling costs, are expensed. Development costs, including the costs to drill and equip development wells, and successful exploratory drilling costs to locate proved reserves are capitalized.

Exploratory drilling costs are capitalized when incurred pending the determination of whether a well has found proved reserves. The determination is based on a process which relies on interpretations of available geologic, geophysical, and engineering data. If a well is determined to be successful, the capitalized drilling costs will be reclassified as part of the cost of the well. If a well is determined to be unsuccessful, the capitalized drilling costs will be charged to expense in the period the determination is made. If an exploratory well requires a major capital expenditure before production can begin, the cost of drilling the exploratory well will continue to be carried as an asset pending determination of whether proved reserves have been found only as long as: i) the well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made and ii) drilling of the additional exploratory wells is under way or firmly planned for the near future. If drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well is assumed to be impaired, and its costs are charged to exploration expense. For a discussion of the Company's suspended wells, see Note 2 of the Notes to the Consolidated Financial Statements.

The Company determines if an impairment has occurred through either adverse changes or as a result of a review of all fields. The impairment of unamortized capital costs is measured at a field level and is reduced to fair value if it is determined that the sum of the undiscounted expected future net cash flows is less than the net book value. During 2009, 2008 and 2007, the Company recorded total impairments of $17.6 million, $31.3 million (excluding the impairment of $4.4 million of goodwill) and $4.6 million, respectively.

Development costs of proved oil and gas properties, including estimated dismantlement, restoration and abandonment costs and acquisition costs, are depreciated and depleted on a field basis by the units-of-production method using proved developed and proved reserves, respectively. The costs of unproved oil and gas properties are generally combined and impaired over a period that is based on the average holding period for such properties and the Company's experience of successful drilling. Properties related to gathering and pipeline systems and equipment are depreciated using the straight-line method based on estimated useful lives ranging from 10 to 25 years. Generally pipeline and transmission systems are depreciated over 12 to 25 years, gathering and compression equipment is depreciated over 10 years and storage equipment and facilities are depreciated over 10 to 16 years. Certain other assets are depreciated on a straight-line basis over 3 to 10 years. Buildings are depreciated on a straight-line basis over 25 years.

Costs of retired, sold or abandoned properties that make up a part of an amortization base (partial field) are charged to accumulated depreciation, depletion and amortization if the units-of-production rate is not significantly affected. Accordingly, a gain or loss, if any, is recognized only when a group of proved properties (entire field) that make up the amortization base has been retired, abandoned or sold. See Note 2 of the Notes to the Consolidated Financial Statements for a discussion of the disposition of the Company's Canadian properties in 2009.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The associated asset retirement cost is capitalized as part of the carrying amount of the long-lived asset. Subsequently, the asset retirement cost is allocated to expense using a systematic and rational method over the assets useful life. The majority of the asset retirement obligations recorded by the Company relate to the plugging and abandonment of oil and gas wells. However, liabilities are also recorded for meter stations, pipelines, processing plants and compressors. At December 31, 2009, there were no assets legally restricted for purposes of settling asset retirement obligations.

Additional retirement obligations increase the liability associated with new oil and gas wells and other facilities as these obligations are incurred. Accretion expense for the years ended December 31, 2009, 2008 and 2007 was $1.3 million, $1.2 million and $1.1 million, respectively, and was included within Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Operations.

Revenue Recognition and Gas Imbalances

The Company applies the sales method of accounting for natural gas revenue. Under this method, revenues are recognized based on the actual volume of natural gas sold to purchasers. Natural gas production operations may include joint owners who take more or less than the production volumes entitled to them on certain properties. Production volume is monitored to minimize these natural gas imbalances. A natural gas imbalance liability is recorded at the actual price realized upon the gas sale in accounts payable in the Consolidated Balance Sheet if the Company's excess takes of natural gas exceed its estimated remaining proved developed reserves for these properties. See Note 3 of the Notes to the Consolidated Financial Statements for the Company's wellhead gas imbalances.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company determines to be uncollectible based on the specific identification basis. The allowance for doubtful accounts, which is netted against the accounts receivable line on the Consolidated Balance Sheet, was $3.6 million and $3.5 million at December 31, 2009 and 2008, respectively.

Natural Gas Measurement

The Company records estimated amounts for natural gas revenues and natural gas purchase costs based on volumetric calculations under its natural gas sales and purchase contracts. Variances or imbalances resulting from such calculations are inherent in natural gas sales, production, operation, measurement, and administration. Management does not believe that differences between actual and estimated natural gas revenues or purchase costs attributable to the unresolved variances or imbalances are material.

Brokered Natural Gas Margin

The revenues and expenses related to brokering natural gas are reported gross as part of Operating Revenues and Operating Expenses. The Company realizes brokered margin as a result of buying and selling natural gas in back-to-back transactions with separate counterparties. The Company realized $8.3 million, $13.8 million and $11.4 million of brokered natural gas margin in 2009, 2008 and 2007, respectively.

Income Taxes

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred tax assets and liabilities are recorded for the estimated future tax consequences attributable to the differences between the financial carrying amounts of existing assets and liabilities and their respective tax basis. Deferred tax assets and liabilities are measured using the tax rate in effect for the year in which those temporary differences are expected to turn around. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company is required to make judgments, including estimating reserves for potential adverse outcomes regarding tax positions that the Company has taken. The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return. The effective tax rate and the tax basis of assets and liabilities reflect management's estimates of the ultimate outcome of various tax uncertainties. For further information, please refer to Note 6.

Accounts Payable

This account may include credit balances from outstanding checks in zero balance cash accounts. These credit balances are referred to as book overdrafts, as a component of Accounts Payable on the Balance Sheet. There were no credit balances from outstanding checks in zero balance cash accounts included in accounts payable at December 31, 2009 and 2008 as sufficient cash was available for offset.

Risk Management Activities

From time to time, the Company enters into derivative contracts, such as natural gas and crude oil price swaps or zero-cost price collars, as a hedging strategy to manage commodity price risk associated with its production or other contractual commitments. All hedge transactions are subject to the Company's risk management policy which does not permit speculative trading activities. Gains or losses on these hedging activities are generally recognized over the period that its production or other underlying commitment is hedged as an offset to the specific hedged item. Cash flows related to any recognized gains or losses associated with these hedges are reported as cash flows from operations. If a hedge is terminated prior to expected maturity, gains or losses are deferred and included in income in the same period that the underlying production or other contractual commitment is delivered. Unrealized gains or losses associated with any derivative contract not considered a hedge are recognized currently in the results of operations.

When the designated item associated with a derivative instrument matures or is sold, extinguished or terminated, derivative gains or losses are recognized as part of the gain or loss on the sale or settlement of the underlying item. For example, in the case of natural gas price hedges, the gain or loss is reflected in natural gas revenue. When a derivative instrument is associated with an anticipated transaction that is no longer expected to occur or if the hedge is no longer effective, the gain or loss on the derivative is recognized currently in the results of operations to the extent the market value changes in the derivative have not been offset by the effects of the price changes on the hedged item since the inception of the hedge. See Note 11 of the Notes to the Consolidated Financial Statements for further discussion.

Stock-Based Compensation

The Company follows the provisions of ASC 718, "Compensation – Stock Compensation." The tax benefit for stock-based compensation is included as both a cash inflow from financing activities and a cash outflow from operating activities in the Consolidated Statement of Cash Flows. In accordance with ASC 718, the Company recognizes a tax benefit only to the extent it reduces the Company's income taxes payable. For the years ended December 31, 2009 and 2008, the Company realized tax benefits of $13.8 million and $10.7 million, respectively. For the year ended December 31, 2007, the Company did not recognize a tax benefit for stock-based compensation as a result of the tax net operating loss position for the year. See Note 10 of the Notes to the Consolidated Financial Statements for additional details.

Cash and Cash Equivalents

The Company considers all highly liquid short-term investments with original maturities of three months or less to be cash equivalents. Cash and cash equivalents were primarily concentrated in two financial institutions at December 31, 2009 and 2008. The Company periodically assesses the financial condition of these institutions and considers any possible credit risk to be minimal.

Environmental Matters

Environmental expenditures are expensed or capitalized, as appropriate, depending on their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit are expensed. Liabilities related to future costs are recorded on an undiscounted basis when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. Any insurance recoveries are recorded as assets when received.

Use of Estimates

In preparing financial statements, the Company follows generally accepted accounting principles. These principles require management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. The most significant estimates pertain to proved natural gas, natural gas liquids and crude oil reserves and related cash flow estimates used in impairment tests of oil and gas properties, natural gas, natural gas liquids and crude oil revenues and expenses, current values of derivative instruments, as well as estimates of expenses related to legal, environmental and other contingencies, depreciation, depletion and amortization, pension and postretirement obligations, stock-based compensation and deferred income taxes. Actual results could differ from those estimates.

2. Properties and Equipment, Net

Properties and equipment, net are comprised of the following:

(In thousands)	December 31, **2009**	December 31, 2008
Unproved Oil and Gas Properties	**$ 423,373**	$ 315,782
Proved Oil and Gas Properties	**4,118,005**	3,813,014
Gathering and Pipeline Systems	**294,755**	274,192
Land, Building and Other Equipment	**77,474**	68,606
	4,913,607	4,471,594
Accumulated Depreciation, Depletion and Amortization	**(1,555,408)**	(1,335,766)
	$ 3,358,199	$ 3,135,828

The provisions of ASC 932-235-50-1B, "Continued Capitalization of Exploratory Well Costs," require that, in order for costs to be capitalized, a sufficient quantity of reserves must be discovered in the well to justify its completion as a producing well and that sufficient progress must be made in assessing the well's economic and operating feasibility. If both of these requirements are not met, the costs should be expensed. The following table reflects the net changes in capitalized exploratory well costs during 2009, 2008 and 2007.

(In thousands)	December 31, **2009**	2008	2007
Beginning balance at January 1	**$ 5,990**	$ 2,161	$ 8,428
Additions to capitalized exploratory well costs pending the determination of proved reserves	**4,179**	5,990	2,161
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(762)**	(1,259)	(8,011)
Capitalized exploratory well costs charged to expense	**(5,228)**	(902)	(417)
Ending balance at December 31	**$ 4,179**	$ 5,990	$ 2,161

At December 31, 2009, 2008 and 2007, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year after drilling.

The following table provides an aging of capitalized exploratory well costs based on the date the drilling was completed and the number of wells for which exploratory well costs have been capitalized for a period greater than one year since the completion of drilling:

(In thousands)	2009	2008	2007
	December 31,		
Capitalized exploratory well costs that have been capitalized for a period of one year or less	**$ 4,179**	$ 5,990	$ 2,161
Capitalized exploratory well costs that have been capitalized for a period greater than one year	**-**	-	-
Balance at December 31	**$ 4,179**	$ 5,990	$ 2,161
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**-**	-	-

During 2009, the Company recorded $17.6 million of impairments of oil and gas properties. The Company recorded an impairment of $12.0 million in the Fossil Federal field in San Miguel County, Colorado in the North region resulting from lower well performance and $5.6 million in the Beaurline field in Hidalgo County, Texas in the South region resulting from lower well performance. These fields were reduced to fair value of approximately $8.9 million using discounted future cash flows. The fair value of these fields was based on significant inputs that were not observable in the market and are considered to be level 3 inputs as defined in ASC 820. Refer to Note 11 for more information and a description of the fair value hierarchy. Key assumptions include (1) oil and natural gas prices (adjusted for quality and basis differentials), (2) projections of estimated quantities of oil and natural gas reserves and production, (3) estimates of future development and production costs and (4) risk adjusted discount rates (16% at December 31, 2009).

During 2008, the Company recorded an impairment of approximately $3.0 million in the Corral Creek field in Washakie County, Wyoming in the North region resulting from lower than expected performance from the two well field and $28.3 million in the Trawick field in Rusk County, Texas in the South region resulting from a decline in natural gas prices and higher well costs. During 2007, the Company recorded an impairment of approximately $4.6 million in the Castor field in Bienville Parish, Louisiana in the South region resulting from two non-commercial development completions. These impairment charges were reflected in the operating results of the Company for each respective period.

During 2009, 2008 and 2007, the Company recorded impairments of unproved properties of $30.0 million, $41.5 million and $19.0 million, respectively. Included in 2008 impairments were $17.0 million related to the impairment of three exploratory oil and gas prospects located in Mississippi, Montana and North Dakota. These prospects were impaired as a result of the significant decline in commodity prices in the fourth quarter of 2008 and abandonment of the Company's exploration plans.

In April 2008, the Company acquired a small oilfield services business for total consideration of $21.6 million, comprised of the conversion of a $15.6 million note receivable, the issuance of 70,168 shares of Company common stock, and the payment of $2.5 million in cash. The transaction was accounted for as a business combination, and the Company recorded approximately $4.4 million of goodwill. In December 2008, the Company fully impaired the goodwill due to the impact of the broad economic downturn and the related reductions in future drilling programs.

East Texas Property Acquisition

On August 15, 2008, the Company completed the acquisition of certain producing oil and gas properties located in Panola and Rusk counties, Texas in order to expand its position in the Minden field. Total net cash consideration paid by the Company in the transaction was approximately $604.0 million, which reflects the total gross purchase price of $604.4 million adjusted by $0.4 million comprised of a $1.8 million decrease for the impact of purchase price adjustments, including adjustments based on each party's share of production proceeds received, expenses paid and capital costs incurred for periods before and after the effective date of the acquisition of May 1, 2008, and a $1.4 million increase for the impact of transaction costs, which were primarily legal and accounting costs.

The $604.0 million purchase price was allocated to Properties and Equipment and Other Liabilities (for the asset retirement obligation) as follows:

(In thousands)	
Proved Oil and Gas Properties [1]	$ 528,813
Unproved Oil and Gas Properties	52,897
Gathering and Pipeline Systems	22,814
Total Assets Acquired	**604,524**
Less:	
Asset Retirement Obligations	(488)
	$ 604,036

[1] Proved oil and gas properties were determined based on estimated reserves.

The acquired properties were comprised of approximately 25,000 gross leasehold acres with a 97% average working interest near the Company's existing Minden field. Most of the producing properties were operated by the sellers. In addition, the acquisition included a natural gas gathering infrastructure of 31 miles of pipeline, 5,400 horsepower of compression and four water disposal wells. The Company estimated that proved reserves included in the acquisition were approximately 182 Bcfe as of August 1, 2008 (allocated mainly to the Cotton Valley formation).

The east Texas acquisition was recorded using the purchase method of accounting. Financial results for the period from the closing date on August 15, 2008 to December 31, 2009 are included within the Company's 2009 Consolidated Statements of Operations. The following table presents the unaudited pro forma results of operations for the years ended December 31, 2008 and 2007, as if the acquisition was made at the beginning of each period. These pro forma results are not necessarily indicative of future results, nor do they purport to represent the actual financial results that would have occurred had the acquisition been in effect for the periods presented.

