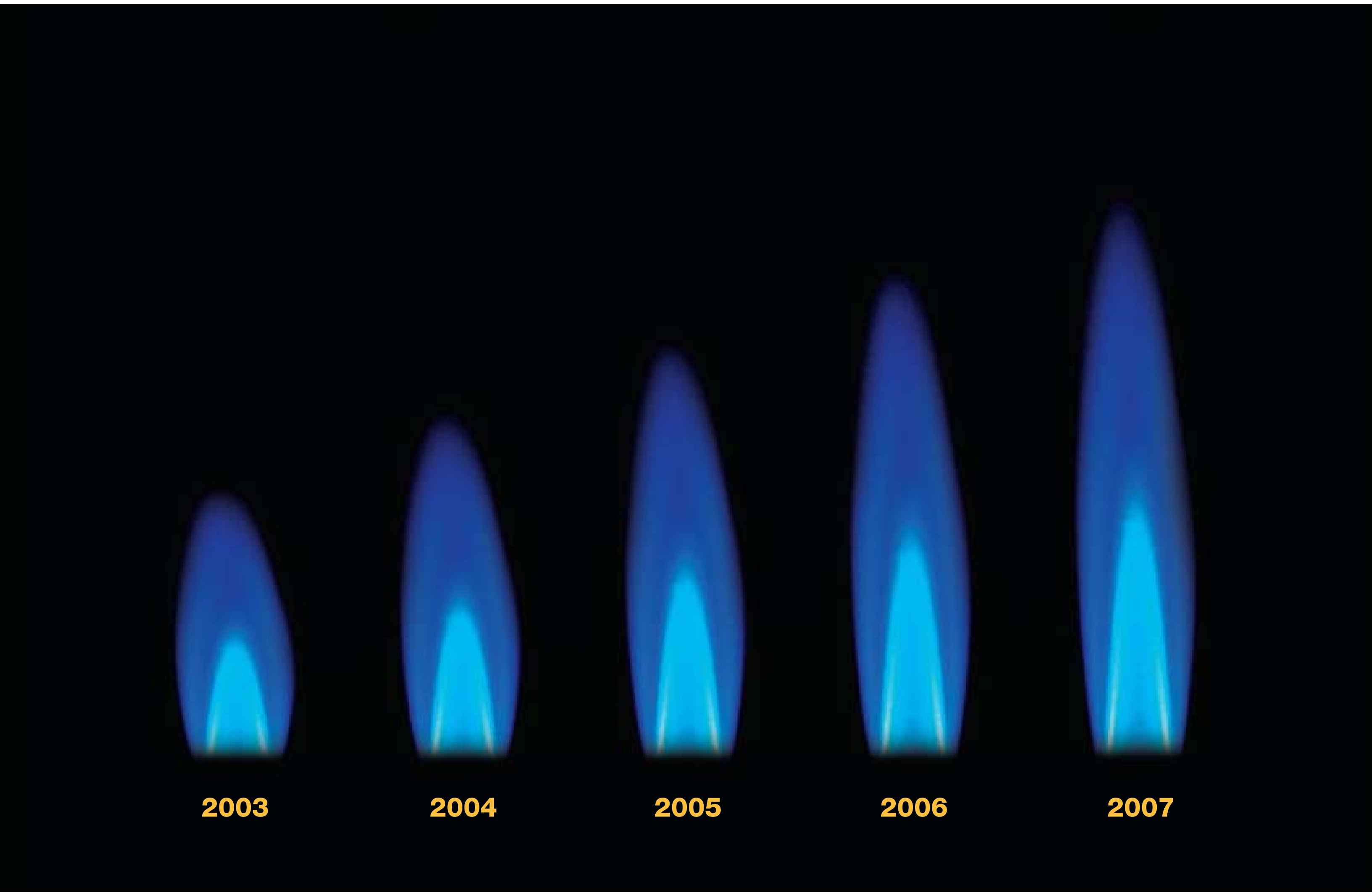
Cabot Oil & Gas Corporation



measures of SUCCESS

2007 Annual Report

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. The five principal areas of operation are the Appalachian Basin, the Gulf Coast, including south and east Texas and north Louisiana, the Rocky Mountains, the Anadarko Basin and the deep gas basin of Western Canada. Operationally, the four regional offices are located in Houston, Texas; Charleston, West Virginia; Denver, Colorado; and Calgary, Alberta.

"Measures of Success"
Cabot focuses on economic growth in both reserves and production, year after year, that translates into value creation.

Financial **Highlights**

	Year Ended December 31, 2005	2006	**2007**
Financial Data *(In millions, except share amounts)*			
Operating Revenues	$ 682.8	$ 762.0	**$ 732.2**
Net Income	$ 148.4	$ 321.2	**$ 167.4**
Per Share (1)	$ 1.52	$ 3.32	**$ 1.73**
Discretionary Cash Flow (2)	$ 374.4	$ 355.8	**$ 472.7**
Per Share (1)	$ 3.83	$ 3.68	**$ 4.87**
Capital and Exploration Expenditures	$ 425.6	$ 537.5	**$ 636.2**
Common Dividends per Share (1)	$ 0.07	$ 0.08	**$ 0.11**
Average Common Shares Outstanding *(In thousands)* (1)	97,713	96,803	**96,978**
Capitalization *(In millions)*			
Long-Term Debt	$ 320.0	$ 220.0	**$ 330.0**
Stockholders' Equity *(Successful Efforts Method)*	$ 600.2	$ 945.2	**$ 1,070.3**
Annual Production Volume			
Absolute *(Bcfe)*	84.4	88.2	**85.5**
Pro Forma *(Bcfe)* (4)	64.1	74.9	**85.5**
Pro Forma % Growth	6%	17%	**14%**
% Gas	88%	90%	**94%**
Proved Reserves (3)			
Natural Gas *(Bcf)*	1,262.1	1,368.3	**1,560.0**
Oil, Condensate and Natural Gas Liquids *(Mmbbl)*	11.5	8.0	**9.3**
Total Proved *(Bcfe)*	1,330.9	1,416.1	**1,615.9**
Total Developed *(Bcfe)*	999.7	1,032.2	**1,176.1**
% Gas	95%	97%	**97%**
% Developed	75%	73%	**73%**
Reserve Life Index *(Years)*	15.8	16.1	**18.9**
Reserve Additions			
Drilling Additions *(Bcfe)*	187.9	252.6	**274.1**
Drilling Additions, Revisions and Purchases *(Bcfe)*	212.9	241.1	**285.2**
Reserve Replacement %	252%	273%	**334%**
Reserve Replacement Costs – Additions *($ per Mcfe)*	$ 1.77	$ 1.97	**$ 2.14**
Reserve Replacement Costs – Additions, Revisions and Purchases *($ per Mcfe)*	$ 1.91	$ 2.10	**$ 2.07**
Wells Drilled			
Total Gross	316	387	**461**
Total Net	247.1	307.0	**390.9**
Gross Success Rate %	95%	96%	**96%**
Produced Average Natural Gas Sales Price *($ per Mcf)*			
East	$ 8.02	$ 7.99	**$ 7.78**
Gulf Coast	$ 6.38	$ 7.37	**$ 8.03**
West	$ 6.00	$ 6.05	**$ 6.13**
Canada	$ 6.79	$ 6.18	**$ 5.47**
Total Company	$ 6.74	$ 7.13	**$ 7.23**
Produced Average Crude and Condensate Sales Price *($ per Bbl)*	$ 44.19	$ 65.03	**$ 67.16**

(1) Prior years have been adjusted to reflect a 2-for-1 stock split in 2007.

(2) Net income plus non-cash items from operations and exploration expenses.

(3) Changes in reserves from year to year reflect drilling additions and revisions as well as reserves purchased and sold. *See page 103 of this report for details.*

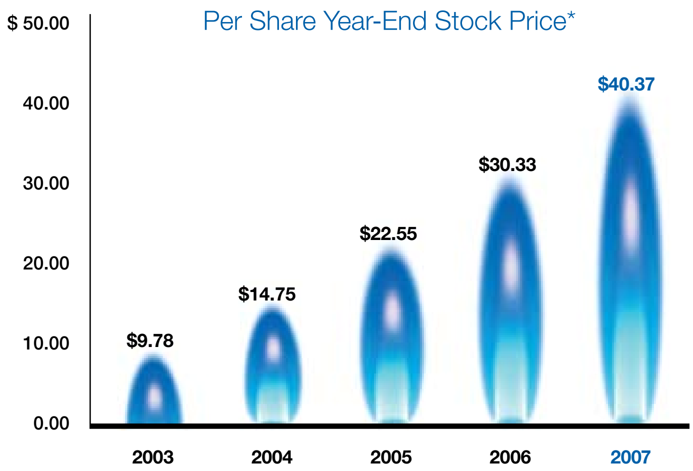
(4) Excludes production sold in the 2006 south Louisiana and offshore properties sale.

To Our **Shareholders:**

Our goal as an exploration and production company is to consistently deliver double digit growth in reserves and production, in an efficient manner, year after year. That is exactly how we measure success!

I am pleased to report that for 2007 we delivered on that expectation from all aspects, while generating record levels of cash flow and our second best earnings report. These statistics point to another successful year both operationally and financially that had the impact of increasing our shareholder value by 33 percent between year-end 2006 and year-end 2007. The Company also experienced another stock split and dividend increase, the second in two years. Our specific accomplishments included:

- Reserve replacement of 334 percent from the Company's 96 percent successful drilling program. Our year-end reserves were 1,616 Bcfe versus 1,416 Bcfe in 2006, or a 14 percent increase. We believe we have a competitive advantage with the nature of our resources and our ability to efficiently add reserves each year from our low risk inventory of opportunities.



* Split Adjusted

- In terms of production, the Company grew on a comparable basis by 14 percent year over year. We had total production of 85.5 Bcfe in 2007, which compared to 74.9 Bcfe in 2006 after the removal of nine months of production related to the sold properties.
- Finding cost was lower compared to the previous year, in spite of inflation in the service sector. We reported an all-in cost of $2.07 per Mcfe, with effective allocation of our largest capital program ever. This metric was accomplished with our proved undeveloped reserves percentage of 27 percent remaining unchanged.
- We continued development activity across our regions and matured two new plays (County Line and Marcellus shale), which will be significant parts of the 2008 program and future year programs.
- Net income for 2007 totaled $167.4 million, or $1.73 per share which was second only to the 2006 levels.
- The Company established new highs for its cash flow metrics recording $462.1 million for cash flow from operations and $472.7 for discretionary cash flow.
- Because of the robust level of cash flow, we were able to maintain a debt to total capitalization ratio of below 25 percent, a nice accomplishment considering our largest capital investment level ever. Financial flexibility is an important attribute in the uncertain world of financial markets in which we live, and the fiscal demands of the resource plays that form the nucleus of our drilling programs.

With a strong balance sheet, an extensive inventory of projects (many in the hottest plays in the industry right now), excellent commodity prices and increasing interest in the Company, Cabot is entering 2008 stronger and more focused than ever before.

Looking Ahead

For 2008, we will focus over 80 percent of our $490 million investment program in the East region and in our East Texas basin. The allocation of capital in these two expanding areas provides the shareholder a significant return on each dollar invested and allows for continued future growth. We have a significant acreage position in both areas. The plan is to exploit our acreage by drilling a number of wells in four core projects – County Line, Trawick, Huron shale, Marcellus shale – along with our traditional drilling throughout our regions. A more detailed discussion of each of these core projects is provided later in this report.

Our original program is targeted around the level of expected cash flow (using an average $7.00 per Mcf index price) for the year, which leaves plenty of flexibility to expand our efforts when the opportunity presents itself. Traditionally, to achieve the most efficient use of capital we start the year with a smaller program and expand as opportunities develop. For 2008, we have hedged approximately 50% of the anticipated production level to underpin program execution and mitigate commodity price volatility. We generally utilize collar arrangements to allow participation in the upside in the commodity cycles. The average floor and fixed price is $8.19 per Mcf (average floor price is $8.28 per Mcf).

Our investment program has increased five-fold from the level when I became CEO of the Company in 2002. Following a redeployment of our intellectual skill set, which resulted in only a small net increase in personnel, Cabot established the depth, strength and talent in its personnel for future challenges.

Cabot's Board and senior management are very cognizant of the value of skilled employees and the challenges to attract and retain key personnel. Because of this, our growth plans and our collective desire to build value, we took a unique position and incentivized every non-officer employee to work diligently to create value aligned with shareholder objectives. This value is measured by first achieving a $50 per share stock price and then a $60 per share stock price by executing our plans during the next two and four year periods, respectively. Right now every single employee is aligned with you and if we meet the higher price target (a $2 billion increase in Company value will have occurred) and all non-officer employees will share $45 million. This incentive yields a handsome payoff for both employee and shareholder alike.

From a shareholder's perspective, I receive a great deal of comfort knowing behind every Cabot share there lies a very talented, dedicated employee skill set, a strong balance sheet, significant proven assets, a deep portfolio of low risk opportunities, an organic ability to grow production and reserves each year, efficiency in the program to delivery strong rates of return that enable us to add reserves at a top tier finding cost, not to mention the Company's exposure to a couple of the most exciting new plays in the industry today.

I would like to take this opportunity to thank Jim Floyd for his years of service and counsel as a valued member of Cabot's Board. Jim retired from the Board at the end of 2007 and his depth of industry knowledge and candor will be missed.

In closing, I do appreciate the Board's support of our strategy and the shareholders' commitment to the growth profile of our Company. With Cabot's committed workforce and portfolio of opportunities we have established, I look forward to a very successful 2008 and continued success for years to come.

Sincerely,

Dan O. Dinges

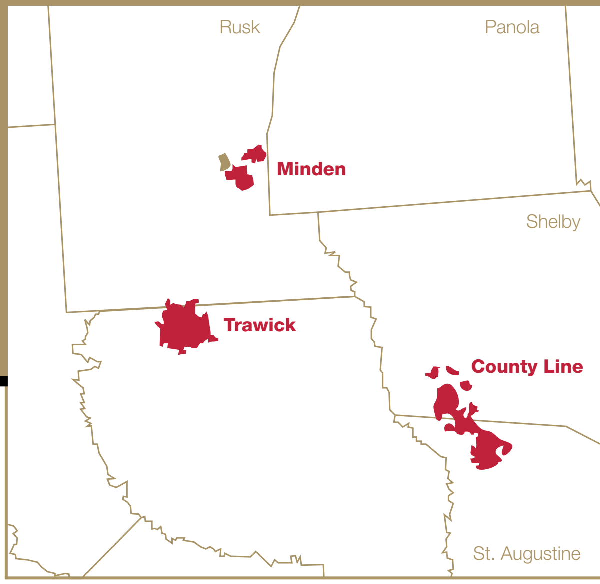
Dan O. Dinges
Chairman, President and Chief Executive Officer

proved RESERVES 1,616 Bcfe,

a new high and growing!


HALLIBURTO

East **Texas**



The focus of the Company's 2008 program for the Gulf Coast region is in East Texas. The two main areas include County Line and Trawick, where the Company has acquired or gained access to 62,000 gross acres, along with additional efforts in the Minden field. The proximity of these fields is highlighted on the map.

County Line

Presently a key project in the Company, this area has become a premier development project. Prospective in both the James Lime and Pettet formations, this 26,000 acre prospective area has moved from no measurable production at the end of 2006 to about 40 Mmcf per day in the first quarter of 2008.

This production ramp has been driven by 100 percent success in a 16 well horizontal drilling program targeting the James Lime. With this success came the need for pipeline expansion that now allows for take-away capacity in excess of 100 Mmcf per day. This gives Cabot ample room for growth and with further infrastructure investments, capacity can move even higher.

Because of the field's contribution to the Company and its ultimate potential, Cabot will initially have two rigs increasing to three rigs drilling its 2008 program. This effort will include at least 32 James Lime horizontal wells, and focus on the southern portion of the acreage, where Cabot has a high degree of confidence in this area.

With the effort to date, the Company believes it has "proven" a 12-mile swath of acreage that would include 100 to 110 future drilling locations and still have another 70 to 100 potential locations on the north end of the acreage, all in the James Lime. Of this, only eight locations were included in the year-end reserves.

County Line is a James Lime horizontal effort at this time. The field also has the Pettet formation slightly deeper, which has been proven and in the future will become a contributor to the Company's reserve and production profiles.

Trawick

In September of 2007, Cabot announced an agreement whereby it gained access to 36,000 acres from a "major" oil company. In the same fairway as the County Line field, this area exposes the Company to opportunities in several known productive formations (See Figure 1), including the under-exploited Cotton Valley and Haynesville, creating the excitement for Cabot.

Figure 1. Trawick Field

Depth	Formation	Wells	Cumulative Production *(Bcfe)*
7,500′	James	90	165
7,700′	Pettet	68	616
8,000′	Travis Peak	149	430
10,000′	Cotton Valley	2	0.8
12,600′	Haynesville	2	4.5

Per the terms of the agreement, the Company is required to drill eight wells to earn further drilling rights, but it plans to drill a minimum of 12 wells in 2008. Additionally in this area, Cabot is exploiting the Travis Peak with six successful wells recently drilled on exploration acreage outside of the Trawick area, which has effectively confirmed the Company's thesis of prospectivity throughout this East Texas area.