	Year Ended December 31,	
(In thousands, except per share amounts)	2008	2007
	(Unaudited)	(Unaudited)
Revenues	**$** 1,009,412	$ 746,089
Net Income..	**$** 218,290	$ 135,992
Earnings Per Share:		
Basic..	**$** 2.12	$ 1.33
Diluted..	**$** 2.10	$ 1.32
Weighted-Average Common Shares Outstanding:		
Basic..	103,142	101,981
Diluted...	104,131	103,133

The Company funded the acquisition with a combination of the net proceeds from its June 2008 sale of approximately five million shares of common stock (see Note 9 of the Notes to the Consolidated Financial Statements) and the net proceeds from its July 2008 private placement of senior unsecured fixed rate notes (see Note 4 of the Notes to the Consolidated Financial Statements). Additionally, in order to mitigate the exposure to price fluctuations of natural gas and crude oil, the Company entered into 12 contracts for natural gas price swaps and three contracts for crude oil swaps in the second quarter of 2008 covering production associated with the acquired properties for the second half of 2008 through 2010.

Disposition of Assets

In April 2009, the Company sold substantially all of its Canadian properties to a private Canadian company. Total consideration received from the sale was $84.4 million, consisting of $64.3 million in cash and $20.1 million in common stock of the Canadian company (included on the Consolidated Balance Sheet as Investment in Equity Securities at December 31, 2009). The common stock investment is being accounted for using the cost method (see Note 11 for the fair value of the common stock at December 31, 2009). The total net book value of the Canadian properties sold was $95.0 million. At December 31, 2008, the Company recorded 40.4 Bcfe of proved reserves (two percent of total proved reserves) related to these properties.

The Company recognized a $3.3 million aggregate loss on sale of assets for the year ended December 31, 2009. This loss included a loss of approximately $16.0 million ($10.1 million, net of taxes) primarily related to the sale of the Canadian properties described above and a gain of $12.7 million primarily related to the sale of Thornwood properties in the North region. Cash proceeds of $11.4 million were received from the sale of the Thornwood properties.

On September 29, 2006, the Company substantially completed the 2006 south Louisiana and offshore properties sale to Phoenix Exploration Company LP for a gross sales price of $340.0 million. The Company received approximately $333.3 million in net proceeds from the sale. In addition to the net gain of $231.2 million ($144.5 million, net of tax) recorded for the year ended December 31, 2006, the Company recorded a net gain of $12.3 million ($7.7 million, net of tax) in the Consolidated Statement of Operations for the year ended December 31, 2007, which included cash proceeds of $5.8 million, $2.1 million in purchase price adjustments and $4.4 million that had been deferred until legal title to certain properties could be assigned.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

(In thousands)	December 31, 2009		December 31, 2008	
ACCOUNTS RECEIVABLE, NET				
Trade Accounts	**$**	**78,656**	$	94,164
Joint Interest Accounts		**3,564**		16,454
Other Accounts		**1,756**		1,987
		83,976		112,605
Allowance for Doubtful Accounts		**(3,614)**		(3,518)
	$	**80,362**	$	109,087
INVENTORIES				
Natural Gas in Storage	**$**	**14,434**	$	27,478
Tubular Goods and Well Equipment		**14,420**		16,439
Pipeline Imbalances		**(864)**		1,760
	$	**27,990**	$	45,677
OTHER CURRENT ASSETS				
Drilling Advances	**$**	**3,417**	$	4,869
Prepaid Balances		**5,980**		7,631
	$	**9,397**	$	12,500
OTHER ASSETS				
Rabbi Trust Deferred Compensation Plan	**$**	**10,031**	$	8,651
Deferred Charges for Credit Agreements		**11,621**		4,847
Other Accounts		**1,412**		1,245
	$	**23,064**	$	14,743
ACCOUNTS PAYABLE				
Trade Accounts	**$**	**17,434**	$	44,088
Natural Gas Purchases		**3,558**		5,346
Royalty and Other Owners		**40,080**		42,349
Capital Costs		**141,122**		117,029
Taxes Other Than Income		**4,267**		5,617
Drilling Advances		**864**		1,289
Wellhead Gas Imbalances		**4,140**		3,354
Other Accounts		**4,123**		3,913
	$	**215,588**	$	222,985
ACCRUED LIABILITIES				
Employee Benefits	**$**	**11,222**	$	10,807
Current Liability for Pension Benefits		**488**		245
Current Liability for Postretirement Benefits		**981**		642
Taxes Other Than Income		**22,780**		16,582
Interest Payable		**20,205**		20,684
Derivative Contracts		**425**		-
Other Accounts		**1,948**		1,591
	$	**58,049**	$	50,551
OTHER LIABILITIES				
Rabbi Trust Deferred Compensation Plan	**$**	**19,087**	$	14,531
Accrued Plugging and Abandonment Liability		**29,676**		27,978
Derivative Contracts		**1,954**		-
Other Accounts		**6,793**		4,717
	$	**57,510**	$	47,226

4. Debt and Credit Agreements

The Company's debt consisted of the following as of:

(In thousands)	**December 31, 2009**	December 31, 2008
Long-Term Debt		
7.19% Notes	**$ -**	$ 20,000
7.33% Weighted-Average Fixed Rate Notes	**170,000**	170,000
6.51% Weighted-Average Fixed Rate Notes	**425,000**	425,000
9.78% Notes	**67,000**	67,000
Credit Facility	**143,000**	185,000
Current Maturities		
7.19% Notes	**-**	(20,000)
Credit Facility	**-**	(15,857)
Total Current Maturities	**-**	(35,857)
Long-Term Debt, excluding Current Maturities	**$ 805,000**	$ 831,143

7.19% Notes

In November 1997, the Company issued an aggregate principal amount of $100 million of its 12-year 7.19% Notes (7.19% Notes) to a group of six institutional investors in a private placement. The 7.19% Notes required five annual $20 million principal payments beginning in November 2005. In November 2009, the final installment of the 7.19% Notes was repaid in full.

7.33% Weighted-Average Fixed Rate Notes

In July 2001, the Company issued $170 million of Notes to a group of seven institutional investors in a private placement. Prior to the determination of the Notes' interest rates, the Company entered into a treasury lock in order to reduce the risk of rising interest rates. Interest rates rose during the pricing period, resulting in a $0.7 million gain that is being amortized over the life of the Notes, and thereby reducing the effective interest rate by 5.5 basis points. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$75,000,000	10-year	July 2011	7.26%
Tranche 2	$75,000,000	12-year	July 2013	7.36%
Tranche 3	$20,000,000	15-year	July 2016	7.46%

The 7.33% weighted-average fixed rate notes contain restrictions on the merger of the Company or any subsidiary with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. Those covenants include a required asset coverage ratio (present value of proved reserves to debt and other liabilities) of at least 1.5 to 1.0, and a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

6.51% Weighted-Average Fixed Rate Notes

In July 2008, the Company issued $425 million of senior unsecured fixed-rate notes to a group of 41 institutional investors in a private placement. The Notes have bullet maturities and were issued in three separate tranches as follows:

	Principal	Term	Maturity Date	Coupon
Tranche 1	$245,000,000	10-year	July 2018	6.44%
Tranche 2	$100,000,000	12-year	July 2020	6.54%
Tranche 3	$ 80,000,000	15-year	July 2023	6.69%

Interest on each series of the 6.51% weighted-average fixed rate notes is payable semi-annually. The Company may prepay all or any portion of the Notes of each series on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The Notes contain restrictions on the merger of the Company with a third party other than under certain limited conditions. There are also various other restrictive covenants customarily found in such debt instruments. These covenants include a required asset coverage ratio (present value of proved reserves plus adjusted cash (as defined in the note purchase agreement) to debt and other liabilities), of at least 1.5 to 1.0, and a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0. The Notes also are subject to customary events of default. The Company is required to offer to prepay the Notes upon specified change in control events accompanied by a ratings decline below investment grade.

9.78% Notes

In December 2008, the Company issued $67 million aggregate principal amount of its 10-year 9.78% Series G Senior Notes to a group of four institutional investors in a private placement. Interest on the Notes is payable semi-annually. The Company may prepay all or any portion of the Notes on any date at a price equal to the principal amount thereof plus accrued and unpaid interest plus a make-whole premium. The other terms of the Notes are substantially similar to the terms of the 6.51% Weighted-Average Fixed Rate Notes.

Revolving Credit Agreement

In April 2009, the Company entered into a new revolving credit facility and terminated its prior credit facility. The credit facility provides for an available credit line of $500 million and contains an accordion feature allowing the Company to increase the available credit line to $600 million, if any one or more of the existing banks or new banks agree to provide such increased commitment amount. The credit facility also provides for the issuance of letters of credit, which would reduce the Company's borrowing capacity. The term of the facility expires in April 2012.

In conjunction with entering into the new credit facility, the Company incurred $10.4 million of debt issuance costs which were capitalized and will be amortized over the term of the credit facility. Additionally, $1.5 million in unamortized costs associated with the prior credit facility will be amortized over the term of the new credit facility in accordance with ASC 470-50, "Debt Modifications and Extinguishments."

The credit facility is unsecured. The available credit line is subject to adjustment from time to time on the basis of (1) the projected present value (as determined by the banks based on the Company's reserve reports and engineering reports) of estimated future net cash flows from certain proved oil and gas reserves and certain other assets of the Company (the "Borrowing Base") and (2) the outstanding principal balance of the Company's senior notes. Under the credit facility, the Borrowing Base is initially set at $1.35 billion, to be periodically redetermined as described below. While the Company does not expect a reduction in the available credit line, in the event that it is adjusted below the outstanding level of borrowings in connection with scheduled redetermination or due to a termination of hedge positions, the Company has a period of six months to reduce its outstanding debt in equal monthly installments to the adjusted credit line available.

The Borrowing Base is redetermined annually under the terms of the credit facility commencing on April 1, 2010. In addition, either the Company or the banks may request an interim redetermination twice a year in connection with certain acquisitions or sales of oil and gas properties.

Interest rates under the credit facility are based on Euro-Dollars (LIBOR) or Base Rate (Prime) indications, plus a margin. These associated margins increase if the total indebtedness under the credit facility and the Company's senior notes is greater than 25%, greater than 50%, greater than 75% or greater than 90% of the Borrowing Base, as shown below:

	Debt Percentage				
	<25%	*≥25% <50%*	*≥50% <75%*	*≥75% <90%*	*≥90%*
Eurodollar Margin	2.000%	2.250%	2.500%	2.750%	3.000%
Base Rate Margin	1.125%	1.375%	1.625%	1.875%	2.125%

The credit facility provides for a commitment fee on the unused available balance at annual rates of 0.50%.

The credit facility contains various customary restrictions, which include the following (with all calculations based on definitions contained in the agreement):

(a) Maintenance of a minimum annual coverage ratio of operating cash flow to interest expense for the trailing four quarters of 2.8 to 1.0.

(b) Maintenance of an asset coverage ratio of the present value of proved reserves plus working capital to debt of 1.5 to 1.0.

(c) Maintenance of a current ratio of 1.0 to 1.0.

(d) Prohibition on the merger or sale of all or substantially all of the Company's or any subsidiary's assets to a third party, except under certain limited conditions.

In addition, the credit facility includes a customary condition to the Company's borrowings under the facility that there has not occurred a material adverse change with respect to the Company.

At December 31, 2009 and 2008, borrowings outstanding under the Company's credit facilities were $143 million and $185 million, respectively. In addition, the Company had $1.0 million letters of credit outstanding at December 31, 2009.

The Company's weighted-average effective interest rates for the credit facilities during the years ended December 31, 2009, 2008 and 2007 were approximately 4.0%, 4.8% and 7.2%, respectively. As of December 31, 2009 and 2008, the weighted-average interest rate on the Company's credit facility was approximately 3.9% and 3.7%, respectively.

The Company believes it was in compliance with its covenants contained in its various debt agreements at December 31, 2009 and 2008 and during the years then ended.

5. Employee Benefit Plans

Pension Plan

The Company has an underfunded non-contributory, defined benefit pension plan for all full-time employees. Plan benefits are based primarily on years of service and salary level near retirement. Plan assets are mainly equity securities and fixed income investments. The Company complies with the Employee Retirement Income Security Act (ERISA) of 1974 and Internal Revenue Code limitations when funding the plan.

The Company has an unfunded non-qualified equalization plan to ensure payments to certain executive officers of amounts to which they are already entitled under the provisions of the pension plan, but which are subject to limitations imposed by federal tax laws.

Obligations and Funded Status

The funded status represents the difference between the projected benefit obligation of the Company's qualified and non-qualified pension plans and the fair value of the qualified pension plan's assets at December 31.

The change in the combined projected benefit obligation of the Company's qualified and non-qualified pension plans and the change in the Company's qualified plan assets at fair value during the last three years are as follows:

(In thousands)	**2009**	2008	2007
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 63,008**	$ 51,603	$ 45,475
Service Cost	**3,443**	3,313	2,931
Interest Cost	**3,712**	3,272	2,769
Actuarial Loss	**6,262**	5,683	1,314
Benefits Paid	**(1,333)**	(863)	(886)
Benefit Obligation at End of Year	**75,092**	63,008	51,603
Change in Plan Assets			
Fair Value of Plan Assets at Beginning of Year	**34,295**	44,744	38,189
Actual Return on Plan Assets	**10,903**	(13,682)	3,179
Employer Contributions	**10,136**	5,000	5,000
Benefits Paid	**(1,333)**	(863)	(886)
Expenses Paid	**(821)**	(904)	(738)
Fair Value of Plan Assets at End of Year	**53,180**	34,295	44,744
Funded Status at End of Year	**$ (21,912)**	$ (28,713)	$ (6,859)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet at December 31 consist of the following:

(In thousands)	**2009**	2008	2007
Current Liabilities	**$ (488)**	$ (245)	$ (116)
Long-Term Liabilities	**(21,424)**	(28,468)	(6,743)
	$ (21,912)	$ (28,713)	$ (6,859)

Amounts Recognized in Accumulated Other Comprehensive Income

Amounts recognized in accumulated other comprehensive income at December 31 consist of the following:

(In thousands)	**2009**	2008	2007
Prior Service Cost	**$ 92**	$ 143	$ 194
Net Actuarial Loss	**32,061**	36,373	13,744
	$ 32,153	$ 36,516	$ 13,938

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets

(In thousands)	**2009**	2008	2007
Projected Benefit Obligation	**$ 75,092**	$ 63,008	$ 51,603
Accumulated Benefit Obligation	**$ 61,822**	$ 48,050	$ 39,544
Fair Value of Plan Assets	**$ 53,180**	$ 34,295	$ 44,744

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income Combined Qualified and Non-Qualified Pension Plans

(In thousands)	**2009**	2008	2007
Components of Net Periodic Benefit Cost			
Current Year Service Cost	**$ 3,443**	$ 3,313	$ 2,931
Interest Cost	**3,712**	3,272	2,769
Expected Return on Plan Assets	**(2,685)**	(3,535)	(3,015)
Amortization of Prior Service Cost	**51**	51	142
Amortization of Net Loss	**3,177**	1,175	1,089
Net Periodic Pension Cost	**$ 7,698**	$ 4,276	$ 3,916
Other Changes in Qualified Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income			
Net (Gain)/Loss	**$ (1,135)**	$ 23,804	$ 1,887
Amortization of Net Loss	**(3,177)**	(1,175)	(1,089)
Amortization of Prior Service Cost	**(51)**	(51)	(142)
Total Recognized in Other Comprehensive Income	**(4,363)**	22,578	656
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$ 3,335**	$ 26,854	$ 4,572

The estimated prior service cost and net loss for the qualified defined benefit pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are less than $0.1 million and $2.2 million, respectively.