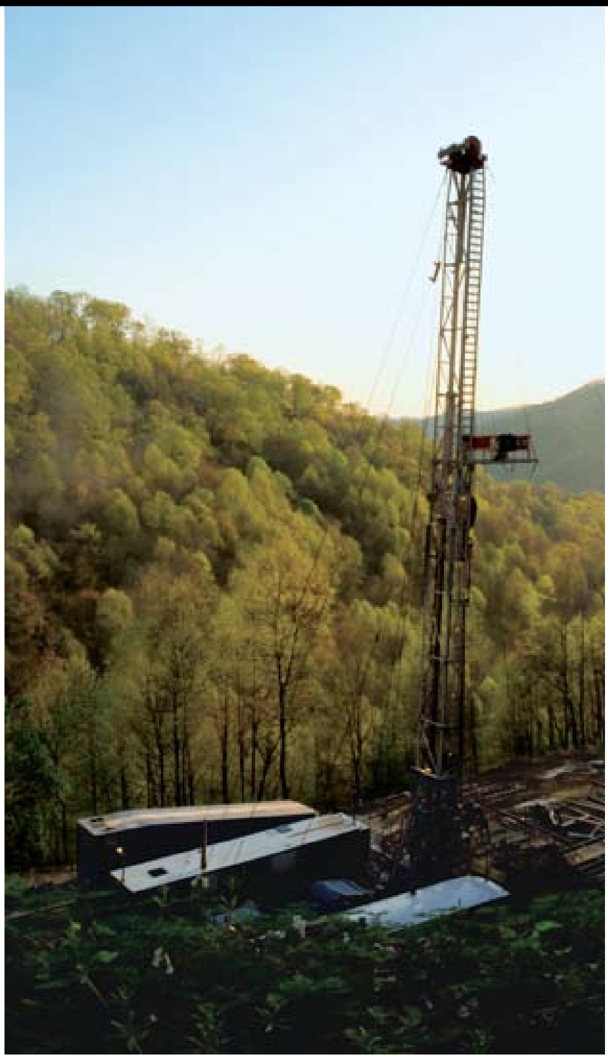
For 2008, Cabot's effort will focus on drilling the deep Haynesville and Cotton Valley formations within the Trawick area, along with exploiting the Travis Peak formation on the exploration acreage. Early indications have shown production success in both the deep Haynesville and Cotton Valley formations. Cabot is in the very early stage of exploitation here, but indications so far show opportunities for years to come.

Minden

This area was one of the Company's initial projects in East Texas. Since the drilling of the first well in 2005, 78 additional wells have been completed with 100% success. The Minden field has been an area of consistent reserve additions and a dependable contributor to Cabot's profile.

With the evolution of several new projects as discussed above and the fact that all of the Minden acreage is now held by production, the Company will initially reallocate capital to the newer areas in 2008 and plan an expanded drilling program in the Minden area for 2009.

East **Region**



The Company's legacy assets are once again revitalized, this time by an industry-wide movement to exploit the Marcellus shale.

Marcellus

In 2007, many producers (both existing Appalachia and non-Appalachia participants) went in search of a position in this major shale gas play. The Marcellus long present, but lightly exploited, is now mentioned along with the Barnett shale. Cabot reacted opportunistically and began adding to its already extensive shale holdings in 2006 and now the Company holds over 100,000 new acres in Pennsylvania to go with over 200,000 plus, identified prospective existing acres in West Virginia, where Cabot's infrastructure already exists.

In one project area, the Company is in full scale development with 20 wells planned for 2008 in Pennsylvania (both vertical and horizontal). In addition, pipeline infrastructure is being planned with production anticipated here later in 2008.

In another project, Cabot's traditional vertical well development program has been augmented to deepen 68 of these traditional wells to the Marcellus. During 2008, this traditional area will also see at least two horizontal Marcellus tests. In both projects, horizontal success could significantly change the drilling effort in 2008 and into the future.

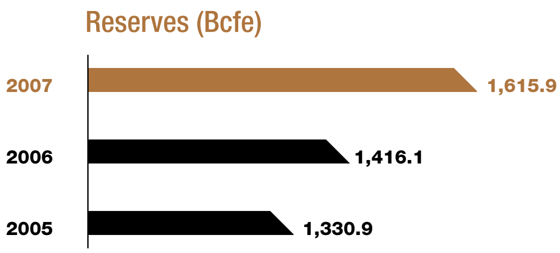
The Marcellus, like Trawick in East Texas, is in the early stages of exploitation, but appears to have the characteristics to add significant value for Cabot shareholders.

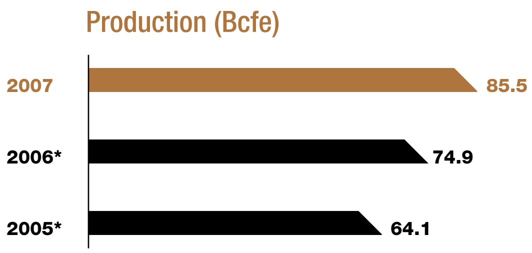
Hurricane

Cabot's horizontal Huron shale program will resume and expand in 2008 to about 19 wells after a short delay waiting on infrastructure enhancements to deal with the nitrogen introduced into the formation during the stimulation process. The blending process will begin shortly, which will allow the Company to flow these wells at full rate. Cabot believes these wells, based on early information, should ultimately produce about 1 Bcfe per well with a total completed cost of about $1.0 million.

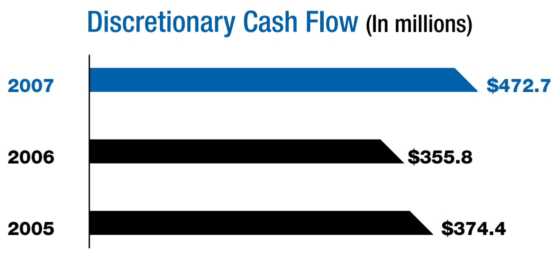
The 2008 program will provide the needed additional data points for the Company's horizontal effort both here and throughout West Virginia and Pennsylvania.

three-year (all-in)
FINDING COSTS
$2.03 per Mcfe


Reserves (Bcfe)
2007
1,615.9
2006
1,416.1
2005
1,330.9


Production (Bcfe)
2007
85.5
2006*
74.9
2005*
64.1

* Pro Forma



Other Data **Points**

- The 2008 Chester-Morrow effort in the Mid-Continent makes up 11 percent of the 2008 capital program. As a result of the excellent returns, which are some of the best in the Company, the program has been increasing year after year. Next year, 66 wells are planned.
- Cabot's 2008 Rocky Mountain program stands at 16 wells (including seven Moxa Arch obligatory wells), a conservative effort based on the poor Rocky Mountain gas prices experienced in late 2007. With

the strengthening prices and the apparent positive effects from the newly completed Phase I and II of the Rockies Express Pipeline (REX), the Company is reviewing an expanded program in the Moxa Arch area. Cabot's 2008 hedging program, which includes hedges covering approximately 55% in volumes related to the Rocky Mountains, will be key to expanding the program.

- Due to uncertainties related to the Alberta royalty changes and the unfavorable exchange rate, the Company chose to limit its capital exposure in Canada until these issues are resolved. That being said, the plan is to undertake a modest program focused on development at Hinton and Musreau. Hinton continues to yield excellent drilling results with the successful recompletion of the Cabot RSX Hinton 9-20 at 7.4 Mmcf per day and the completion of the Cabot RSX Hinton 14-20 flowing at 6.7 Mmcf per day. Cabot plans to continue drilling at Hinton during the early part of 2008.

Board of **Directors**

Directors

Dan O. Dinges
Chairman, President and Chief Executive Officer

John G. L. Cabot
Former Vice Chairman of the Board and Chief Financial Officer, Cabot Corporation

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
John G. L. Cabot – *Chairman*
Robert L. Keiser
Robert Kelley
P. Dexter Peacock

Compensation Committee
William P. Vititoe – *Chairman*
David M. Carmichael
Robert Kelley

Executive Committee
P. Dexter Peacock – *Chairman*
John G. L. Cabot
Dan O. Dinges

Corporate Governance and Nominations Committee
Robert Kelley – *Chairman*
David M. Carmichael
P. Dexter Peacock
William P. Vititoe

Safety and Environmental Affairs Committee
Robert L. Keiser – *Chairman*
John G. L. Cabot

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, 2007**
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)

1200 Enclave Parkway, Houston, Texas 77077
(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**
Rights to Purchase Preferred Stock	**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 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 [X].

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 29, 2007) was approximately $3.6 billion.

As of February 25, 2008, there were 97,768,036 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held April 30, 2008 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, 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. Our five principal areas of operation are the Appalachian Basin, onshore Gulf Coast, including south and east Texas and north Louisiana, the Rocky Mountains, the Anadarko Basin and the deep gas basin of Western Canada. Operationally, we have four regional offices located in Houston, Texas; Charleston, West Virginia; Denver, Colorado; and Calgary, Alberta.

Net income for 2007 of $167.4 million, or $1.73 per share, was lower than the prior year's net income of $321.2 million, or $3.32 per share, by $153.8 million, or 48%. The year-over-year net income decrease was primarily due to the recognition of a gain on sale of assets of $231.2 million ($144.5 million, net of tax) in 2006 related to the disposition of our offshore portfolio and certain south Louisiana properties to a third party, which was substantially completed in 2006 (the 2006 south Louisiana and offshore properties sale) and, to a lesser extent, lower operating revenues as discussed below. Additionally, operating expenses increased by $5.8 million between 2006 and 2007 principally due to increased depreciation, depletion and amortization costs and impairment charges, partially offset by lower exploration and general and administrative expenses. These lower operating revenues and increased operating expenses, along with a $1.2 million decrease in interest and other expense, reduced income before income taxes by $253.0 million and consequently decreased income tax expense by $99.2 million. Also contributing to the decrease in income taxes was the decrease in the effective tax rate primarily due to a reduction in our overall state income tax liability for 2007 relating to the 2006 south Louisiana and offshore properties sale.