The estimated prior service cost and net loss for the defined benefit non-qualified pension plan that will be amortized from accumulated other comprehensive income into net periodic benefit cost over the next fiscal year are less than $0.1 million and $0.3 million, respectively.

Assumptions

Weighted-average assumptions used to determine projected pension benefit obligations at December 31 were as follows:

	2009	2008	2007
Discount Rate	**5.75%**	5.75%	6.00%
Rate of Compensation Increase	**4.00%**	4.00%	4.00%

Weighted-average assumptions used to determine net periodic pension costs at December 31 are as follows:

	2009	2008	2007
Discount Rate..	**5.75%**	6.00%	5.75%
Expected Long-Term Return on Plan Assets.......	**8.00%**	8.00%	8.00%
Rate of Compensation Increase...........................	**4.00%**	4.00%	4.00%

The long-term expected rate of return on plan assets used in 2009, as shown above, is 8%. The Company establishes the long-term expected rate of return by developing a forward looking long-term expected rate of return assumption for each asset class, taking into account factors such as the expected real return for the specific asset class and inflation. One of the plan objectives is that performance of the equity portion of the pension plan exceed the Standard and Poors' 500 Index over the long-term. The Company also seeks to achieve a minimum five percent annual real rate of return (above the rate of inflation) on the total portfolio over the long-term. In the Company's pension calculations, the Company has used eight percent as the expected long-term return on plan assets for 2009, 2008 and 2007. In order to derive this return, a Monte Carlo simulation was run using 5,000 simulations based upon the Company's actual asset allocation and liability duration, which has been determined to be approximately 15 years. This model uses historical data for the period of 1926-2007 for stocks, bonds and cash to determine the best estimate range of future returns. The median rate of return, or return that the Company expects to achieve over 50% of the time, is approximately 9%. The Company expects to achieve at a minimum approximately 7% annual real rate of return on the total portfolio over the long-term at least 75% of the time. The Company believes that the 8% chosen is a reasonable estimate based on its actual results.

Plan Assets

The Company's pension plan assets were accounted for at fair value and are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Each portfolio uses independent pricing services approved by the Trustee to value the Company's investments. All common/collective trust funds are managed by the Trustee. Refer to Note 11 for more information and a description of the fair value hierarchy.

The Company's investments in equity securities for which market quotations are readily available are valued at the last reported sale price or official closing price as reported by an independent pricing service on the primary market or exchange on which they are traded.

The Company's investment in debt securities are valued based on quotations received from dealers who transact in markets with such securities or by independent pricing services. For corporate bonds, bank notes, floating rate loans, foreign government and government agency obligations, municipal securities, preferred securities, supranational obligations, U.S. government and government agency obligations pricing services generally utilize matrix pricing which considers yield or price of bonds of comparable quality, coupon, maturity and type as well as dealer supplied prices.

At December 31, 2009 and 2008, the non-qualified pension plan did not have plan assets. The fair value of the plan assets of the Company's qualified pension plan at December 31, 2009 and 2008 by asset category are as follows:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Asset Category				
Cash	$ 1,486	$ -	$ -	**$ 1,486**
Equity securities:				
Domestic:				
Large-cap	-	13,070	-	**13,070**
Small-cap	-	2,731	-	**2,731**
Growth	-	4,544	-	**4,544**
International:				
Diversified	-	9,623	-	**9,623**
Small-cap	-	2,140	-	**2,140**
Debt securities	-	19,586	-	**19,586**
	$ 1,486	$ 51,694	$ -	**$ 53,180**

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2008
Asset Category				
Cash	$ 311	$ -	$ -	**$ 311**
Equity securities:				
Domestic:				
Large-cap	-	12,165	-	**12,165**
Small-cap	-	-	-	-
Growth	-	3,991	-	**3,991**
International:				
Diversified	-	4,863	-	**4,863**
Small-cap	-	2,567	-	**2,567**
Debt securities	-	10,398	-	**10,398**
	$ 311	$ 33,984	$ -	**$ 34,295**

The Company's investment strategy for benefit plan assets is to invest in funds to maximize the return over the long-term, subject to an appropriate level of risk. Additionally, the objective is for each class of investments to outperform its representative benchmark over the long-term. The Company generally targets a portfolio of assets utilizing equity securities, debt securities and cash equivalents that are within a range of approximately 50% to 80% for equity securities and approximately 20% to 40% for fixed income securities. Large capitalization equities may make up a maximum of 65% of the portfolio. Small capitalization equities and international equities may make up a maximum of 30% and 15%, respectively, of the portfolio. Fixed income bonds may make up a maximum of 40% of the portfolio. The Company's plan assets will typically be fully invested within these investments of the portfolio; however, as a temporary investment or an asset protection measure, part of the plan assets may be invested in money market investments up to 20%. One percent of the portfolio is invested in short-term funds at the designated bank to meet the cash flow needs of the plan. No prohibited investments, including direct or indirect investments in commodities, commodity futures, derivatives, short sales, real estate investment trusts, letter stock, restricted stock or other private placements, are allowed without prior committee approval.

Cash Flows

Contributions

The funding levels of the pension plans are in compliance with standards set by applicable law or regulation. In 2009, the Company did not have any required minimum funding obligations; however, it chose to fund $10 million into the qualified plan. In 2010, the Company does not have any required minimum funding obligations for the qualified pension plan. The Company will contribute an estimated $0.5 million, as shown below, for the non-qualified pension plan. Currently, management has not determined if any additional discretionary funding will be made in 2010.

Estimated Future Benefit Payments

The following estimated benefit payments under the Company's qualified and non-qualified pension plans, which reflect expected future service, as appropriate, are expected to be paid as follows:

(In thousands)	**Qualified**	**Non-Qualified**	**Total**
2010	$ 1,431	$ 501	$ 1,932
2011	1,737	406	2,143
2012	2,236	1,097	3,333
2013	2,699	1,721	4,420
2014	3,051	259	3,310
Years 2015 - 2019	23,548	4,706	28,254

Postretirement Benefits Other than Pensions

In addition to providing pension benefits, the Company provides certain health care benefits for retired employees, including their spouses, eligible dependents and surviving spouses (retirees). These benefits are commonly called postretirement benefits. The health care plans are contributory, with participants' contributions adjusted annually. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 251 retirees and their dependents at the end of 2009 and 234 retirees and their dependents at the end of 2008.

When the Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pension," (now codified in ASC 715-60, "Compensation – Retirement Benefits – Defined Benefit Plans – Other Postretirement") in 1992, it began amortizing the $16.9 million accumulated postretirement benefit, known as the transition obligation, over a period of 20 years, or $0.8 million per year which is included in the annual expense of the plan. Included in the transition obligation are the effects of plan amendments during 1996, 2000 and 2004. As a result of subsequent updates to the requirements for accounting for Defined Benefit Plans codified in ASC 715-20, "Compensation – Retirement Benefits – Defined Benefit Plans – General," the remaining unamortized balance at December 31, 2006 of $3.2 million is now recognized in accumulated other comprehensive income. Additionally, a portion of this amount will be amortized and reclassified from the balance sheet to the income statement as expense each year.

Obligations and Funded Status

The funded status represents the difference between the accumulated benefit obligation of the Company's postretirement plan and the fair value of plan assets at December 31. The postretirement plan does not have any plan assets; therefore, the funded status is equal to the amount of the December 31 accumulated benefit obligation.

The change in the Company's postretirement benefit obligation during the last three years, as well as the funded status at the end of the last three years is as follows:

(In thousands)	**2009**	2008	2007
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 26,888**	$ 20,846	$ 18,781
Service Cost	**1,279**	1,083	871
Interest Cost	**1,594**	1,380	1,076
Actuarial Loss	**5,917**	4,270	880
Benefits Paid	**(1,286)**	(691)	(762)
Benefit Obligation at End of Year	**34,392**	26,888	20,846
Change in Plan Assets			
Fair Value of Plan Assets at End of Year	**N/A**	N/A	N/A
Funded Status at End of Year	**$ (34,392)**	$ (26,888)	$ (20,846)

Amounts Recognized in the Balance Sheet

Amounts recognized in the balance sheet at December 31 consist of the following:

(In thousands)	**2009**	2008	2007
Current Liabilities	**$ (981)**	$ (642)	$ (642)
Long-Term Liabilities	**(33,411)**	(26,246)	(20,204)
	$ (34,392)	$ (26,888)	$ (20,846)

Amounts Recognized in Accumulated Other Comprehensive Income

Amounts recognized in accumulated other comprehensive income at December 31 consist of the following:

(In thousands)	**2009**	2008	2007
Transition Obligation	**$ 1,263**	$ 1,895	$ 2,527
Prior Service Cost	**-**	666	1,618
Net Actuarial Loss	**13,455**	8,214	4,392
	$ 14,718	$ 10,775	$ 8,537

The estimated net obligation at transition and net loss for the defined benefit postretirement plan that will be amortized from accumulated other comprehensive income into net periodic postretirement cost over the next fiscal year are $0.6 million and $1.0 million, respectively.

Components of Net Periodic Benefit Cost

(In thousands)	**2009**	2008	2007
Components of Net Periodic Postretirement Benefit Cost			
Current Year Service Cost	**$ 1,279**	$ 1,083	$ 871
Interest Cost	**1,594**	1,380	1,076
Amortization of Prior Service Cost	**666**	952	952
Amortization of Net Obligation at Transition	**632**	632	632
Amortization of Net Loss	**676**	448	193
Net Periodic Postretirement Cost	**4,847**	4,495	3,724
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income			
Net Loss	**$ 5,917**	$ 4,270	$ 880
Amortization of Prior Service Cost	**(666)**	(952)	(952)
Amortization of Net Obligation at Transition	**(632)**	(632)	(632)
Amortization of Net Loss	**(676)**	(448)	(193)
Total Recognized in Other Comprehensive Income	**3,943**	2,238	(897)
Total Recognized in Qualified Net Periodic Benefit Cost and Other Comprehensive Income	**$ 8,790**	$ 6,733	$ 2,827

Assumptions

Assumptions used to determine projected postretirement benefit obligations and postretirement costs are as follows:

	2009	2008	2007
Discount Rate [(1)]	**5.75%**	5.75%	6.00%
Health Care Cost Trend Rate for Medical Benefits Assumed for Next Year	**10.00%**	9.00%	9.00%
Rate to which the cost trend rate is assumed to decline (the Ultimate Trend Rate)	**5.00%**	5.00%	5.00%
Year that the rate reaches the Ultimate Trend Rate	**2015**	2013	2012

(1) *Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2009, 2008 and 2007, respectively, the beginning of year discount rates of 5.75%, 6.0% and 5.75% were used.*

Coverage provided to participants age 65 and older is under a fully-insured arrangement. The Company subsidy is limited to 60% of the expected annual fully-insured premium for participants age 65 and older. For all participants under age 65, the Company subsidy for all retiree medical and prescription drug benefits, beginning January 1, 2006, was limited to an aggregate annual amount not to exceed $648,000. This limit increases by 3.5% annually thereafter. The Company prepaid the life insurance premiums for all retirees retiring before January 1, 2006 eliminating all future premiums for retiree life insurance. A life insurance product is offered to employees allowing employees to continue coverage into retirement by paying the premiums directly to the life insurance provider.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effects:

(In thousands)	**1-Percentage-Point Increase**	**1-Percentage-Point Decrease**
Effect on total of service and interest cost	$ 603	$ (487)
Effect on postretirement benefit obligation	5,349	(4,385)

Cash Flows

Contributions

The Company expects to contribute approximately $1.0 million to the postretirement benefit plan in 2010.

Estimated Future Benefit Payments

The following estimated benefit payments under the Company's postretirement plans, which reflect expected future service, as appropriate, are expected to be paid as follows:

(In thousands)		
2010	$	1,009
2011		1,134
2012		1,277
2013		1,482
2014		1,702
Years 2015 - 2019		11,572

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) introduced a prescription drug benefit under Medicare as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to certain Medicare benefits. In accordance with accounting and disclosure requirements related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 codified in ASC 715-60, any measures of the accumulated plan benefit obligation or net periodic postretirement benefit cost in the financial statements or accompanying notes do not reflect the effects of the Act on the Company's plan. As amended by the Company on January 1, 2006, the postretirement benefit plan excludes prescription drug benefits to participants age 65 and older. Due to this amendment, there was no impact on operating results, financial position or cash flows of the Company.

Savings Investment Plan

The Company has a Savings Investment Plan (SIP), which is a defined contribution plan. The Company matches a portion of employees' contributions in cash. Participation in the SIP is voluntary, and all regular employees of the Company are eligible to participate. The Company charged to expense plan contributions of $2.2 million, $2.2 million and $2.0 million in 2009, 2008 and 2007, respectively. The Company matches employee contributions dollar-for-dollar on the first six percent of an employee's pretax earnings. The Company's common stock is an investment option within the SIP.

Deferred Compensation Plan

In 1998, the Company established a Deferred Compensation Plan. This plan is available to officers of the Company and acts as a supplement to the Savings Investment Plan. If the participant's base salary and bonus deferrals cause the participant to not receive the full six percent company match to the Savings Investment Plan, the Company will make a contribution annually into the Deferred Compensation Plan to ensure that the participant receives a full matching contribution from the Company. Unlike the SIP, the Deferred Compensation Plan does not have dollar limits on tax deferred contributions. However, the assets of this plan are held in a rabbi trust and are subject to additional risk of loss in the event of bankruptcy or insolvency of the Company.

The officer participants guide the diversification of trust assets. The trust assets are invested in either mutual funds that cover the investment spectrum from equity to money market, or may include holdings of the Company's common stock, which is funded by the issuance of shares to the trust. The mutual funds are publicly traded, have market prices that are readily available and are reported at market value. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets, excluding the Company's common stock, was $10.0 million and $8.7 million at December 31, 2009 and 2008, respectively, and is included within Other Assets in the Consolidated Balance Sheet. Related liabilities, including the Company's common stock, totaled $19.1 million and $14.5 million at December 31, 2009 and 2008, respectively, and are included within Other Liabilities in the Consolidated Balance Sheet. With the exception of the Company's common stock, there is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets because the changes in market value of the trust assets are offset completely by changes in the value of the liability, which represents trust assets belonging to plan participants.

The Company's common stock held in the rabbi trust is recorded at the market value on the date of deferral, which totaled $8.2 million and $9.5 million at December 31, 2009 and 2008, respectively and is included within Additional Paid-in Capital in Stockholders' Equity in the Consolidated Balance Sheet. As of December 31 2009, 225,800 shares of the Company's stock representing vested performance share awards were deferred into the rabbi trust. During 2009, an increase to the rabbi trust deferred compensation liability of $4.6 million was recognized, representing the increase in the closing price of all shares from December 31, 2008 to December 31, 2009 in addition to a reduction in the liability due to shares that were sold out of the rabbi trust. This increase in stock-based compensation expense was included in General and Administrative expense in the Consolidated Statement of Operations. The Company's common stock issued to the trust is not considered outstanding for purposes of calculating basic earnings per share, but is considered a common stock equivalent in the calculation of diluted earnings per share.

The Company did not make any plan contributions in 2009. The Company charged to expense plan contributions of less than $20,000 in each of 2008 and 2007.

6. Income Taxes

Income tax expense / (benefit) is summarized as follows:

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Current			
Federal	**$ (26,323)**	$ 2,631	$ (1,424)
State	**(545)**	30	(3,619)
Total	**(26,868)**	2,661	(5,043)
Deferred			
Federal	**100,896**	116,127	91,257
State	**919**	5,545	3,895
Total	**101,815**	121,672	95,152
Total Income Tax Expense	**$ 74,947**	$ 124,333	$ 90,109

Total income taxes were different than the amounts computed by applying the statutory federal income tax rate as follows:

(Dollars in thousands)	Year Ended December 31, 2009	2008	2007
Statutory Federal Income Tax Rate	**35%**	35%	35%
Computed "Expected" Federal Income Tax	**$ 78,153**	$ 117,468	$ 90,137
State Income Tax, Net of Federal Income Tax Benefit	**4,476**	6,581	5,452
Sale of Foreign Assets	**(1,656)**	-	-
Benefit Related to Favorable State Tax Determination [1]	**-**	-	(2,831)
Deferred Tax Benefit Related to Reduction in Overall State Tax Rate	**(3,925)**	(1,453)	(1,378)
Other, Net	**(2,101)**	1,737	(1,271)
Total Income Tax Expense	**$ 74,947**	$ 124,333	$ 90,109

[1] *In November 2007, the Company received a favorable ruling letter related to the computation of income taxes for 2006.*

The tax effects of temporary differences that resulted in significant portions of the deferred tax liabilities and deferred tax assets as of December 31 were as follows:

(In thousands)	Year Ended December 31, 2009	2008
Deferred Tax Liabilities		
Property, Plant and Equipment	**$ 765,811**	$ 644,347
Hedging Liabilities / Receivables	**42,243**	132,474
Prepaid Expenses and Other	**1,635**	6,540
Total	**809,689**	783,361
Deferred Tax Assets		
Alternative Minimum Tax Credit	**38,835**	17,764
Net Operating Loss	**31,719**	40,339
Pension and Other Post-Retirement Benefits	**20,914**	22,347
Items Accrued for Financial Reporting Purposes and Other	**38,316**	39,820
Total	**129,784**	120,270
Net Deferred Tax Liabilities	**$ 679,905**	$ 663,091

As of December 31, 2009, the Company had alternative minimum tax credit carryforwards of $38.8 million that do not expire and can be used to offset regular income taxes in future years to the extent that regular income taxes exceed the alternative minimum tax in any such year. The Company also had net operating loss carryforwards of $62.5 million for federal reporting purposes and $188.2 million for state reporting purposes. The majority of the state net operating loss carryforwards will expire between 2016 and 2029. It is expected that these deferred tax benefits will be utilized prior to their expiration.

Uncertain Tax Positions

ASC 740, "Income Taxes," prescribes a two-step process for accounting for income tax uncertainties. First, a threshold condition of "more likely than not" should be met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. Under ASC 740, the Company may recognize the tax benefit from an uncertain tax position only if it is more likely than not that the tax position will be sustained on examination by the taxing authorities, based on the technical merits of the position. If the recognition threshold is met, ASC 740 provides additional guidance on measuring the amount of the uncertain tax position. The tax benefits recognized in the financial statements from such a position should be measured based on the largest benefit that has a greater than fifty percent likelihood of being realized upon ultimate settlement. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and increased disclosure of these uncertain tax positions.

The Company adopted the uncertain tax positions provisions of ASC 740 on January 1, 2007, and did not recognize any change to the liability for unrecognized tax benefits.

The Company recognizes accrued interest related to uncertain tax positions in Interest Expense and Other and accrued penalties related to such positions in General and Administrative expense in the Consolidated Statement of Operations, which is consistent with the recognition of these items in prior reporting periods. As of December 31, 2009, the Company determined that no accrual for penalties was required.

As of December 31, 2009, 2008 and 2007, the Company's unrecognized tax benefits were $0.5 million, $0.5 million and $2.4 million, respectively. These amounts, if recognized, would not have a significant impact on the effective tax rate.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Unrecognized tax benefit balance at beginning of year	**$ 500**	$ 2,425	$ 1,029
Additions based on tax positions related to the current year	**-**	-	-
Additions for tax positions of prior years	**-**	-	1,415
Reductions for tax positions of prior years	**-**	(1,925)	(19)
Settlements	**-**	-	-
Unrecognized tax benefit balance at end of year	**$ 500**	$ 500	$ 2,425

During 2008, the Company executed a final settlement agreement with the Internal Revenue Service that reduced unrecognized tax benefits by $1.9 million. This reduction did not affect the effective tax rate. The amount of remaining unrecognized tax benefits as of December 31, 2009, if recognized, would not have a significant impact on the effective tax rate. It is possible that the amount of unrecognized tax benefits will change in the next twelve months. The Company does not expect that a change would have a significant impact on its results of operations, financial position or cash flows.

The Company files income tax returns in the U.S. federal jurisdiction, various states and Canada. The Company is no longer subject to examinations by state authorities before 2001. The Company is currently under examination by the Internal Revenue Service for 2006 through 2008.

7. Commitments and Contingencies

Firm Gas Transportation Agreements

The Company has incurred, and will incur over the next several years, demand charges on firm gas transportation agreements. These agreements provide firm transportation capacity rights on pipeline systems in the North region. The remaining terms on these agreements range from less than one year to approximately 20 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company. If the Company does not utilize the capacity, it can release it to others, thus reducing its potential liability. The agreements that the Company previously had in place on pipeline systems in Canada were transferred in April 2009 to the buyer in connection with the sale of its Canadian properties (discussed in Note 2).

Future obligations under firm gas transportation agreements in effect at December 31, 2009 are as follows:

(In thousands)		
2010	$	10,977
2011		10,961
2012		10,638
2013		3,373
2014		3,373
Thereafter		41,081
	$	**80,403**

Drilling Rig Commitments

The Company has two drilling rigs in the South region that are under contracts with initial terms of greater than one year. As of December 31, 2009, the Company is obligated under these contracts to pay $6.4 million during 2010.

Lease Commitments

The Company leases certain transportation vehicles, warehouse facilities, office space, and machinery and equipment under cancelable and non-cancelable leases. During 2008, the Company entered into a lease for new office space in Houston. The new lease commenced in August 2009 and will expire approximately six years from commencement. All other operating leases expire within the next five years, and some of these leases may be renewed. Rent expense under such arrangements totaled $17.4 million, $14.6 million and $12.3 million for the years ended December 31, 2009, 2008 and 2007, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2009 are as follows:

(In thousands)		
2010	$	5,845
2011		5,159
2012		4,870
2013		4,502
2014		3,941
Thereafter		2,459
	$	**26,776**

Contingencies

The Company is a defendant in various legal proceedings arising in the normal course of its business. All known liabilities are accrued based on management's best estimate of the potential loss. While the outcome and impact of such legal proceedings on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the Company's consolidated financial position or cash flow. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Commitment and Contingency Reserves

When deemed necessary, the Company establishes reserves for certain legal proceedings. The establishment of a reserve involves an estimation process that includes the advice of legal counsel and subjective judgment of management. While management believes these reserves to be adequate, it is reasonably possible that the Company could incur approximately $0.9 million of additional loss with respect to those matters in which reserves have been established. Future changes in the facts and circumstances could result in the actual liability exceeding the estimated ranges of loss and amounts accrued.

While the outcome and impact on the Company cannot be predicted with certainty, management believes that the resolution of these proceedings through settlement or adverse judgment will not have a material adverse effect on the consolidated financial position or cash flow of the Company. Operating results, however, could be significantly impacted in the reporting periods in which such matters are resolved.

Settlement of Dispute

In December 2008, the Company settled a dispute with a third party resulting in the Company recording a gain of $51.9 million (approximately $32.5 million after-tax). The dispute involved the propriety of possession of the Company's intellectual property by a third party. The settlement was comprised of $20.2 million in cash paid by the third party to the Company and $31.7 million related to the fair value of unproved property rights transferred by the third party to the Company. The fair market value of the unproved property rights was determined based on observable market costs and conditions over a recent time period. Values were pro-rated by property based on the primary term remaining on the properties.

8. Cash Flow Information

Cash paid / (received) for interest and income taxes is as follows:

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Interest........................	**$ 56,301**	$ 23,089	$ 20,257
Income Taxes............	**27,080**	(33,753)	(20,099)

9. Capital Stock

Incentive Plans

Under the Company's 2004 Incentive Plan, incentive and non-statutory stock options, stock appreciation rights (SARs), stock awards, cash awards and performance awards may be granted to key employees, consultants and officers of the Company. Non-employee directors of the Company may be granted discretionary awards under the 2004 Incentive Plan consisting of stock options or stock awards. In the first quarter of 2007, the Board of Directors eliminated the automatic award of an option to purchase 30,000 shares of common stock on the date the non-employee directors first join the Board of Directors. In its place, the Board of Directors considers an annual fixed dollar stock award which is competitive with the Company's peer group. A total of 5,100,000 shares of common stock may be issued under the 2004 Incentive Plan. Under the 2004 Incentive Plan, no more than 1,800,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 3,000,000 shares may be issued pursuant to incentive stock options.

Stock Issuance

On June 20, 2008, the Company entered into an underwriting agreement, pursuant to which the Company sold an aggregate of 5,002,500 shares of common stock at a price to the Company of $62.66 per share. On June 25, 2008, the Company closed the public offering and received $313.5 million in net proceeds, after deducting underwriting discounts and commissions. These net proceeds were used temporarily to reduce outstanding borrowings under the Company's revolving credit facility prior to funding a portion of the purchase price of the Company's east Texas acquisition, which closed in the third quarter of 2008.

Immediately prior to (and in connection with) this issuance, the Company retired 5,002,500 shares of its treasury stock, which had a weighted-average purchase price of $16.46, representing $82.3 million. In accordance with the Company's policy, the excess of cost of the treasury stock over its par value was charged entirely to additional paid-in capital.

Stock Split

On February 23, 2007, the Board of Directors declared a 2-for-1 split of the Company's common stock in the form of a stock distribution. The stock dividend was distributed on March 30, 2007 to stockholders of record on March 16, 2007. All common stock accounts and per share data have been retroactively adjusted to give effect to the 2-for-1 split of the Company's common stock.

Increase in Authorized Shares

In April 2009, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 120 million to 240 million shares.

Treasury Stock

The Board of Directors has authorized a share repurchase program under which the Company may purchase shares of common stock in the open market or in negotiated transactions. The timing and amount of these stock purchases are determined at the discretion of management. The Company may use the repurchased shares to fund stock compensation programs presently in existence, or for other corporate purposes. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase securities of the Company.

During the year ended December 31, 2009, the Company did not repurchase any shares of common stock. Since the authorization date, the Company has repurchased 5,204,700 shares of the 10 million total shares authorized for a total cost of approximately $85.7 million. The repurchased shares were held as treasury stock. No treasury shares have been delivered or sold by the Company subsequent to the repurchase. In connection with the June 2008 common stock issuance, the Company retired 5,002,500 shares of its treasury stock as discussed above under the heading "Stock Issuance." As of December 31, 2009, 202,200 shares were held as treasury stock.

Dividend Restrictions

The Board of Directors of the Company determines the amount of future cash dividends, if any, to be declared and paid on the common stock depending on, among other things, the Company's financial condition, funds from operations, the level of its capital and exploration expenditures, and its future business prospects. None of the note or credit agreements in place have a restricted payment provision or other provision limiting dividends.

Expired Purchase Rights Plan

On January 21, 1991, the Board of Directors adopted the Preferred Stock Purchase Rights Plan and declared a dividend distribution of one right for each outstanding share of common stock. On December 8, 2000, the rights agreement for the plan was amended and restated to extend the term of the plan to 2010 and to make other changes. At December 31, 2009 there were no shares of Junior Preferred Stock issued or outstanding. The rights plan expired on January 21, 2010.

10. Stock-Based Compensation

Compensation expense charged against income for stock-based awards (including the supplemental employee incentive plans discussed below) for the years ended December 31, 2009, 2008 and 2007 was $25.1 million, $34.5 million and $15.3 million, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations.

For the year ended December 31, 2009, the Company realized a $13.8 million tax benefit related primarily to the federal tax deduction in excess of book compensation cost for employee stock-based compensation for 2008 and, to a lesser extent, state tax deductions for 2007. For regular federal income tax purposes, the Company was in a net operating loss position in 2008. As the Company carried back net operating losses concurrent with its 2008 tax return filing, the income tax benefit related to stock-based compensation was recorded in 2009. In accordance with ASC 718, the Company is able to recognize this tax benefit only to the extent it reduces the Company's income taxes payable. For the year ended December 31, 2008, the Company realized a $10.7 million tax benefit related to the 2007 federal tax deduction in excess of book compensation cost related to employee stock-based compensation. Such income tax benefit related to the stock-based compensation was recorded in 2008 as the Company carried back net operating losses concurrent with the 2007 tax return filing. The Company did not recognize a tax benefit related to stock-based compensation in 2007 as a result of the tax net operating loss position for the year. Under ASC 718, the tax benefits resulting from tax deductions in excess of expense are reported as an operating cash outflow and a financing cash inflow. For the years ended December 31, 2009 and 2008, $13.8 million and $10.7 million were reported in these two separate line items in the Consolidated Statement of Cash Flows.

Restricted Stock Awards

Most restricted stock awards vest either at the end of a three year service period, or on a graded-vesting basis of one-third at each anniversary date over a three year service period. Under the graded-vesting approach, the Company recognizes compensation cost over the three year requisite service period for each separately vesting tranche as though the awards are, in substance, multiple awards. For awards that vest at the end of the three year service period, expense is recognized ratably using a straight-line expensing approach over three years. For all restricted stock awards, vesting is dependent upon the employees' continued service with the Company, with the exception of employment termination due to death, disability or retirement.

The fair value of restricted stock grants is based on the average of the high and low stock price on the grant date. The maximum contractual term is four years. In accordance with ASC 718, the Company accelerated the vesting period for retirement-eligible employees for purposes of recognizing compensation expense in accordance with the vesting provisions of the Company's stock-based compensation programs for awards issued after the adoption of ASC 718. The Company used an annual forfeiture rate ranging from 0% to 7.1% based on approximately ten years of the Company's history for this type of award to various employee groups.