Operating revenues decreased by $29.8 million, or four percent, over the prior year as described below. Natural gas production revenues increased by $13.5 million, or two percent, over the prior year due to an increase in realized natural gas prices and an increase in natural gas production in the West region, East region and Canada, partially offset by decreased natural gas production in the Gulf Coast region as a result of the 2006 south Louisiana and offshore properties sale. Crude oil and condensate revenues decreased by $36.2 million, or 40%, over the prior year mainly due to decreased crude oil and condensate production in the Gulf Coast region as a result of the 2006 south Louisiana and offshore properties sale, partially offset by an increase in crude oil realized prices. Excluding $70.5 million and $47.4 million, respectively, of natural gas and crude oil revenues from our 2006 results that were attributable to the 2006 south Louisiana and offshore properties sale, natural gas revenues for 2007 would have increased by 17% and crude oil revenues would have increased by 26%. Brokered natural gas revenues decreased by $0.5 million due to a decrease in brokered volumes, offset in part by an increase in sales price.

In 2007, energy commodity prices remained strong throughout the year. Our 2007 average realized natural gas price was $7.23 per Mcf, one percent higher than the 2006 average realized price of $7.13. Our 2007 average realized crude oil price was $67.16 per Bbl, three percent higher than the 2006 average realized price of $65.03. 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. Our balance sheet, strengthened by the 2006 south Louisiana and offshore properties sale, and a hedge position covering approximately half of our anticipated production at levels exceeding our budgeted prices, allowed us to once again expand our capital program. In 2007, we pursued and completed the largest investment program in our history ($636.2 million) which was funded largely through cash flow from operations and, to a lesser extent, borrowings on our revolving credit facility. We believe our balance sheet and availability under our credit facility provides sufficient liquidity to pursue our 2008 program and evaluate other opportunities.

On an equivalent basis, our production level in 2007 decreased by three percent from 2006. We produced 85.5 Bcfe, or 234.1 Mmcfe per day, in 2007, as compared to 88.2 Bcfe, or 241.7 Mmcfe per day, in 2006. Natural gas production increased to 80.5 Bcf in 2007 from 79.7 Bcf in 2006 primarily due to increased production in the West and East regions associated with an increase in the drilling program and an increase in Canada due to increased pipeline capacity and drilling activity in the Hinton field, partially offset by a decline in Gulf Coast production. Excluding 9.0 Bcf of natural gas production sold in the 2006 south Louisiana and offshore properties sale, total natural gas production would have increased by 14%. Gulf Coast natural gas production decreased from 29.9 Bcf in 2006 to 26.8 Bcf in 2007 primarily due to the 2006 south Louisiana and offshore properties sale. Excluding 9.0 Bcf of production sold in that sale, Gulf Coast production would have increased 28% in 2007 over 2006, primarily due to increased drilling in the Minden, Angie (County Line) and McCampbell fields and recompletions in the Raymondville field. Oil production decreased by 582 Mbbls from 1,405 Mbbls in 2006 to 823 Mbbls in 2007, due primarily to a decrease in production in the Gulf Coast region. Excluding 707 Mbbls of crude oil production related to the 2006 south Louisiana and offshore properties sale, oil production would have increased by 18% from 2006 to 2007 mainly due to an increase in drilling and workover activity in the McCampbell field and, to a lesser extent, in the Minden field. Oil production increased slightly in the East region and in Canada and decreased by 17% in the West region due to natural decline. Excluding 13.3 Bcfe of equivalent production sold in the 2006 south Louisiana and offshore properties sale, total equivalent production would have increased by 10.6 Bcfe, or 14%.

A portion of our production was covered by oil and gas hedge instruments throughout 2006 and 2007. Again during 2007 as in 2006, we employed the use of collars to hedge our price exposure on our production. In addition, at the end of 2007, we employed the use of cash flow swaps to cover a portion of our 2008 natural gas production. For 2007, collars covered 53% of natural gas production and had a weighted-average floor of $8.99 per Mcf and a weighted-average ceiling of $12.19 per Mcf. At December 31, 2007, approximately 38% of the anticipated 2008 natural gas production is hedged using collars with a weighted-average floor of $8.17 per Mcf and a weighted-average ceiling of $10.14 per Mcf. Swaps as of December 31, 2007 cover approximately six percent of our anticipated 2008 natural gas production with a weighted-average price of $7.44 per Mcf. For 2007, collars covered 44% of crude oil production with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl. At December 31, 2007, approximately 49% of our anticipated crude oil production is hedged for 2008 with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl. As of December 31, 2007, no derivatives are in place for 2009. Our decision to hedge 2008 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.

For the year ended December 31, 2007, we drilled 461 gross wells (391 net) with a success rate of 96% compared to 387 gross wells (307 net) with a success rate of 96% for the prior year. In 2008, we plan to drill approximately 419 gross wells (366 net). The number of wells we plan to drill in 2008 is down from 2007 primarily due to lower planned activity in the Rocky Mountains area based on lower natural gas prices and lower planned activity in Canada based on uncertainty around royalties and exchange rates. Our 2007 capital and exploration spending was $636.2 million compared to $537.5 million of total capital and exploration spending in 2006. In both 2007 and 2006, 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 2008. Funding of the program is expected to be provided by operating cash flow, existing cash and increased borrowings, if required. We remain focused on our strategies of pursuing lower risk drilling opportunities that provide more predictable results and selectively pursuing impact exploration opportunities as we accelerate drilling on our accumulated acreage position. For 2008, the Gulf Coast region will start the year with the largest allocation of capital, followed by the East, the West and Canada. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long term. In 2008, we plan to spend approximately $490 million on capital and exploration activities.

Our proved reserves totaled approximately 1,616 Bcfe at December 31, 2007, of which 97% was natural gas. This reserve level was up by 14 percent from 1,416 Bcfe at December 31, 2006 on the strength of results from our drilling program and the increase in our capital spending.

The following table presents certain reserve, production and well information as of December 31, 2007.

	East	Gulf Coast	West: Rocky Mountains	West: Mid-Continent	West: Total	Canada	**Total**
Proved Reserves at Year End *(Bcfe)*							
Developed	551.2	207.9	206.6	177.8	384.4	32.6	**1,176.1**
Undeveloped	227.2	116.3	65.0	28.1	93.1	3.2	**439.8**
Total	**778.4**	**324.2**	**271.6**	**205.9**	**477.5**	**35.8**	**1,615.9**
Average Daily Production *(Mmcfe per day)*	67.1	83.4	41.4	31.2	72.6	11.0	**234.1**
Reserve Life Index *(In years)* (1)	31.8	10.7	18.0	18.1	18.0	8.9	**18.9**
Gross Wells	3,178	685	677	778	1,455	38	**5,356**
Net Wells (2)	2,962.2	464.1	302.0	541.8	843.8	13.4	**4,283.5**
Percent Wells Operated *(Gross)*	97.1%	73.3%	50.2%	77.8%	64.9%	55.3%	**85.0%**

(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.

On September 29, 2006, we substantially completed the sale of our offshore portfolio and certain south Louisiana properties to Phoenix Exploration Company LP (Phoenix) for a gross sales price of $340.0 million. We 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 in 2006, we recorded a net gain of $12.3 million ($7.7 million, net of tax) in the Consolidated Statement of Operations in 2007, which included cash proceeds of $5.8 million received in the first quarter of 2007, $2.1 million in purchase price adjustments and $4.4 million that had been deferred until legal title to certain properties could be assigned.

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 seven 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 ten largest fields, which are fields with 2.5% or greater of total company proved reserves, make up approximately 48% of total company proved reserves.

EAST REGION

Our East region activities are concentrated primarily in West Virginia. This region is managed from our office in Charleston, West Virginia. 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 2007 were $178.6 million, or 28% of our total 2007 capital and exploration expenditures, compared to $145.4 million for 2006, or 27% of our total 2006 capital and exploration expenditures. Of the total company year-over-year increase in capital and exploration expenditures, 23% was attributable to an increase in the East region spending. For 2008, we have budgeted approximately $189 million for capital and exploration expenditures in the region.

At December 31, 2007, we had 3,178 wells (2,962.2 net), of which 3,085 wells are operated by us. There are multiple producing intervals that include the Big Lime, Weir, Berea and Devonian Shale formations at depths primarily ranging from 1,000 to 9,500 feet, with an average depth of approximately 4,000 feet. Average net daily production in 2007 was 67.1 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 24.4 Bcf and 26 Mbbls, respectively.

While natural gas production volumes from East reservoirs are relatively low on a per-well basis compared to other areas of the United States, the productive life of East region reserves is relatively long. At December 31, 2007, we had 778.4 Bcfe of proved reserves (substantially all natural gas) in the East region, constituting 48% of our total proved reserves. Developed and undeveloped reserves made up 551.2 Bcfe and 227.2 Bcfe of the total proved reserves for the East region, respectively. While no properties are individually significant to our company as a whole, the Sissonville, Pineville, Logan-Holden-Dingess, Big Creek, Hernshaw-Bullcreek and Huff Creek fields in West Virginia are included in our ten largest fields and together contain approximately 29% of our total company proved equivalent reserves.

In 2007, we drilled 254 wells (244.6 net) in the East region, of which 250 wells (240.8 net) were development and extension wells. In 2008, we plan to drill approximately 265 wells (258.5 net), primarily in West Virginia, including the Sissonville, Pineville, Logan-Holden-Dingess, Big Creek, Huff Creek and Hernshaw-Bullcreek fields.

In 2007, we produced and marketed approximately 71 barrels of crude oil/condensate per day in the East 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 3,100 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2007. 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 East region. The pipeline systems and storage fields are fully integrated with our operations.

The principal markets for our East region natural gas are in the northeast 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 70% of our natural gas sales volume in the East region is sold at index-based prices under contracts with a term of one year or greater. 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 two percent of East production is sold on fixed price contracts that typically renew annually.

GULF COAST REGION

Our development, exploitation, exploration and production activities in the Gulf Coast region are primarily concentrated in east and south Texas and north Louisiana. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley and James Lime formations in north Louisiana and east Texas and the Frio, Vicksburg and Wilcox formations in south Texas at depths ranging from 2,200 to 17,700 feet, with an average depth of approximately 10,800 feet.

Capital and exploration expenditures were $291.5 million for 2007, or 46% of our total 2007 capital and exploration expenditures, compared to $234.8 million for 2006, or 44% of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $209 million for capital and exploration expenditures in the region. Our 2008 Gulf Coast drilling program will emphasize activity primarily in east Texas.

We had 685 wells (464.1 net) in the Gulf Coast region as of December 31, 2007, of which 502 wells are operated by us. Average daily production in 2007 was 83.4 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 26.8 Bcf and 606 Mbbls, respectively.

At December 31, 2007, we had 324.2 Bcfe of proved reserves (89% natural gas) in the Gulf Coast region, which represented 20% of our total proved reserves. Developed and undeveloped reserves made up 207.9 Bcfe and 116.3 Bcfe of the total proved reserves for the Gulf Coast region, respectively. While no properties are individually significant to our company as a whole, the Minden field in east Texas is included in our ten largest fields based on percentage of our total company proved equivalent reserves.

In 2007, we drilled 92 wells (71.0 net) in the Gulf Coast region, of which 87 wells (66.5 net) were development and extension wells. In 2008, we plan to drill 69 wells (51.3 net), primarily in east Texas, including the Minden, County Line and Trawick fields.

Our principal markets for Gulf Coast region natural gas are in the industrialized Gulf Coast area and the northeast United States. We sell natural gas to intrastate pipelines, natural gas processors and marketing companies. Currently, approximately 50% of our natural gas sales volumes in the Gulf Coast region are sold at index-based prices under contracts with terms of one to three years. The remaining 50% of our sales volumes are sold at index-based prices under short-term agreements. The Gulf Coast properties are connected to various processing plants in Texas and Louisiana with multiple interstate and intrastate deliveries, affording us access to multiple markets.

In 2007, we produced and marketed approximately 1,659 barrels of crude oil/condensate per day in the Gulf Coast region at market responsive prices.

WEST REGION

Our activities in the West region, which is comprised of the Rocky Mountains and Mid-Continent areas, are managed by a regional office in Denver, Colorado. At December 31, 2007, we had 477.5 Bcfe of proved reserves (96% natural gas) in the West region, constituting 30% of our total proved reserves. Developed and undeveloped reserves made up 384.4 Bcfe and 93.1 Bcfe of the total proved reserves for the West region, respectively. While no properties are individually significant to our company as a whole, the Mocane-Laverne field in Oklahoma in the Mid-Continent area and the Lincoln Road and Cow Hollow fields in Wyoming in the Rocky Mountain area are included within our ten largest fields and together contain approximately 10% of our total company proved equivalent reserves.

Our principal markets for West region natural gas are in the northwest and midwest United States. We sell natural gas to power generators, natural gas processors, local distribution companies, industrial customers and marketing companies. Currently, approximately 90% of our natural gas production in the West region is sold primarily under contracts with a term of one to three years at index-based prices. Another nine percent of the natural gas production is sold under short-term arrangements at index-based prices, and the remaining one percent is sold under certain fixed-price contracts. The West region properties are connected to the majority of the midwest and northwest interstate and intrastate pipelines, affording us access to multiple markets.

In 2007, we produced and marketed approximately 476 barrels of crude oil/condensate per day in the West region at market responsive prices.

Rocky Mountains

Activities in the Rocky Mountains are concentrated in the Green River and Washakie Basins in Wyoming and Paradox Basin in Colorado. At December 31, 2007, we had 271.6 Bcfe of proved reserves (96% natural gas) in the Rocky Mountains area, or 17% of our total proved reserves.

Capital and exploration expenditures in the Rocky Mountains were $54.7 million for 2007, or nine percent of our total 2007 capital and exploration expenditures, compared to $66.2 million for 2006, or 12% of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $23 million for capital and exploration expenditures in the area.

We had 677 wells (302.0 net) in the Rocky Mountains area as of December 31, 2007, of which 340 wells are operated by us. Principal producing intervals in the Rocky Mountains area 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 10,900 feet. Average net daily production in the Rocky Mountains during 2007 was 41.4 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 14.4 Bcf and 114 Mbbls, respectively.

In 2007, we drilled 49 wells (26.2 net) in the Rocky Mountains, of which 47 wells (25.0 net) were development wells. In 2008, we plan to drill 16 wells (6.8 net), primarily in Wyoming, including the Cow Hollow and Lincoln Road fields.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwest Kansas, Oklahoma and the panhandle of Texas. At December 31, 2007, we had 205.9 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, or 14% of our total proved reserves.

Capital and exploration expenditures were $54.5 million for 2007, or eight percent of our total 2007 capital and exploration expenditures, compared to $39.8 million for 2006, or seven percent of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $56 million for capital and exploration expenditures in the area.

As of December 31, 2007, we had 778 wells (541.8 net) in the Mid-Continent area, of which 605 wells are operated by us. Principal producing intervals in the Mid-Continent are in the Chase, Morrow and Chester formations at depths ranging from 2,200 to 17,500 feet, with an average depth of approximately 7,050 feet. Average net daily production in 2007 was 31.2 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 11.0 Bcf and 66 Mbbls, respectively.

In 2007, we drilled 56 wells (43.9 net) in the Mid-Continent, all of which were development wells. In 2008, we plan to drill 66 wells (48.0 net), primarily in Oklahoma, including the Mocane-Laverne field.

CANADA REGION

Our activities in the Canada region are managed by a regional office in Calgary, Alberta. Our Canadian exploration, development and producing activities are concentrated in the Province of Alberta. At December 31, 2007, we had 35.8 Bcfe of proved reserves (97% natural gas) in the Canada region, constituting two percent of our total proved reserves. Developed and undeveloped reserves made up 32.6 Bcfe and 3.2 Bcfe of the total proved reserves for the Canada region, respectively. No properties in the Canada region are individually significant to our company as a whole. The largest field in this region is the Hinton field in Alberta, which is not included in our ten largest fields.

Capital and exploration expenditures in Canada were $55.1 million for 2007, or nine percent of our total 2007 capital and exploration expenditures, compared to $49.0 million for 2006, or nine percent of our total 2006 capital and exploration expenditures. For 2008, we have budgeted approximately $13 million for capital and exploration expenditures in the area.

We had 38 wells (13.4 net) in the Canada region as of December 31, 2007, of which 21 wells are operated by us. Principal producing intervals in the Canada region are in the Falher, Bluesky, Cadomin, Dunvegan and the Mountain Park formations at depths ranging from 8,500 to 14,500 feet, with an average depth of approximately 10,950 feet. Average net daily production in Canada during 2007 was 11.0 Mmcfe. Natural gas and crude oil/condensate/NGL production for 2007 was 3.9 Bcf and 18 Mbbls, respectively.

In 2007, we drilled 10 wells (5.2 net) in Canada, of which 8 wells (4.0 net) were development and extension wells. In 2008, we plan to drill 3 wells (1.3 net) in various fields in Alberta.

Our principal markets for Canada natural gas are in western Alberta. We sell natural gas to gas marketers. Currently, all of our natural gas production in Canada is sold primarily under contracts with a term of one year at index-based prices. The Canadian properties are connected to the major interstate pipelines.

In 2007, we produced and marketed approximately 48 barrels of crude oil/condensate per day in the Canada 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 2007 we employed natural gas price collar and swap agreements and crude oil price collar agreements for portions of our 2007 and 2008 production to attempt to manage price risk more effectively. 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 is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas for the period is greater or less than the fixed price established for that period when the swap is put in place. In 2006 and 2005, we also employed natural gas and crude oil price collar agreements. Additionally, in 2005, we employed natural gas price swap agreements. At December 31, 2007, we have natural gas price collar and swap arrangements and crude oil price collar arrangements in place for 2008.

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, 2007.