The following table is a summary of restricted stock award activity for the year ended December 31, 2009:

Restricted Stock Awards	Shares	Weighted-Average Grant Date Fair Value per share	Weighted-Average Remaining Contractual Term (in years)	Aggregate Intrinsic Value (in thousands) [1]
Non-vested shares outstanding at December 31, 2008	90,940	$ 30.92		
Granted	145,060	34.95		
Vested	(39,440)	27.34		
Forfeited	(10,637)	34.54		
Non-vested shares outstanding at December 31, 2009	**185,923**	**$ 34.62**	**2.6**	**$ 8,104**

[1] *The aggregate intrinsic value of restricted stock awards is calculated by multiplying the closing market price of the Company's stock on December 31, 2009 by the number of non-vested restricted stock awards outstanding.*

As shown in the table above, there were 145,060 shares of restricted stock granted to employees during 2009. During the year ended December 31, 2008, 13,000 shares of restricted stock were granted to employees with a weighted-average grant date fair value per share of $40.93. During the year ended December 31, 2007, 51,900 shares of restricted stock awards were granted with a weighted-average grant date fair value per share of $32.92. The total fair value of shares vested during 2009, 2008 and 2007 was $1.2 million, $6.5 million and $5.2 million, respectively.

Compensation expense recorded for all unvested restricted stock awards for the years ended December 31, 2009, 2008 and 2007 was $1.2 million, $1.5 million and $3.4 million, respectively. Included in 2007 restricted stock expense was $0.1 million related to the immediate expensing of shares granted to retirement-eligible employees. Unamortized expense as of December 31, 2009 for all outstanding restricted stock awards was $4.7 million and will be recognized over the next 2.6 years.

Restricted Stock Units

Restricted stock units are granted from time to time to non-employee directors of the Company. The fair value of these units is measured at the average of the high and low stock price on grant date and compensation expense is recorded immediately. These units immediately vest and are paid out when the director ceases to be a director of the Company. Due to the immediate vesting of the units and the unknown term of each director, the weighted-average remaining contractual term in years has been omitted from the table below.

The following table is a summary of restricted stock unit activity for the year ended December 31, 2009:

Restricted Stock Units	Shares	Weighted-Average Grant Date Fair Value per share	Aggregate Intrinsic Value (in thousands) [1]
Outstanding at December 31, 2008	82,015	$ 28.57	
Granted and fully vested	33,150	22.63	
Issued	-	-	
Forfeited	-	-	
Outstanding at December 31, 2009	**115,165**	**$ 26.86**	**$ 5,020**

[1] *The intrinsic value of restricted stock units is calculated by multiplying the closing market price of the Company's stock on December 31, 2009 by the number of outstanding restricted stock units.*

As shown in the table above, 33,150 restricted stock units were granted during 2009. During 2008, 16,565 restricted stock units were granted with a weighted-average grant date fair value per share of $49.17. During 2007, 24,654 restricted stock units were granted with a weighted-average grant date fair value per share of $35.49.

The compensation cost, which reflects the total fair value of these units, recorded in 2009 was $0.8 million. Compensation expense recorded during the years ended December 31, 2008 and 2007 for restricted stock units was $0.8 million and $0.9 million, respectively.

Stock Options

Stock option awards are granted with an exercise price equal to the market price (defined as the average of the high and low trading prices of the Company’s stock at the date of grant) of the Company’s stock on the date of grant. During the years ended December 31, 2009, 2008 and 2007, there were no stock options granted.

The Company uses a Black-Scholes model to calculate the fair value of stock options. Compensation cost is recorded based on a graded-vesting schedule as the options vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. Stock options have a maximum contractual term of five years. No forfeiture rate is assumed for stock options granted to directors due to the forfeiture rate history for these types of awards for this group of individuals. Compensation expense recorded during 2009 was less than $0.1 million. Compensation expense recorded for these stock options for both 2008 and 2007 was $0.1 million. There was no unamortized expense as of December 31, 2009 for stock options.

The following table is a summary of stock option activity for the years ended December 31, 2009, 2008 and 2007:

Stock Options	**2009** Shares	**2009** Weighted-Average Exercise Price	2008 Shares	2008 Weighted-Average Exercise Price	2007 Shares	2007 Weighted-Average Exercise Price
Outstanding at Beginning of Year	60,500	$ 21.69	388,950	$ 10.38	1,007,950	$ 9.03
Granted	-	-	-	-	-	-
Exercised	(10,500)	11.66	(328,450)	8.30	(619,000)	8.18
Forfeited or Expired	-	-	-	-	-	-
Outstanding at December 31 [(1)]	**50,000**	**$ 23.80**	60,500	$ 21.69	388,950	$ 10.38
Options Exercisable at December 31 [(2)]	**50,000**	**$ 23.80**	40,500	$ 20.65	348,950	$ 8.84

(1) *The intrinsic value of a stock option is the amount by which the current market value of the underlying stock exceeds the exercise price of the option. The aggregate intrinsic value of options outstanding at December 31, 2009 was $1.0 million. The weighted-average remaining contractual term is 1.1 years.*

(2) *The aggregate intrinsic value of options exercisable at December 31, 2009 was $1.0 million. The weighted-average remaining contractual term is 1.1 years.*

The total intrinsic value of options exercised during the years ended December 31, 2009, 2008 and 2007 was less than $0.1 million, $12.2 million and $19.9 million, respectively.

Stock Appreciation Rights

Beginning in 2006, the Compensation Committee has granted SARs to employees. These awards allow the employee to receive any intrinsic value over the grant date market price that may result from the price appreciation on a set number of common shares during the contractual term of seven years. All of these awards have graded-vesting features and will vest over a service period of three years, with one-third of the award becoming exercisable each year on the anniversary date of the grant. The Company calculates the fair value in the same manner as stock options, by using a Black-Scholes model.

The assumptions used in the Black-Scholes fair value calculation for SARs are as follows:

	Year Ended December 31, **2009**	2008	2007
Weighted-Average Value per Stock Appreciation Right Granted During the Period [(1)]	**$ 9.35**	$ 15.18	$ 11.26
Assumptions			
Stock Price Volatility	**50.5%**	34.4%	32.6%
Risk Free Rate of Return	**1.7%**	2.8%	4.6%
Expected Dividend	**0.5%**	0.2%	0.2%
Expected Term (in years)	**4.50**	4.25	4.00

(1) *Calculated using the Black-Scholes fair value based method.*

The expected term was derived by reviewing minimum and maximum expected term outputs from the Black-Scholes model based on award type and employee type. This term represents the period of time that awards granted are expected to be outstanding. The stock price volatility was calculated using historical closing stock price data for the Company for the period associated with the expected term through the grant date of each award. The risk free rate of return percentages are based on the continuously compounded equivalent of the US Treasury (Nominal 10) within the expected term as measured on the grant date. The expected dividend percentage assumes that the Company will continue to pay a consistent level of dividend each quarter.

The following table is a summary of SAR activity for the years ended December 31, 2009, 2008 and 2007:

Stock Appreciation Rights	2009 Shares	2009 Weighted-Average Exercise Price	2008 Shares	2008 Weighted-Average Exercise Price	2007 Shares	2007 Weighted-Average Exercise Price
Outstanding at Beginning of Year	491,930	$ 32.26	372,800	$ 27.08	265,600	$ 23.80
Granted	221,780	22.63	119,130	48.48	107,200	35.22
Exercised	(20,366)	26.19	-	-	-	-
Forfeited or Expired	(20,244)	32.19	-	-	-	-
Outstanding at December 31 [(1)]	**673,100**	**$ 29.27**	491,930	$ 32.26	372,800	$ 27.08
SARs Exercisable at December 31 [(2)]	**354,252**	**$ 28.58**	212,790	$ 25.72	88,526	$ 23.80

(1) *The intrinsic value of a SAR is the amount by which the current market value of the underlying stock exceeds the exercise price of the SAR. The aggregate intrinsic value of SARs outstanding at December 31, 2009 was $10.2 million. The weighted-average remaining contractual term is 4.6 years.*

(2) *The aggregate intrinsic value of SARs exercisable at December 31, 2009 was $5.5 million. The weighted-average remaining contractual term is 3.6 years.*

As shown in the table above, the Compensation Committee granted 221,780 SARs to employees during 2009 with an exercise price equal to the grant date market price of $22.63. The grant date fair value of these SARs was $9.35 per share. Compensation expense recorded during the years ended December 31, 2009, 2008 and 2007 for all outstanding SARs was $1.8 million, $1.7 million and $1.5 million, respectively. Included in 2009, 2008 and 2007 expense was $0.7 million, $0.5 million and $0.5 million, respectively, related to the immediate expensing of shares granted to retirement-eligible employees. Unamortized expense as of December 31, 2009 for all outstanding SARs was $0.7 million. The weighted-average period over which this compensation will be recognized is approximately 1.6 years.

Performance Share Awards

During 2009, the Compensation Committee granted three types of performance share awards to employees for a total of 785,350 performance shares. The performance period for two of the three types of these awards commenced on January 1, 2009 and ends December 31, 2011. Both of these types of awards vest on January 1, 2012.

Awards totaling 207,730 performance shares are earned, or not earned, based on the comparative performance of the Company's common stock measured against sixteen other companies in the Company's peer group over a three year performance period. The grant date per share value of the equity portion of this award was $17.63. Depending on the Company's performance, employees may receive an aggregate of up to 100% of the fair market value of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash.

Awards totaling 376,510 performance shares are earned, or not earned, based on the Company's internal performance metrics rather than performance compared to a peer group. As of December 31, 2009, 333,060 shares of this award are outstanding. The grant date per share value of this award was $22.63. These awards represent the right to receive up to 100% of the award in shares of common stock. The actual number of shares issued at the end of the performance period will be determined based on the Company's performance against three performance criteria set by the Company's Compensation Committee. An employee will earn one-third of the award granted for each internal performance metric that the Company meets at the end of the performance period. These performance criteria measure the Company's average production, average finding costs and average reserve replacement over three years. Based on the Company's probability assessment at December 31, 2009, it is considered probable that these three criteria will be met.

The third type of performance share award, totaling 201,110 performance shares, with a grant date per share value of $22.63, has a three-year graded vesting schedule, vesting one-third on each anniversary date following the date of grant, provided that the Company has $100 million or more of operating cash flow for the year preceding the vesting date. If the Company does not have $100 million or more of operating cash flow for the year preceding a vesting date, then the portion of the performance shares that would have vested on that date will be forfeited. As of December 31, 2009, it is considered probable that this performance metric will be met.

For all outstanding performance share awards granted to employees, an annual forfeiture rate ranging from 0% to 5.2% has been assumed based on the Company's history for this type of award to various employee groups.

For awards that are based on the internal metrics (performance condition) of the Company and for awards that were granted prior to the adoption of ASC 718 on January 1, 2006, fair value is measured based on the average of the high and low stock price of the Company on grant date and expense is amortized over the three year vesting period. To determine the fair value for awards that were granted after January 1, 2006 that are based on the Company's comparative performance against a peer group (market condition), the equity and liability components are bifurcated. On the grant date, the equity component was valued using a Monte Carlo binomial model and is amortized on a straight-line basis over three years. The liability component is valued at each reporting period by using a Monte Carlo binomial model.

The four primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns, correlation in movement of total shareholder return and the expected dividend. An interpolated risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for one and two year bonds (as of the reporting date) set equal to the remaining duration of the performance period. Volatility was set equal to the annualized daily volatility for the remaining duration of the performance period ending on the reporting date. Correlation in movement of total shareholder return was determined based on a correlation matrix that was created which identifies total shareholder return correlations for each pair of companies in the peer group, including the Company. The paired returns in the correlation matrix ranged from approximately 52% to approximately 86% for the Company and its peer group. The expected dividend is calculated using the total Company annual dividends paid ($0.12 for 2009) divided by the December 31, 2009 closing price of the Company's stock ($43.59). Based on these inputs discussed above, a ranking was projected identifying the Company's rank relative to the peer group for each award period.

The following assumptions were used as of December 31, 2009 for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the award was valued on the date of grant using the Monte Carlo model and this portion was not marked to market.

	December 31, 2009
Risk Free Rate of Return............................	0.5% - 1.4%
Stock Price Volatility.................................	57.7% - 70.8%
Expected Dividend....................................	0.3%

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $14.38 to $16.24 at December 31, 2009. The long-term liability for all market condition performance share awards, included in Other Liabilities in the Consolidated Balance Sheet, at December 31, 2009 and 2008 was $1.1 million and $0.3 million, respectively. The short-term liability, included in Accrued Liabilities in the Consolidated Balance Sheet, at December 31, 2009 and 2008, for certain market condition performance share awards was $2.4 million and $2.5 million, respectively.

On December 31, 2009, the performance period ended for two types of performance shares awarded in 2007, including 150,100 shares measured based on internal performance metrics of the Company and 92,400 shares measured based on the Company's performance against a peer group. For the internal performance metric awards, the calculation of the average of the three years of the Company's three internal performance metrics was completed in the first quarter of 2010 and was certified by the Compensation Committee in February 2010. As the Company achieved the three internal performance metrics, 100% of the award, valued at $5.3 million based on the average of the high and low stock price on the grant date, was payable in 150,100 shares of common stock. For the peer group awards, due to the ranking of the Company compared to its peers in its predetermined peer group, 100% of the award, valued at $2.8 million based on the Monte Carlo value on the grant date, was payable in 92,400 shares of common stock and an additional 33%, equal to one-third of the total value of the award, calculated by using the high and low stock price on December 31, 2009 multiplied by the number of performance shares earned, or $1.3 million, was payable in cash. This cash amount was paid in January 2010. The calculation of the award payout was certified by the Compensation Committee on January 4, 2010. The vesting of both types of shares discussed above will be reported in the first quarter of 2010.

The following table is a summary of performance share award activity for the year ended December 31, 2009:

Performance Share Awards	**Shares**	**Weighted-Average Grant Date Fair Value per share (1)**	**Weighted-Average Remaining Contractual Term (in years)**	**Aggregate Intrinsic Value (in thousands) (2)**
Non-vested shares outstanding at December 31, 2008	963,775	$ 35.17		
Granted	785,350	21.30		
Vested	(332,642)	25.31		
Forfeited	(120,090)	37.39		
Non-vested shares outstanding at December 31, 2009	**1,296,393**	**$ 29.74**	**1.9**	**$ 56,510**

(1) *The fair value figures in this table represent the fair value of the equity component of the performance share awards.*

(2) *The aggregate intrinsic value of performance share awards is calculated by multiplying the closing market price of the Company's stock on December 31, 2009 by the number of non-vested performance share awards outstanding.*

Of the performance shares that vested during 2009 shown in the table above, 105,800 shares were granted in 2006. These shares (valued at $1.7 million) were measured based on the Company's performance against a peer group and were awarded in addition to cash of $1.8 million. A total of 155,800 shares (valued at $3.8 million) measured based on internal performance metrics of the Company were also awarded. During 2009, 60,740 shares vested (valued at $2.5 million) which represents one-third of the three-year graded vesting schedule performance share awards granted in 2008 and 2007 with a grant date per share value of $48.48 and $35.22, respectively. In addition, 10,302 performance shares vested as a result of early vesting schedules for certain employees. These awards met the performance criteria that the Company had positive operating income for 2008 and 2007.

During the year ended December 31, 2008, 383,065 performance share awards were granted with a weighted-average grant date fair value per share of $46.63. Of the 249,990 performance shares that vested during 2008, 207,800 shares were granted in 2005 and were market condition awards which provided that employees may receive an aggregate of up to 100% of a share of common stock payable in common stock plus up to 100% of the fair market value of a share of common stock payable in cash. As a result of the Company's ranking on the vesting date, 100% of the shares were paid in common stock and an additional 67% of the fair market value of each share of common stock, or $7.9 million, was paid in cash during the second quarter of 2008. Another 30,790 shares vested during 2008 and represent one-third of the three-year graded vesting schedule performance share awards granted in 2007 with a grant date per share value of $35.22. These awards met the performance criteria that the Company had positive operating income for the 2007 year. The remaining 11,400 shares vested as a result of the death of an employee of the Company.

During the year ended December 31, 2007, 387,100 performance share awards were granted with a weighted-average grant date fair value per share of $34.08. During the year ended December 31, 2007, 450,000 performance shares vested related to the performance period commencing on January 1, 2004 and ending on December 31, 2007.

During 2009, 2008 and 2007, 120,090, 37,000 and 9,500 performance shares, respectively, were forfeited.

As of December 31, 2009, 225,800 shares of the Company's common stock representing vested performance share awards were deferred into the Rabbi Trust Deferred Compensation Plan. A total of 30,600 shares were sold out of the plan in 2009. During 2009, an increase to the rabbi trust deferred compensation liability of $4.6 million was recognized, representing the increase in the closing price of shares primarily related to the Company's common stock from December 31, 2008 to December 31, 2009 in addition to a reduction in the liability due to shares that were sold out of the rabbi trust. This increase in stock-based compensation expense was included in General and Administrative expense in the Consolidated Statement of Operations.

Total unamortized compensation cost related to the equity component of performance shares at December 31, 2009 was $13.2 million and will be recognized over the next 1.9 years, computed by using the weighted-average of the time in years remaining to recognize unamortized expense. Total compensation cost recognized for both the equity and liability components of all performance share awards as well as expense related to the shares deferred into the rabbi trust during the years ended December 31, 2009, 2008 and 2007 was $20.1 million, $14.5 million and $9.4 million, respectively.

Supplemental Employee Incentive Plans

On January 16, 2008, the Company's Board of Directors adopted a Supplemental Employee Incentive Plan. The plan was intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company's common stock reaches a specified trading price.

The bonus payout was triggered if, for any 20 trading days (which need not be consecutive) that fell within a period of 60 consecutive trading days occurring on or before November 1, 2011, the closing price per share of the Company's common stock equaled or exceeded the price goal of $60 per share. In such event, the 20th trading day on which such price condition was attained is the "Final Trigger Date." Under the plan, each eligible employee would receive a minimum distribution of 50% of his or her base salary as of the Final Trigger Date, as adjusted for persons hired after December 31, 2007 to reflect calendar quarters of service, reduced by any interim distribution previously paid to such employee upon the achievement of the interim price goal discussed below. The Committee was authorized, in its discretion, to allocate to eligible employees additional distributions, subject to limitations of the plan.

The plan also provided that an interim distribution would be paid to eligible employees upon achieving the interim price goal of $50 per share prior to December 31, 2009. Interim distributions were determined as described above except that interim distributions were based on 10%, rather than 50%, of salary.

On the January 16, 2008 adoption date of the plan, the Company's closing stock price was $40.71. On April 8, 2008 and subsequently on June 2, 2008, the Company achieved the interim and final target goals and total distributions of $15.7 million were paid in 2009. No further distributions will be made under this plan.

On July 24, 2008, the Company's Board of Directors adopted a second Supplemental Employee Incentive Plan ("Plan II"). Plan II is also intended to provide a compensation tool tied to stock market value creation to serve as an incentive and retention vehicle for full-time non-officer employees by providing for cash payments in the event the Company's common stock reaches a specified trading price.

Plan II provides for a final payout if, for any 20 trading days (which need not be consecutive) that fall within a period of 60 consecutive trading days ending on or before June 20, 2012, the closing price per share of the Company's common stock equals or exceeds the price goal of $105 per share. In such event, the 20th trading day on which such price condition is attained is the "Final Trigger Date." The price goal is subject to adjustment by the Compensation Committee to reflect any stock splits, stock dividends or extraordinary cash distributions to stockholders. Under Plan II, each eligible employee may receive (upon approval by the Compensation Committee) a distribution of 50% of his or her base salary as of the Final Trigger Date (or 30% of base salary if the Company paid interim distributions upon the achievement of the interim price goal discussed below).

Plan II provides that a distribution of 20% of an eligible employee's base salary as of the Interim Trigger Date will be made (upon approval by the Compensation Committee) upon achieving the interim price goal of $85 per share on or before June 30, 2010. Interim distributions are determined as described above except that interim distributions will be based on 20%, rather than 50%, of salary. The Compensation Committee can increase the 50% or 20% payment as it applies to any employee.

Payments under either the interim or final distribution will occur as follows:

- 25% of the total distribution paid on the 15th business day following the interim or final trigger date, as applicable, and
- 75% of the total distribution paid based on the following deferred payment dates in the table below:

Period During which the Trigger Date Occurs	Deferred Payment Date
July 1, 2008 to June 30, 2009	The business day on or next following the 18 month anniversary of the applicable Trigger Date
July 1, 2009 to June 30, 2010	The business day on or next following the 12 month anniversary of the applicable Trigger Date
July 1, 2010 to December 31, 2010	The business day on or next following the 6 month anniversary of the applicable Trigger Date
January 1, 2011 to June 30, 2012	No deferral; entire payment is made on the 15th business day following the applicable Trigger Date

Any deferred portion will only be paid if the participant is employed by the Company, or has terminated employment by reason of retirement, death or disability (as provided in Plan II). Payments are subject to certain other restrictions contained in Plan II.

These awards under both plans discussed above have been accounted for as liability awards under ASC 718. Total expense for 2009 and 2008 was $1.2 million and $15.9 million, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations.

11. Financial Instruments

Adoption of ASC 820

In September 2006, the FASB issued ASC 820, "Fair Value Measurements and Disclosures," which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by GAAP to be measured at fair value. ASC 820 discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. ASC 820 was effective for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. In February 2008, the FASB granted a one year deferral (to fiscal years beginning after November 15, 2008, and interim periods within those fiscal years) for certain non-financial assets and liabilities to comply with ASC 820. Effective January 1, 2009, the Company applied all of the provisions of ASC 820 and there was not a material impact on the Company's financial statements except for the Company's impairment of oil and gas properties (refer to Note 2). In the future, areas that could cause an impact would primarily be limited to asset impairments, including long-lived assets, asset retirement obligations and assets acquired and liabilities assumed in a business combination, if any.

As defined in ASC 820, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The transaction is based on a hypothetical transaction in the principal or most advantageous market considered from the perspective of the market participant that holds the asset or owes the liability.

The valuation techniques that can be used under ASC 820 are the market approach, income approach or cost approach. The market approach uses prices and other information for market transactions involving identical or comparable assets or liabilities, such as matrix pricing. The income approach uses valuation techniques to convert future amounts to a single discounted present value amount based on current market conditions about those future amounts, such as present value techniques, option pricing models (i.e. Black-Scholes model) and binomial models (i.e. Monte-Carlo model). The cost approach is based on current replacement cost to replace an asset.

The Company utilizes market data or assumptions that market participants who are independent, knowledgeable and willing and able to transact would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company attempts to utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. The Company is able to classify fair value balances based on the observability of those inputs. ASC 820 establishes a formal fair value hierarchy based on the inputs used to measure fair value. The hierarchy gives the highest priority to level 1 measurements and the lowest priority to level 3 measurements, and accordingly, level 1 measurements should be used whenever possible.

The three levels of the fair value hierarchy as defined by ASC 820 are as follows:

- Level 1: Valuations utilizing quoted, unadjusted prices for identical assets or liabilities in active markets that the Company has the ability to access. This is the most reliable evidence of fair value and does not require a significant degree of judgment. Examples include exchange-traded derivatives and listed equities that are actively traded.

- Level 2: Valuations utilizing quoted prices in markets that are not considered to be active or financial instruments for which all significant inputs are observable, either directly or indirectly for substantially the full term of the asset or liability. Financial instruments that are valued using models or other valuation methodologies are included. Models used should primarily be industry-standard models that consider various assumptions and economic measures, such as interest rates, yield curves, time value, volatilities, contract terms, current market prices, credit risk or other market-corroborated inputs. Examples include most over-the-counter derivatives (non-exchange traded), physical commodities, most structured notes and municipal and corporate bonds.

- Level 3: Valuations utilizing significant, unobservable inputs. This provides the least objective evidence of fair value and requires a significant degree of judgment. Inputs may be used with internally developed methodologies and should reflect an entity's assumptions using the best information available about the assumptions that market participants would use in pricing an asset or liability. Examples include certain corporate loans, real-estate and private equity investments and long-dated or complex over-the-counter derivatives.

Depending on the particular asset or liability, input availability can vary depending on factors such as product type, longevity of a product in the market and other particular transaction conditions. In some cases, certain inputs used to measure fair value may be categorized into different levels of the fair value hierarchy. For disclosure purposes under ASC 820, the lowest level that contains significant inputs used in valuation should be chosen. In accordance with ASC 820, the Company has classified its assets and liabilities into these levels depending upon the data relied on to determine the fair values.

The following fair value hierarchy table presents information about the Company's assets and liabilities measured at fair value on a recurring basis as of December 31, 2009:

(In thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Assets				
Rabbi Trust Deferred Compensation Plan........	$ 10,031	$ -	$ -	**$ 10,031**
Derivative Contracts.......................................	-	-	114,686	**114,686**
Total Assets...	$ 10,031	$ -	$ 114,686	**$ 124,717**
Liabilities				
Rabbi Trust Deferred Compensation Plan........	$ 19,087	$ -	$ -	**$ 19,087**
Derivative Contracts.......................................	-	-	2,379	**2,379**
Total Liabilities..	$ 19,087	$ -	$ 2,379	**$ 21,466**

The Company's investments associated with its Rabbi Trust Deferred Compensation Plan consist of mutual funds that are publicly traded and for which market prices are readily available. In addition, the Rabbi Trust Deferred Compensation Liability includes the value of deferred shares of the Company's common stock which is publicly traded and for which current market prices are readily available.

The determination of the fair values above incorporates various factors required under ASC 820. These factors include not only the credit standing of the counterparties involved in transactions with the Company resulting in receivables on the Company's Consolidated Balance Sheet, but also the impact of the Company's nonperformance risk on its liabilities.

For further information about the Company's pension plan assets, refer to Note 5 of the Notes to the Consolidated Financial Statements.

The following table sets forth a reconciliation of changes for year ended December 31, 2009 in the fair value of financial assets and liabilities classified as Level 3 (excluding pension plan assets which are disclosed in Note 5) in the fair value hierarchy:

(In thousands)	December 31, 2009	December 31, 2008
Balance at beginning of period...	**$ 355,202** (1)	$ 7,272 (2)
Total Gains or (Losses) (Realized or Unrealized):		
Included in Earnings (3)	**393,073**	13,021
Included in Other Comprehensive Income..................	**(240,941)**	347,930
Purchases, Issuances and Settlements..............................	**(395,027)**	(13,021)
Transfers In and/or Out of Level 3...................................	**-**	-
Balance at end of period...	**$ 112,307**	$ 355,202

(1) *Balance was entirely comprised of derivative assets.*

(2) *Balance was comprised of derivative assets of $12.7 million and derivative liabilities of $5.4 million.*

(3) *A loss of $2.0 million for the year ended December 31, 2009 was unrealized and included in Natural Gas Production Revenues in the Statement of Operations. All gains included in earnings for the year ended December 31, 2008 were realized.*

The derivative contracts were measured based on quotes from the Company's counterparties. Such quotes have been derived using a Black-Scholes model that considers various inputs including current market and contractual prices for the underlying instruments, quoted forward prices for natural gas and crude oil, volatility factors and interest rates, such as a LIBOR curve for a similar length of time as the derivative contract term. These estimates are compared to multiple quotes obtained from counterparties for reasonableness. The Company measured the nonperformance risk of its counterparties by reviewing credit default swap spreads for the various financial institutions in which it has derivative transactions. The resulting reduction to the net receivable derivative contract position was $0.2 million. In times where the Company has net derivative contract liabilities, the nonperformance risk of the Company is evaluated using a market credit spread provided by the Company's bank.

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the Consolidated Balance Sheet for cash and cash equivalents, accounts receivable and accounts payable approximate fair value. The fair value of long-term debt is the estimated cost to acquire the debt, including a credit spread for the difference between the issue rate and the year end market rate. The credit spread is the Company's default or repayment risk. The credit spread (premium or discount) is determined by comparing the Company's fixed-rate notes to new issuances (secured and unsecured) and secondary trades of similar size and credit statistics for both public and private debt. The fair value of all of the notes, excluding the credit facility, is based on interest rates currently available to the Company. The credit facility approximates fair value because this instrument bears interest at rates based on current market rates.

The Company uses available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with ASC 825-10-50, "*Financial Instruments – Overall – Disclosure,*" as well as ASC 820, "*Fair Value Measurements and Disclosures,*" and does not impact the Company's financial position, results of operations or cash flows.

	December 31, 2009		December 31, 2008	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Long-Term Debt	**$ 805,000**	**$ 863,559**	$ 867,000	$ 807,508
Current Maturities	**-**	**-**	(35,857)	(35,796)
Long-Term Debt, excluding Current Maturities	**$ 805,000**	**$ 863,559**	$ 831,143	$ 771,712

Derivative Instruments and Hedging Activity

In March 2008, the FASB issued guidance and amended the disclosure requirements prescribed in ASC 815, "Derivatives and Hedging." Entities are now required to provide greater transparency about how and why the entity uses derivative instruments, how the instruments and related hedged items are accounted for under ASC 815 and how the instruments and related hedged items affect the financial position, results of operations and cash flows of the entity. The Company adopted these new disclosure requirements effective January 1, 2009. A tabular format including the fair value of derivative instruments and their gains and losses, disclosure about credit risk-related derivative features and cross-referencing within the footnotes are also new requirements.

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. The Company's credit agreement restricts the ability of the Company to enter into commodity hedges other than to hedge or mitigate risks to which the Company has actual or projected exposure or as permitted under the Company's risk management policies and not subjecting the Company to material speculative risks. All of the Company's derivatives are used for risk management purposes and are not held for trading purposes. As of December 31, 2009, the Company had twelve cash flow hedges open: eleven natural gas price swap arrangements and one crude oil price swap arrangement. During 2009, the Company entered into six new derivative contracts covering anticipated natural gas production for 2012. These natural gas basis swaps did not qualify for hedge accounting under ASC 815. These natural gas basis swaps mitigate the risk associated with basis differentials that may expand or increase over time, thus reducing the exposure and risk of basis fluctuations.