	Natural Gas *(Mmcf)*			**Liquids** (1) *(Mbbl)*			**Total** (2) *(Mmcfe)*		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	**Total**
East	548,762	227,218	775,980	404	—	404	551,187	227,218	**778,405**
Gulf Coast	185,243	104,770	290,013	3,778	1,917	5,695	207,911	116,273	**324,184**
Rocky Mountains	196,543	63,100	259,643	1,668	317	1,985	206,548	65,000	**271,548**
Mid-Continent	171,819	27,869	199,688	1,001	41	1,042	177,825	28,118	**205,943**
Canada	31,570	3,059	34,629	175	27	202	32,620	3,219	**35,839**
Total	**1,133,937**	**426,016**	**1,559,953**	**7,026**	**2,302**	**9,328**	**1,176,091**	**439,828**	**1,615,919**

(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 1 Bbl of crude oil, condensate or natural gas liquids.

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 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. has been filed as an exhibit to this Form 10-K. Our estimates of proved reserves in the table above are consistent with those filed by us with other federal agencies. During 2007, we filed estimates of our oil and gas reserves for the year 2006 with the Department of Energy. These estimates differ by 5 percent or less from the reserve data presented. Our reserves are sensitive to natural gas and crude oil sales prices and their effect on economic producing rates. Our reserves are based on oil and gas index prices in effect on the last day of December 2007. If we had considered the impact of our hedging activities, which were in a receivable position at December 31, 2007, in our proved reserves, there would not have been any significant effect.

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.

Historical Reserves

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

	Natural Gas *(Mmcf)*	Oil & Liquids *(Mbbl)*	Total *(Mmcfe)* (1)
December 31, 2004	1,134,081	11,384	1,202,383
Revision of Prior Estimates	(1,543)	1,073	4,892
Extensions, Discoveries and Other Additions	185,884	334	187,891
Production	(73,879)	(1,747)	(84,361)
Purchases of Reserves in Place	17,567	419	20,083
Sales of Reserves in Place	(14)	—	(14)
December 31, 2005	1,262,096	11,463	1,330,874
Revision of Prior Estimates (2)	(17,675)	673	(13,640)
Extensions, Discoveries and Other Additions	246,197	1,066	252,594
Production	(79,722)	(1,415)	(88,212)
Purchases of Reserves in Place	1,946	38	2,176
Sales of Reserves in Place	(44,549)	(3,852)	(67,663)
December 31, 2006	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	**1,559,953**	**9,328**	**1,615,919**
Proved Developed Reserves			
December 31, 2004	857,834	8,652	909,747
December 31, 2005	944,897	9,127	999,661
December 31, 2006	996,850	5,895	1,032,222
December 31, 2007	**1,133,937**	**7,026**	**1,176,091**

(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 on December 31, 2006 from the price on December 31, 2005.

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,		
	2007	2006	2005
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
East	**24.4**	23.5	21.4
Gulf Coast	**26.8**	30.0	28.1
West	**25.4**	23.6	23.2
Canada	**3.9**	2.6	1.2
Crude/Condensate/Ngl *(Mbbl)*			
East	**26**	24	27
Gulf Coast	**606**	1,164	1,530
West	**180**	214	172
Canada	**18**	13	18
Produced Natural Gas Sales Price *($/Mcf)* (1)			
East	**$ 7.78**	$ 7.99	$ 8.02
Gulf Coast	**8.03**	7.37	6.38
West	**6.13**	6.05	6.00
Canada	**5.47**	6.18	6.79
Weighted Average	**7.23**	7.13	6.74
Produced Crude/Condensate Sales Price *($/Bbl)* (1)			
East	**$ 66.97**	$ 62.03	$ 53.84
Gulf Coast	**67.17**	65.44	42.81
West	**67.86**	63.36	55.37
Canada	**59.96**	60.55	43.39
Weighted Average	**67.16**	65.03	44.19
Production Costs *($/Mcfe)* (2)			
East	**$ 1.37**	$ 1.12	$ 1.09
Gulf Coast	**1.44**	1.37	1.14
West	**1.27**	1.34	1.36
Canada	**0.84**	0.84	1.07
Weighted Average	**1.36**	1.31	1.23

(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, insurance and property and severance taxes, but is exclusive of depreciation and depletion applicable to capitalized lease acquisition, exploration and development expenditures.

Acreage

The following tables summarize our gross and net developed and undeveloped leasehold and mineral acreage at December 31, 2007. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

Leasehold Acreage by State

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alabama	0	0	5,391	3,965	5,391	3,965
Arkansas	1,981	425	0	0	1,981	425
Colorado	16,268	14,053	200,334	128,450	216,602	142,503
Kansas	29,387	28,065	0	160	29,387	28,225
Louisiana	8,247	6,088	20,069	19,197	28,316	25,285
Mississippi	0	0	405,731	263,605	405,731	263,605
Montana	397	210	9,031	8,654	9,428	8,864
New York	2,379	961	621	256	3,000	1,217
Ohio	6,260	2,384	21,405	20,216	27,665	22,600
Oklahoma	184,447	129,436	30,902	23,882	215,349	153,318
Pennsylvania	111,496	63,549	88,932	88,484	200,428	152,033
Texas	111,866	79,605	68,970	49,727	180,836	129,332
Utah	2,820	1,609	179,137	94,436	181,957	96,045
Virginia	7,106	5,010	2,773	1,689	9,879	6,699
West Virginia	597,793	564,969	266,953	244,435	864,746	809,404
Wyoming	139,103	72,002	221,772	127,374	360,875	199,376
Total	**1,219,550**	**968,366**	**1,522,021**	**1,074,530**	**2,741,571**	**2,042,896**

Mineral Fee Acreage by State

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Colorado	0	0	2,899	271	2,899	271
Kansas	160	128	0	0	160	128
Montana	0	0	589	75	589	75
New York	0	0	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	98,162	79,490	50,896	49,669	149,058	129,159
Total	**133,450**	**112,073**	**64,344**	**52,594**	**197,794**	**164,667**
Aggregate Total	**1,353,000**	**1,080,439**	**1,586,365**	**1,127,124**	**2,939,365**	**2,207,563**

Canada Leasehold Acreage by Province

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	14,240	6,917	102,984	35,110	117,224	42,027
British Columbia	700	280	11,988	4,730	12,688	5,010
Saskatchewan	0	0	4,549	1,365	4,549	1,365
Total	**14,940**	**7,197**	**119,521**	**41,205**	**134,461**	**48,402**

Total Net Leasehold Acreage by Region of Operation

	Developed	Undeveloped	Total
East	636,873	355,080	991,953
Gulf Coast	58,841	336,366	395,207
West	272,652	383,084	655,736
Canada	7,197	41,205	48,402
Total	**975,563**	**1,115,735**	**2,091,298**

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, 2007. The figures below assume no future successful development or renewal of undeveloped acreage.

	2008	2009	2010
East	47,435	18,917	35,325
Gulf Coast	33,605	65,970	162,843
West	87,181	38,556	65,197
Canada	13,975	4,656	—
Total	**182,196**	**128,099**	**263,365**

Well Summary

The following table presents our ownership at December 31, 2007, in productive natural gas and oil wells in the East region (consisting of various fields located in West Virginia, Virginia and Ohio), in the Gulf Coast region (consisting primarily of various fields located in Louisiana and Texas), in the West region (consisting of various fields located in Oklahoma, Kansas, Colorado, Utah and Wyoming) and in the Canada region (consisting of various fields located in the Province of Alberta). 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
East	3,153	2,950.2	25	12.0	3,178	2,962.2
Gulf Coast	567	356.3	118	107.8	685	464.1
West	1,400	810.6	55	33.2	1,455	843.8
Canada	37	12.9	1	0.5	38	13.4
Total	**5,157**	**4,130.0**	**199**	**153.5**	**5,356**	**4,283.5**

(1) Total does not include service wells of 54 (51.6 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, 2007									
	East		*Gulf Coast*		*West*		*Canada*		**Total**	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	**Gross**	**Net**
Development Wells										
Successful	248	238.8	80	61.0	96	63.1	5	2.8	**429**	**365.7**
Dry	1	1.0	3	2.5	7	5.8	0	0.0	**11**	**9.3**
Extension Wells										
Successful	1	1.0	4	3.0	0	0.0	3	1.2	**8**	**5.2**
Dry	0	0.0	0	0.0	0	0.0	0	0.0	**0**	**0.0**
Exploratory Wells										
Successful	3	2.8	1	0.5	0	0.0	2	1.2	**6**	**4.5**
Dry	1	1.0	4	4.0	2	1.2	0	0.0	**7**	**6.2**
Total	**254**	**244.6**	**92**	**71.0**	**105**	**70.1**	**10**	**5.2**	**461**	**390.9**
Wells Acquired	0	0.0	1	0.9	1	1.0	0	0.0	**2**	**1.9**
Wells in Progress at End of Year	2	2.0	9	5.2	2	1.1	1	0.2	**14**	**8.5**

	Year Ended December 31, 2006									
	East		*Gulf Coast*		*West*		*Canada*		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful	195	186.0	40	29.8	107	56.0	5	2.7	347	274.5
Dry	2	2.0	2	1.9	3	2.3	1	0.2	8	6.4
Extension Wells										
Successful	0	0.0	10	9.7	1	0.1	0	0.0	11	9.8
Dry	0	0.0	0	0.0	0	0.0	1	0.7	1	0.7
Exploratory Wells										
Successful	2	2.0	8	6.2	0	0.0	2	0.8	12	9.0
Dry	1	0.7	4	3.2	2	1.7	1	1.0	8	6.6
Total	200	190.7	64	50.8	113	60.1	10	5.4	387	307.0
Wells Acquired	5	5.0	0	0.0	0	0.0	1	0.4	6	5.4
Wells in Progress at End of Year	0	0.0	4	3.9	1	0.5	2	1.3	7	5.7