As of December 31, 2009, the Company had the following outstanding commodity derivatives:

Commodity	Derivative Type	Weighted-Average Contract Price		Volume		Contract Period
Derivatives designated as Hedging Instruments under ASC 815						
Natural Gas	Swap	$9.30	per Mcf	35,856	Mmcf	2010
Crude Oil	Swap	$125.00	per Bbl	365	Mbbl	2010
Derivatives not qualifying as Hedging Instruments under ASC 815						
Natural Gas	Basis Swap	$(0.27)	per Mcf	16,123	Mmcf	2012

The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income / (Loss) in Stockholders' Equity in the Balance Sheet. The ineffective portion of the change in the fair value of derivatives designated as hedges, and the change in fair value of derivatives not qualifying as hedges, are recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate.

The following schedules reflect the fair values of derivative instruments on the Company's consolidated financial statements as of December 31, 2009:

	Asset Derivatives		Liability Derivatives	
(In thousands)	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Derivatives designated as Hedging Instruments under ASC 815				
Natural Gas Commodity Contracts	Current Derivative Contracts	$ 99,151	Accrued Liabilities	$ (425)
Crude Oil Commodity Contracts	Current Derivative Contracts	15,535	-	-
		$ 114,686		**$ (425)**
Derivatives not qualifying as Hedging Instruments under ASC 815				
Natural Gas Commodity Basis Contracts	Long-Term Derivative Contracts	-	Other Liabilities	(1,954)
		$ 114,686		**$ (2,379)**

At December 31, 2009, a $114.3 million ($71.9 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income / (Loss). For the natural gas commodity basis contracts that were not designated as hedging instruments, a $2.0 million unrealized loss was recorded in the Consolidated Statement of Operations as a component of Natural Gas Production Revenue for the year ended December 31, 2009.

Effect of derivative instruments on the Consolidated Statement of Operations

(In thousands)	Amount of Gain Recognized in OCI on Derivative (Effective Portion)	Location of Gain Reclassified from Accumulated OCI into Income (Effective Portion)	Amount of Gain Reclassified from Accumulated OCI into Income (Effective Portion)	Location of Gain Recognized in Income on Derivative (Ineffective Portion and Amount Excluded from Effectiveness Testing)
Derivatives designated as Hedging Instruments under ASC 815				
Natural Gas Commodity Contracts	$ 98,726	Natural Gas Production Revenues	$ 371,915	-
Crude Oil Commodity Contracts	15,535	Crude Oil and Condensate Revenues	23,112	-
	$ 114,261		**$ 395,027**	

(In thousands)	Location of Loss Recognized in Income on Derivative	Amount of Loss Recognized in Income on Derivative
Derivatives not qualifying as Hedging Instruments under ASC 815		
Natural Gas Commodity Contracts	Natural Gas Production Revenues	**$ (1,954)**

Based upon estimates at December 31, 2009, the Company would expect to reclassify from Other Comprehensive Income to the Consolidated Statement of Operations over the next 12 months $71.9 million in after-tax income associated with its commodity hedges. This reclassification represents the net short-term receivable (after the impact of taxes) associated with open positions currently not reflected in earnings at December 31, 2009 related to anticipated 2010 production.

Investment in Equity Securities Carried at Cost

In April 2009 a private Canadian company purchased for cash and common stock substantially all of the Company's Canadian assets. The common stock is carried at cost of $20.6 million. The Company estimated the fair value of its investment to be $42.8 million at December 31, 2009. The common stock value received in a recent private placement of the Canadian company's common stock was used to estimate the fair value of the investment.

Market Risk

The Company's primary market risk is exposure to oil and natural gas prices. Realized prices are mainly driven by worldwide prices for oil and spot market prices for North American natural gas production. Commodity prices are volatile and unpredictable.

The debt and equity markets have experienced unfavorable conditions, which may affect the Company's ability to access those markets. As a result of the volatility and disruption in the capital markets and the Company's increased level of borrowings, it may experience increased costs associated with future borrowings and debt issuances. At this time, the Company does not believe its liquidity has been materially affected by the recent market events. The Company will continue to monitor events and circumstances surrounding each of its lenders in its revolving credit facility.

Credit Risk

Although notional contract amounts are used to express the volume of natural gas price agreements, the amounts that can be subject to credit risk in the event of non-performance by third parties are substantially smaller. The Company does not anticipate any material impact on its financial results due to non-performance by the third parties.

In 2009, two customers accounted for approximately 13% and 11%, respectively, of the Company's total sales. In 2008, one customer accounted for approximately 16% of the Company's total sales. In 2007, no customer accounted for more than 10% of the Company's total sales.

12. Earnings per Common Share

Effective January 1, 2009, the Company adopted amendments that the FASB made to ASC 260, "Earnings Per Share," regarding determining whether instruments granted in share-based payment transactions are participating securities. Under these amendments, unvested share-based payment awards that contain nonforfeitable rights to dividends or dividend equivalents, whether they are paid or unpaid, are considered participating securities and should be included in the computation of earnings per share pursuant to the two-class method. These amendments became effective financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those years. In addition, all prior period earnings per share data presented are required to be retrospectively adjusted. Upon adoption, basic earnings per share (EPS) is required to be computed using the two-class method prescribed in ASC 260. The two-class method is an earnings allocation formula that treats a participating security as having rights to earnings that would otherwise have been available to common shareholders. ASC 260 defines participating securities as "securities that may participate in dividends with common stocks according to a predetermined formula." ASC 260 provides that its provisions need not be applied to immaterial items. The Company has concluded that there are no material items to consider for purposes of its shares outstanding and EPS calculations, and the treasury stock method will continue to be used, as described below.

Basic EPS is computed by dividing net income (the numerator) by the weighted-average number of common shares outstanding for the period (the denominator). Diluted EPS is similarly calculated except that the denominator is increased using the treasury stock method to reflect the potential dilution that could occur if stock options and stock awards outstanding at the end of the applicable period were exercised for common stock.

The following is a calculation of basic and diluted weighted-average shares outstanding for the years ended December 31, 2009, 2008 and 2007:

	December 31,		
	2009	2008	2007 [1]
Weighted-Average Shares - Basic	**103,615,971**	100,736,562	96,977,634
Dilution Effect of Stock Options and Awards at End of Period	**1,066,776**	989,936	1,152,673
Weighted-Average Shares - Diluted	**104,682,747**	101,726,498	98,130,307
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**260,818**	258,074	21,639

[1] *Reflects the 2-for-1 split of the Company's common stock (refer to Note 9).*

13. Accumulated Other Comprehensive Income / (Loss)

Changes in the components of accumulated other comprehensive income / (loss), net of taxes, for the years ended December 31, 2009, 2008 and 2007 were as follows:

Accumulated Other Comprehensive Income / (Loss), net of taxes *(In thousands)*	**Net Gains / (Losses) on Cash Flow Hedges**	**Defined Benefit Pension and Postretirement Plans**	**Foreign Currency Translation Adjustment**	**Total**
Balance at December 31, 2006................................	$ 51,239	$ (14,168)	$ 89	$ 37,160
Net change in unrealized gains on cash flow hedges, net of taxes of $28,024.........................	(46,686)	-	-	(46,686)
Net change in defined benefit pension and postretirement plans, net of taxes of $(100)..	-	141	-	141
Change in foreign currency translation adjustment, net of taxes of $(5,072)................	-	-	8,491	8,491
Balance at December 31, 2007................................	$ 4,553	$ (14,027)	$ 8,580	$ (894)
Net change in unrealized gain on cash flow hedges, net of taxes of $(129,415)...................	218,515	-	-	218,515
Net change in defined benefit pension and postretirement plans, net of taxes of $9,235......	-	(15,581)	-	(15,581)
Change in foreign currency translation adjustment, net of taxes of $9,292..................	-	-	(15,614)	(15,614)
Balance at December 31, 2008................................	$ 223,068	$ (29,608)	$ (7,034)	$ 186,426
Net change in unrealized gain on cash flow hedges, net of taxes of $89,745.........................	(151,196)	-	-	(151,196)
Net change in defined benefit pension and postretirement plans, net of taxes of $(162)......	-	259	-	259
Change in foreign currency translation adjustment, net of taxes of $(4,116)................	-	-	6,947	6,947
Balance at December 31, 2009..............................	**$ 71,872**	**$ (29,349)**	**$ (87)**	**$ 42,436**

CABOT OIL & GAS CORPORATION

SUPPLEMENTAL OIL AND GAS INFORMATION (UNAUDITED)

Oil and Gas Reserves

Users of this information should be aware that the process of estimating quantities of "proved" and "proved developed" natural gas and crude oil reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. As a result, revisions to existing reserve estimates may occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the subjective decisions and variances in available data for various reservoirs make these estimates generally less precise than other estimates included in the financial statement disclosures.

Proved reserves represent estimated quantities of natural gas, crude oil and condensate that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions and government regulations in effect when the estimates were made.

Proved developed reserves are proved reserves expected to be recovered through existing wells, equipment and operating methods when the estimates were made and through installed extraction equipment and infrastructure operational if the extraction is by means not involving a well.

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

Estimates of total proved reserves at December 31, 2009, 2008, and 2007 were based on studies performed by the Company's petroleum engineering staff. The 2009 estimates were computed using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during 2009, as prescribed under the revised rules codified in ASC 932, “Extractive Activities—Oil and Gas.” The 2008 and 2007 estimates were computed based on year end prices for oil, natural gas, and natural gas liquids. The estimates were reviewed by Miller and Lents, Ltd., who indicated in their letter dated February 12, 2010, that based on their investigation and subject to the limitations described in their letter, they believe the results of those estimates and projections were reasonable in the aggregate.

No major discovery or other favorable or unfavorable event after December 31, 2009, is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

As of December 31, 2009, the Company adopted the FASB’s authoritative guidance related to oil and gas reserve estimation and disclosures in conjunction with the year-end reserve reporting as a change in accounting principle that is inseparable from a change in accounting estimate. The impact of the adoption of this guidance on the Company’s financial statements is not practicable to estimate due to the challenges associated with computing a cumulative effect of adoption by preparing reserve reports under both the old and new guidance.

The following tables illustrate the Company's net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by the Company's engineering staff. All reserves are located within the continental United States and, to a lesser extent, Canada in 2008 and 2007.

(Millions of cubic feet)	Natural Gas December 31, 2009	2008	2007
Proved Reserves:			
Beginning of Year	**1,885,993**	1,559,953	1,368,293
Revisions of Prior Estimates [1]	**(193,767)**	(47,745)	2,604
Extensions, Discoveries and Other Additions	**459,612**	297,089	265,830
Production	**(97,914)**	(90,425)	(80,475)
Purchases of Reserves in Place	**9**	167,262	3,701
Sales of Reserves in Place	**(40,771)**	(141)	-
End of Year	**2,013,162**	1,885,993	1,559,953
Proved Developed Reserves:			
Beginning of Year	**1,308,155**	1,133,937	996,850
End of Year	**1,288,169**	1,308,155	1,133,937
Percentage of Reserves Developed	**64.0%**	69.4%	72.7%

[1] *In 2009 the Company had a net downward revision of 193.8 Bcfe primarily due to (i) downward revisions of 101.1 Bcfe due to lower 2009 oil and natural gas prices compared to 2008 and (ii) downward revisions of 114.9 Bcfe due to the removal of proved undeveloped reserves scheduled for development beyond five years primarily due to the application of the SEC's new oil and gas reserve calculation methodology, partially offset by 22.2 Bcfe of positive performance revisions.*

(Thousands of barrels)	Liquids December 31, 2009	2008	2007
Proved Reserves:			
Beginning of Year	**9,341**	9,328	7,973
Revisions of Prior Estimates	**(1,062)**	(1,593)	771
Extensions, Discoveries and Other Additions	**544**	1,134	1,381
Production	**(844)**	(794)	(830)
Purchases of Reserves in Place	**-**	1,268	33
Sales of Reserves in Place	**(196)**	(2)	-
End of Year	**7,783**	9,341	9,328
Proved Developed Reserves:			
Beginning of Year	**6,728**	7,026	5,895
End of Year	**6,082**	6,728	7,026
Percentage of Reserves Developed	**78.1%**	72.0%	75.3%

Capitalized Costs Relating to Oil and Gas Producing Activities

The following table illustrates the total amount of capitalized costs relating to natural gas and crude oil producing activities and the total amount of related accumulated depreciation, depletion and amortization.

	December 31,		
(In thousands)	**2009**	2008	2007
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities.................	**$ 4,905,424**	$ 4,465,630	$ 3,007,849
Aggregate Accumulated Depreciation, Depletion and Amortization.........................	**1,550,837**	1,331,243	1,100,369
Net Capitalized Costs	**3,354,587**	3,134,387	1,907,480

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

Costs incurred in property acquisition, exploration and development activities were as follows:

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Property Acquisition Costs, Proved.............	**$ 394**	$ 605,860	$ 3,982
Property Acquisition Costs, Unproved	**145,681**	152,666	22,186
Exploration Costs (1)	**81,505**	89,020	70,242
Development Costs......................................	**365,831**	594,221	494,204
Total Costs..	**$ 593,411**	$ 1,441,767	$ 590,614

(1) *Includes administrative exploration costs of $14,405, $14,766 and $13,761 for the years ended December 31, 2009, 2008 and 2007, respectively.*

Results of Operations for Producing Activities

The results of operations for the Company's oil and gas producing activities were as follows:

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Operating Revenues..	**$ 800,464**	$ 829,208	$ 637,195
Costs and Expenses			
Production...	**121,087**	140,763	116,020
Other Operating..	**54,700**	59,348	40,620
Exploration (1)	**50,784**	31,200	39,772
Depreciation, Depletion and Amortization...........	**265,402**	259,399	164,613
Total Costs and Expenses.................................	**491,973**	490,710	361,025
Income Before Income Taxes.......................................	**308,491**	338,498	276,170
Provision for Income Taxes..	**113,234**	124,528	100,755
Results of Operations..	**$ 195,257**	$ 213,970	$ 175,415

(1) *Includes administrative exploration costs of $14,405, $14,766 and $13,761 for the years ended December 31, 2009, 2008 and 2007, respectively.*

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information has been developed utilizing ASC 932-235-50, "Extractive Activities – Oil and Gas – Notes to Financial Statements - Disclosure," procedures and based on natural gas and crude oil reserve and production volumes estimated by the Company's engineering staff. It can be used for some comparisons, but should not be the only method used to evaluate the Company or its performance. Further, the information in the following table may not represent realistic assessments of future cash flows, nor should the Standardized Measure of Discounted Future Net Cash Flows be viewed as representative of the current value of the Company.

The Company believes that the following factors should be taken into account when reviewing the following information:

- Future costs and selling prices will probably differ from those required to be used in these calculations.
- Due to future market conditions and governmental regulations, actual rates of production in future years may vary significantly from the rate of production assumed in the calculations.
- Selection of a 10% discount rate is arbitrary and may not be a reasonable measure of the relative risk that is part of realizing future net oil and gas revenues.
- Future net revenues may be subject to different rates of income taxation.