	Year Ended December 31, 2005									
	East		*West*		*Gulf Coast*		*Canada*		Total	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Development Wells										
Successful	182	176.8	75	32.6	19	13.7	5	1.6	281	224.7
Dry	0	0.0	3	1.8	0	0.0	0	0.0	3	1.8
Extension Wells										
Successful	0	0.0	1	0.4	3	2.7	0	0.0	4	3.1
Dry	0	0.0	0	0.0	1	1.0	0	0.0	1	1.0
Exploratory Wells										
Successful	3	3.0	1	0.7	10	6.0	1	0.7	15	10.4
Dry	0	0.0	3	2.1	6	2.8	3	1.2	12	6.1
Total	185	179.8	83	37.6	39	26.2	9	3.5	316	247.1
Wells Acquired	0	0.0	0	0.0	16	2.8	0	0.0	16	2.8
Wells in Progress at End of Year	3	3.0	3	2.0	5	3.0	3	1.1	14	9.1

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 East 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 2007 and 2006, no customer accounted for more than 10% of our total sales. In 2005, approximately 11% of our total sales were made to one customer.

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, the NGA has been amended to prohibit any forms of market manipulation in connection with the purchase or sale of natural gas. 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. The 2005 Act also significantly increases the penalties for violations of the NGA.

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 interim rules governing the relationship of pipelines with their marketing affiliates, and has initiated a rulemaking proceeding to consider whether to make those rules permanent. 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. 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. We have substantially completed the required initial inspection (baseline assessment) of our pipeline systems in West Virginia, and expect to complete that assessment within the required timeline. We are not able to predict with certainty the final outcome of these rules on our facilities or our business.

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 proceeding that may impact our transportation costs relates to an ongoing proceeding to determine whether and to what extent pipelines should be permitted to include in their transportation rates an allowance for income taxes attributable to non-corporate partnership interests. Following a court remand, the FERC has established a policy that a pipeline structured as a master limited partnership or similar non-corporate entity is entitled to 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 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 new 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 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 solid 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 disposed of or arranged for the 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 generated and will continue to 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 wastes have been disposed.

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 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 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 that are air emission sources. We believe that we substantially comply with the emission standards under local, state, and federal laws and regulations.

Employees

As of December 31, 2007, we had 404 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" and a copy will be provided, without charge, to any shareholder upon request. Requests can also be made in writing to Investor Relations at our corporate headquarters at 1200 Enclave Parkway, Houston, Texas, 77077. We have filed the required certifications of our chief executive officer and our chief financial officer under Section 302 of the Sarbanes-Oxley Act of 2002 as exhibits 31.1 and 31.2 to this Form 10-K. In 2007, we submitted to the New York Stock Exchange the chief executive officer certification required by Section 303A.12(a) of the NYSE's Listed Company Manual.

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. 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.

High demand for field services and equipment and the ability of suppliers to meet that demand may limit our ability to drill and produce our natural gas and oil properties.

Due to current industry demands, well service providers and related equipment and personnel are in short supply. This may cause escalating prices, delays in drilling and other exploration activities, the possibility of poor services coupled with potential damage to downhole reservoirs and personnel injuries. Such pressures would likely increase the actual cost of services, extend the time to secure such services and add costs for damages due to any accidents sustained from the over use of equipment and inexperienced personnel.

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 prices 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 in Statement of Financial Accounting Standards No. 69 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, 2007 will decline at estimated rates of three percent, 15%, 13% and 10% during 2008, 2009, 2010 and 2011, 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.

From time to time, we may identify and evaluate opportunities to acquire natural gas and oil properties. We may not be able to successfully consummate any acquisition, to acquire producing natural gas and oil properties that contain economically recoverable reserves, or to integrate the properties into our operations profitably.

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

Our business involves a variety of operating risks, including:

- blowouts, cratering and explosions;
- mechanical problems;
- 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, 2007, we owned or operated approximately 3,300 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.

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 4.7% of our owned net wells, as of December 31, 2007. 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 2007 we employed natural gas price collar and swap agreements and crude oil price collar agreements covering portions of our 2007 production and anticipated 2008 production to attempt to manage price risk more effectively. 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 is below the floor. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas 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.

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. We also have adopted a stockholder rights plan. Because of our stockholder rights plan and 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 certificate of incorporation.

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 certificate of incorporation 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.

West Virginia Royalty Litigation

In December 2001, we were sued by two royalty owners in West Virginia state court for an unspecified amount of damages. The plaintiffs requested class certification and alleged that we failed to pay royalty based upon the wholesale market value of the gas, that we had taken improper deductions from the royalty and that we failed to properly inform royalty owners of the deductions. The plaintiffs also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that we reached with Columbia Gas Transmission Corporation in 1995 bankruptcy proceedings. The Court entered an order on June 1, 2005 granting the motion for class certification.

The parties reached a tentative settlement in 2007, pursuant to which we paid $11.6 million into a trust fund which will disburse the settlement proceeds to the class members upon final approval of the settlement by the Court. These restricted cash funds are held by a financial institution in West Virginia under the joint custody of the plaintiffs and us. These funds have been classified within Other Current Assets in the Consolidated Balance Sheet. Subsequent to reaching the tentative settlement, it was determined that an additional payment of $0.4 million would be required to account for production from new wells that came on-line during the process of settlement negotiations and were not included in the volumes upon which the $11.6 million settlement was reached. The additional funds bring the total to be paid by us to $12.0 million.

In the tentative settlement, we also agreed with the class members to a methodology for payment of future royalties and the reporting format such methodology will take. The tentative settlement was not to be final or binding until approved by the Court. The hearing for final approval of the settlement was held on February 12, 2008. The Court approved the final settlement at the hearing. Upon filing of the written Order of Approval by the Court, the process will begin for distribution of the settlement proceeds from the trust. We had provided a reserve sufficient to cover the amount agreed upon to settle this litigation.

Commitment and Contingency Reserves

We have established 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 $8.4 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 2007.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 15, 2008 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	54	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	59	Senior Vice President, Chief Operating Officer	1998
Scott C. Schroeder	45	Vice President and Chief Financial Officer	1997
J. Scott Arnold	54	Vice President, Land and Associate General Counsel	1998
Robert G. Drake	60	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	61	Vice President, Human Resources	1998
Jeffrey W. Hutton	52	Vice President, Marketing	1995
Thomas S. Liberatore	51	Vice President, Regional Manager, East Region	2003
Lisa A. Machesney	52	Vice President, Managing Counsel and Corporate Secretary	1995
Henry C. Smyth	61	Vice President, Controller and Treasurer	1998

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.

PART II

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

The 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 the 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.

On February 23, 2007, our Board of Directors declared a 2-for-1 split of our 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, including cash dividends per share, have been retroactively adjusted to give effect to the 2-for-1 split of our common stock. After the stock split, the dividend was increased to $0.03 per share per quarter, or a 50% increase from pre-split levels.

	High	Low	Dividends
2007			
First Quarter	**$ 35.29**	**$ 28.06**	**$ 0.02**
Second Quarter	**41.88**	**34.55**	**0.03**
Third Quarter	**38.39**	**31.55**	**0.03**
Fourth Quarter	**40.90**	**33.59**	**0.03**
2006			
First Quarter	$ 26.01	$ 21.59	$ 0.02
Second Quarter	27.22	19.21	0.02
Third Quarter	27.58	22.08	0.02
Fourth Quarter	32.86	22.19	0.02

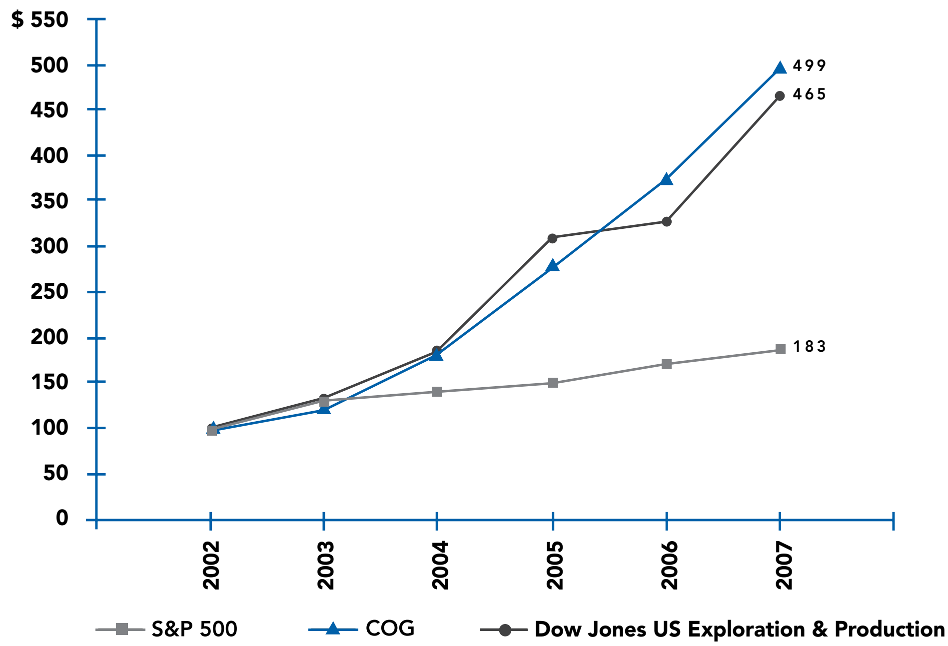
As of January 31, 2007, there were 574 registered holders of the common stock. Shareholders include individuals, brokers, nominees, custodians, trustees, and institutions such as banks, insurance companies and pension funds. Many of these hold large blocks of stock on behalf of other individuals or firms.