Under the Standardized Measure, future cash inflows for 2009 were estimated by using the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first day of the month price for each month during 2009, as prescribed under the revised rules codified in ASC 932 that the Company adopted on January 1, 2010, and by applying year end oil and gas prices to the estimated future production of year end proved reserves for the 2008 and 2007 years.

The average prices (adjusted for basis and quality differentials) related to proved reserves at December 31, 2009, 2008 and 2007 for natural gas ($ per Mcf) were $3.84, $5.66 and $6.91, respectively, and for oil ($ per Bbl) were $55.41, $40.15 and $94.94, respectively. Future cash inflows were reduced by estimated future development and production costs based on year end costs to arrive at net cash flow before tax. Future income tax expense was computed by applying year end statutory tax rates to future pretax net cash flows, less the tax basis of the properties involved. ASC 932-235-50 requires the use of a 10% discount rate.

Management does not use only the following information when making investment and operating decisions. These decisions are based on a number of factors, including estimates of proved reserves, and varying price and cost assumptions considered more representative of a range of anticipated economic conditions.

Standardized Measure is as follows:

	Year Ended December 31,		
(In thousands)	**2009**	2008	2007
Future Cash Inflows	**$ 8,170,009**	$ 11,050,932	$ 11,671,078
Future Production Costs	**(2,353,974)**	(3,018,154)	(2,690,695)
Future Development Costs	**(1,234,203)**	(1,354,780)	(909,374)
Future Income Tax Expenses	**(1,089,282)**	(1,891,928)	(2,684,271)
Future Net Cash Flows	**3,492,550**	4,786,070	5,386,738
10% Annual Discount for Estimated Timing of Cash Flows	**(1,860,815)**	(2,726,115)	(3,216,087)
Standardized Measure of Discounted Future Net Cash Flows	**$ 1,631,735**	$ 2,059,955	$ 2,170,651

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following is an analysis of the changes in the Standardized Measure:

(In thousands)	Year Ended December 31, 2009	2008	2007
Beginning of Year	**$ 2,059,955**	$ 2,170,651	$ 1,476,250
Discoveries and Extensions, Net of Related Future Costs	**381,691**	341,156	430,918
Net Changes in Prices and Production Costs	**(861,939)**	(692,803)	864,630
Accretion of Discount	**236,520**	300,766	201,023
Revisions of Previous Quantity Estimates	**(159,531)**	(69,788)	13,452
Timing and Other	**(104,117)**	(157,194)	(136,360)
Development Costs Incurred	**109,384**	157,194	136,781
Sales and Transfers, Net of Production Costs	**(286,594)**	(688,657)	(521,558)
Net Purchases / (Sales) of Reserves in Place	**(38,730)**	166,873	8,548
Net Change in Income Taxes	**295,096**	531,757	(303,033)
End of Year	**$ 1,631,735**	$ 2,059,955	$ 2,170,651

CABOT OIL & GAS CORPORATION

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
2009					
Operating Revenues	**$ 233,939**	**$ 204,824**	**$ 207,021**	**$ 233,492**	**$ 879,276**
Impairment of Oil & Gas Properties and Other Assets [1]	**-**	**-**	**-**	**17,622**	**17,622**
Operating Income [2]	**89,897**	**54,239**	**74,723**	**63,410**	**282,269**
Net Income [2]	**47,580**	**25,502**	**38,897**	**36,364**	**148,343**
Basic Earnings per Share	**0.46**	**0.25**	**0.38**	**0.34**	**1.43**
Diluted Earnings per Share	**0.46**	**0.24**	**0.37**	**0.35**	**1.42**
2008					
Operating Revenues	$ 219,651	$ 248,854	$ 244,820	$ 232,466	$ 945,791
Impairment of Oil & Gas Properties and OtherAssets [1]	-	-	-	35,700	35,700
Operating Income	76,072	94,086	114,717	87,137	372,012
Net Income	45,975	54,625	66,990	43,700	211,290
Basic Earnings per Share	0.47	0.55	0.65	0.42	2.10
Diluted Earnings per Share	0.46	0.55	0.64	0.42	2.08

(1) *For discussion of impairment of oil and gas properties, refer to Note 2 of the Notes to the Consolidated Financial Statements.*

(2) *Operating Income and Net Income in the first and second quarters of 2009 contain a $12.7 million gain on the disposition of Thornwood properties and a $16.0 million loss on the sale of Canadian properties, respectively.*

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures and Changes in Internal Control over Financial Reporting

As of December 31, 2009, the Company carried out an evaluation, under the supervision and with the participation of the Company's management, including the Company's Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of the Company's disclosure controls and procedures pursuant to Rules 13a-15 and 15d-15 of the Securities Exchange Act of 1934 (the "Exchange Act"). Based upon that evaluation, the Chief Executive Officer and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective, in all material respects, with respect to the recording, processing, summarizing and reporting, within the time periods specified in the Commission's rules and forms, of information required to be disclosed by the Company in the reports that it files or submits under the Exchange Act.

There were no changes in the Company's internal control over financial reporting that occurred during the fourth quarter that has materially affected, or is reasonably likely to materially effect, the Company’s internal control over financial reporting.

Management’s Report on Internal Control over Financial Reporting

The management of Cabot Oil & Gas Corporation is responsible for establishing and maintaining adequate internal control over financial reporting. Cabot Oil & Gas Corporation’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. 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.

Cabot Oil & Gas Corporation’s management assessed the effectiveness of the Company’s internal control over financial reporting as of December 31, 2009. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control-Integrated Framework. Based on our assessment we have concluded that, as of December 31, 2009, the Company’s internal control over financial reporting is effective based on those criteria.

The effectiveness of Cabot Oil & Gas Corporation’s internal control over financial reporting as of December 31, 2009, has been audited by Pricewaterhouse Coopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2010 annual stockholders' meeting. In addition, the information set forth under the caption "Business-Other Business Matters-Corporate Governance Matters" in Item 1 regarding our Code of Business Conduct is incorporated by reference in response to this Item.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2010 annual stockholders' meeting.

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

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2010 annual stockholders' meeting.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2010 annual stockholders' meeting.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this Item is incorporated by reference to the Company's definitive Proxy Statement in connection with the 2010 annual stockholders' meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 61.

2. Financial Statement Schedules

None.

3. Exhibits

The following instruments are included as exhibits to this report. Those exhibits below incorporated by reference herein are indicated as such by the information supplied in the parenthetical thereafter. If no parenthetical appears after an exhibit, copies of the instrument have been included herewith. Our commission file number is 1-10447.

Exhibit Number	Description
3.1	Restated Certificate of Incorporation of the Company (Form 8-K for January 21, 2010).
3.2	Amended and Restated Bylaws of the Company amended January 14, 2010 (Form 8-K for January 14, 2010).
4.1	Form of Certificate of Common Stock of the Company (Registration Statement No. 33-32553).
4.2	Note Purchase Agreement dated as of July 26, 2001 among Cabot Oil & Gas Corporation and the Purchasers listed therein (Form 8-K for August 30, 2001).
4.3	Note Purchase Agreement dated as of July 16, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 8-K for July 16, 2008).
4.4	Note Purchase Agreement dated as of December 1, 2008 among Cabot Oil & Gas Corporation and the Purchasers named therein (Form 10-K for 2008).
4.5	Credit Agreement, dated as of April 24, 2009, among the Company, JPMorgan Chase Bank, N.A., as Administrative Agent, Banc of America Securities LLC, as Syndication Agent, Bank of Montreal, as Documentation Agent, and the Lenders party thereto (Form 8-K for April 24, 2009).
* 10.1	Form of Change in Control Agreement between the Company and Certain Officers (Form 10-K for 2008).
* 10.2	Form of Supplemental Executive Retirement Agreement (Form 10-K for 2008).
* 10.3	1990 Non-employee Director Stock Option Plan of the Company (Form S-8) (Registration No. 33-35478).
	(a) First Amendment to 1990 Non-employee Director Stock Option Plan (Post-Effective Amendment No. 2 to Form S-8) (Registration No. 33-35478).
	(b) Second Amendment to 1990 Non-employee Director Stock Option Plan (Form 10-K for 1995).
* 10.4	Second Amended and Restated 1994 Long-Term Incentive Plan of the Company (Form 10-K for 2001).
* 10.5	Second Amended and Restated 1994 Non-Employee Director Stock Option Plan (Form 10-K for 2001).
* 10.6	Form of Indemnity Agreement between the Company and Certain Officers (Form 10-K for 1997).
* 10.7	Deferred Compensation Plan of the Company, as Amended and Restated, Effective January 1, 2009 (Form 10-K for 2008).
10.8	Trust Agreement dated September 2000 between Harris Trust and Savings Bank and the Company (Form 10-K for 2001).
10.9	Lease Agreement between the Company and DNA COG, Ltd. dated April 24, 1998 (Form 10-K for 1998).
*10.10	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001).
	(a) Amendment to Employment Agreement between the Company and Dan O. Dinges, effective December 31, 2008 (Form 10-K for 2008).
*10.11	2004 Incentive Plan (Form 10-Q for the quarter ended June 30, 2004).
	(a) First Amendment to the 2004 Incentive Plan effective February 23, 2007 (Form 10-Q for the quarter ended March 31, 2007).
	(b) Second Amendment to the 2004 Incentive Plan Amendment, effective as of January 1, 2009 (Form 10-K for 2008).
*10.12	2004 Performance Award Agreement (Form 10-Q for the quarter ended June 30, 2004).
*10.13	2004 Annual Target Cash Incentive Plan Measurement Criteria for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.14	Form of Restricted Stock Awards Terms and Conditions for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
*10.15	2005 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 8-K for May 24, 2005).
*10.16	Savings Investment Plan of the Company, as amended and restated effective January 1, 2001 (Form 10-K for 2005).

Exhibit Number	Description
	(a) First Amendment to the Savings Investment Plan effective January 1, 2002 (Form 10-K for 2005).
	(b) Second Amendment to the Savings Investment Plan effective January 1, 2003 (Form 10-K for 2005).
	(c) Third Amendment to the Savings Investment Plan effective January 1, 2005 (Form 10-K for 2005).
*10.17	Forms of Award Agreements for Executive Officers under 2004 Incentive Plan (Form 10-K for 2006).
	(a) Form of Restricted Stock Award Agreement (Form 10-K for 2006).
	(b) Form of Stock Appreciation Rights Award Agreement (Form 10-K for 2006).
	(c) Form of Performance Share Award Agreement (Form 10-K for 2006).
10.18	Cabot Oil & Gas Corporation Mineral, Royalty and Overriding Royalty Interest Plan (Registration Statement No. 333-135365).
	(a) Form of Conveyance of Mineral and/or Royalty Interest (Registration Statement No. 333-135365).
	(b) Form of Conveyance of Overriding Royalty Interest (Registration Statement No. 333-135365).
10.19	Purchase and Sale Agreement dated August 25, 2006 between Cabot Oil & Gas Corporation, a Delaware corporation, Cody Energy LLC, a Colorado limited liability company, and Phoenix Exploration Company LP, a Delaware limited partnership (Form 8-K for September 29, 2006).
*10.20	Form of Amendment of Employee Award Agreements (Form 8-K for December 19, 2006).
*10.21	Savings Investment Plan of the Company, as amended and restated effective January 1, 2006 (Form 10-K for 2006).
	(a) First Amendment to the Savings Investment Plan of the Company effective January 1, 2006 (Form 10-K for 2007).
	(b) Second Amendment to the Savings Investment Plan of the Company effective April 23, 2008 (Form 10-Q for the quarter ended March 31, 2008).
	(c) Third Amendment to the Savings Investment Plan of the Company effective July 1, 2008 (Form 10-K for 2008).
	(d) Fourth Amendment to the Savings Investment Plan of the Company effective January 1, 2008 (Form 10-K for 2008).
*10.22	Pension Plan of the Company, as amended and restated effective January 1, 2006 (Form 10-K for 2006).
	(a) First Amendment to the Pension Plan of the Company effective January 1, 2006 (Form 10-K for 2007).
	(b) Second Amendment to the Pension Plan of the Company effective April 23, 2008 (Form 10-Q for the quarter ended March 31, 2008).
	(c) Third Amendment to the Pension Plan of the Company effective July 1, 2008 (Form 10-K for 2008).
	(d) Fourth Amendment to the Pension Plan of the Company effective January 1, 2008 (Form 10-K for 2008).
	(e) Fifth Amendment to the Pension Plan of the Company effective January 1, 2010.
10.23	Purchase and Sale Agreement dated June 3, 2008 by and among Enduring Resources, LLC, Mustang Drilling, Inc., Minden Gathering Services, LLC and Cabot Oil & Gas Corporation (Form 10-Q for the quarter ended June 30, 2008).
*10.24	Savings Investment Plan of the Company, as amended and restated effective January 1, 2010.
14.1	Amendment of Code of Business Conduct (as amended on July 28, 2005 to revise Section III. F. relating to Transactions in Securities and Article V. relating to Safety, Health and the Environment) (Form 10-Q for the quarter ended June 30, 2005).
21.1	Subsidiaries of Cabot Oil & Gas Corporation.
23.1	Consent of PricewaterhouseCoopers LLP.
23.2	Consent of Miller and Lents, Ltd.
31.1	302 Certification – Chairman, President and Chief Executive Officer.
31.2	302 Certification – Vice President and Chief Financial Officer.
32.1	906 Certification.
99.1	Miller and Lents, Ltd. Review Letter.
**101.INS	XBRL Instance Document.
**101.SCH	XBRL Taxonomy Extension Schema Document.
**101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
**101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
**101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.
**101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.

* Compensatory plan, contract or arrangement.

**Furnished, not filed. Users of this data submitted electronically herewith are advised pursuant to Rule 406T of Regulation S-T that this interactive data file is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act of 1933, is deemed not filed for purposes of section 18 of the Securities Exchange Act of 1934, and otherwise is not subject to liability under these sections.

SIGNATURES

Pursuant to the requirements of Section 13 and 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, in the City of Houston, State of Texas, on the 26th of February 2010.

CABOT OIL & GAS CORPORATION

By: /s/ Dan O. Dinges
Dan O. Dinges
Chairman, President and Chief Executive Officer

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/ Dan O. Dinges Dan O. Dinges	Chairman, President and Chief Executive Officer (Principal Executive Officer)	February 26, 2010
/s/ Scott C. Schroeder Scott C. Schroeder	Vice President and Chief Financial Officer (Principal Financial Officer)	February 26, 2010
/s/ Henry C. Smyth Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	February 26, 2010
/s/ Rhys J. Best Rhys J. Best	Director	February 26, 2010
/s/ David M. Carmichael David M. Carmichael	Director	February 26, 2010
/s/ Robert L. Keiser Robert L. Keiser	Director	February 26, 2010
/s/ Robert Kelley Robert Kelley	Director	February 26, 2010
/s/ P. Dexter Peacock P. Dexter Peacock	Director	February 26, 2010
/s/ William P. Vititoe William P. Vititoe	Director	February 26, 2010

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