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 2007, 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, 2007 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 2002 through December 2007. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2002 and that all dividends were reinvested.



Calculated Values	2002	2003	2004	2005	2006	**2007**
S&P 500	100.0	128.7	142.7	149.7	173.3	**182.9**
COG	100.0	119.2	180.5	277.1	373.8	**499.1**
Dow Jones US Exploration & Production	100.0	131.1	185.9	307.4	323.9	**465.4**

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)	**2007**	2006	2005	2004	2003
Statement of Operations Data					
Operating Revenues	**$ 732,170**	$ 761,988	$ 682,797	$ 530,408	$ 509,391
Impairment of Oil and Gas Properties (1)	**4,614**	3,886	—	3,458	93,796
Gain / (Loss) on Sale of Assets (2)	**13,448**	232,017	74	(124)	12,173
Income from Operations	**274,693**	528,946	258,731	160,653	66,587
Net Income	**167,423**	321,175	148,445	88,378	21,132
Basic Earnings per Share (3)(4)	**$ 1.73**	$ 3.32	$ 1.52	$ 0.91	$ 0.22
Diluted Earnings per Share (3)(4)	**$ 1.71**	$ 3.26	$ 1.49	$ 0.90	$ 0.22
Dividends per Common Share (3)	**$ 0.110**	$ 0.080	$ 0.074	$ 0.054	$ 0.054
Balance Sheet Data					
Properties and Equipment, Net	**$ 1,908,117**	$ 1,480,201	$ 1,238,055	$ 994,081	$ 895,955
Total Assets	**2,208,594**	1,834,491	1,495,370	1,210,956	1,055,056
Current Portion of Long-Term Debt	**20,000**	20,000	20,000	20,000	—
Long-Term Debt	**330,000**	220,000	320,000	250,000	270,000
Stockholders' Equity	**1,070,257**	945,198	600,211	455,662	365,197

(1) For discussion of impairment of oil and gas properties, 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 the 2006 south Louisiana and offshore properties sale, which was substantially completed in the third quarter of 2006.

(3) 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.

(4) Year 2003 includes a cumulative effect of a change in accounting principle loss of $0.07 per share related to the adoption of SFAS No. 143 "Accounting for Asset Retirement Obligations."

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.

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 and Canada.

OVERVIEW

Cabot Oil & Gas and its subsidiaries are 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 North America. 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, there are three types of investment alternatives that compete for available capital: drilling opportunities, financial opportunities such as debt repayment or repurchase of common stock and, to a lesser extent, 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 2006 and 2007, the futures market reported strong natural gas and crude oil contract prices. Our realized natural gas and crude oil price was $7.23 per Mcf and $67.16 per Bbl, respectively, in 2007. These realized prices include the realized impact of derivative instruments. In an effort to manage commodity price risk, we entered into a series of crude oil and natural gas price collars. These financial instruments are an important element of our risk management strategy and assisted in the increase in our realized natural gas price from 2006 to 2007.

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 demands, 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 2006 and 2007. "Index" represents the first of the month Henry Hub index price per Mmbtu. The "2006" and "2007" 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 – 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 5.84	$ 6.93	$ 7.55	$ 7.56	$ 7.51	$ 7.59	$ 6.93	$ 6.11	$ 5.43	$ 6.43	$ 7.27	$ 7.21
2007	**$ 7.05**	**$ 7.61**	**$ 7.63**	**$ 7.04**	**$ 7.30**	**$ 7.38**	**$ 7.05**	**$ 6.94**	**$ 6.41**	**$ 7.06**	**$ 7.44**	**$ 7.87**

Natural Gas Prices by Month – 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$11.45	$ 8.46	$ 7.13	$ 7.25	$ 7.22	$ 5.93	$ 5.89	$ 7.04	$ 6.82	$ 4.20	$ 7.16	$ 8.33
2006	$ 9.79	$ 7.83	$ 7.11	$ 6.90	$ 7.02	$ 6.37	$ 6.49	$ 7.10	$ 6.71	$ 5.45	$ 7.27	$ 7.64

Prices for crude oil have maintained strength in 2006 and rose further in 2007. The tables below contain the NYMEX monthly average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2006 and 2007. The "2006" and "2007" 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 – 2007

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 54.67	$ 59.39	$ 60.74	$ 64.04	$ 63.53	$ 67.53	$ 74.15	$ 72.36	$ 79.63	$ 85.66	$ 94.63	$ 91.74
2007	**$ 51.59**	**$ 53.17**	**$ 55.54**	**$ 61.31**	**$ 63.35**	**$ 61.42**	**$ 70.68**	**$ 70.03**	**$ 71.90**	**$ 83.97**	**$ 84.38**	**$ 82.65**

Crude Oil Prices by Month – 2006

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 65.54	$ 61.93	$ 62.97	$ 70.16	$ 70.96	$ 70.97	$ 74.46	$ 73.08	$ 63.90	$ 59.14	$ 59.40	$ 62.09
2006	$ 63.53	$ 60.83	$ 59.28	$ 68.27	$ 68.56	$ 68.12	$ 74.03	$ 73.01	$ 60.87	$ 53.88	$ 55.97	$ 59.47

We reported earnings of $1.73 per share, or $167.4 million, for 2007. This is down from the $3.32 per share, or $321.2 million, reported in 2006. Earnings decreased from 2006 to 2007 primarily due to the $231.2 million ($144.5 million, net of tax) gain recorded in 2006 related to the 2006 south Louisiana and offshore properties sale. Natural gas revenues increased from 2006 to

2007 as a result of an increase in realized prices, resulting from favorable natural gas hedge settlements, and increased natural gas production. Crude oil revenues decreased from 2006 to 2007 primarily due to decreased Gulf Coast production related primarily to the 2006 south Louisiana and offshore properties sale. Prices, including the realized impact of derivative instruments, increased by one percent for natural gas and three percent for oil.

We drilled 461 gross wells with a success rate of 96% in 2007 compared to 387 gross wells with a success rate of 96% in 2006. Total capital and exploration expenditures increased by $98.7 million to $636.2 million in 2007 compared to $537.5 million in 2006. We believe our cash on hand and operating cash flow in 2008 will be sufficient to fund a substantial portion of our budgeted capital and exploration spending of approximately $490 million. Any additional needs will be funded by borrowings from our credit facility.

Our 2008 strategy will remain consistent with 2007. We will remain focused on our strategy of pursuing lower risk drilling opportunities that provide more predictable results on our accumulated acreage position. Additionally, we will continue to add to our acreage position in certain areas for future drilling opportunities. In the current year we have allocated our planned program for capital and exploration expenditures among our various operating regions. We believe that these strategies are appropriate for our portfolio of projects and the current industry environment and that this activity 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 2007 were from funds generated from the sale of natural gas and crude oil production and borrowings under our revolving credit facility. Cash flows provided by operating activities were primarily used to fund development and, to a lesser extent, exploratory expenditures, and to pay 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. 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.

Working capital is also substantially influenced by these 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 liquidity available to meet our working capital requirements.

	Year Ended December 31,		
(In thousands)	**2007**	2006	2005
Cash Flows Provided by Operating Activities	**$ 462,137**	$ 357,104	$ 364,560
Cash Flows Used in Investing Activities	**(589,922)**	(187,353)	(412,150)
Cash Flows Provided by / (Used in) Financing Activities	**104,429**	(138,523)	48,190
Net (Decrease) / Increase in Cash and Cash Equivalents	**$ (23,356)**	$ 31,228	$ 600

Operating Activities. Net cash provided by operating activities in 2007 increased by $105.0 million over 2006. This increase was mainly due to a decrease in cash paid for current income taxes from 2006 to 2007 primarily due to the 2006 payment of approximately $102 million related to the 2006 south Louisiana and offshore properties sale, as well as our 2007 tax net operating loss position and the receipt in 2007 of $29.6 million in federal tax refunds relating to our 2006 tax return. Key components impacting net operating cash flows are commodity prices, production volumes and operating costs. Average realized natural gas prices increased by one percent in 2007 over 2006 and average crude oil realized prices increased by three percent over the same period. Equivalent production decreased by three percent in 2007 compared to 2006 as a result of a decrease in crude oil production, offset in part by an increase in natural gas 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.

Net cash provided by operating activities in 2006 decreased by $7.5 million over 2005. This decrease was primarily due to an increase in current income tax expense, partially offset by an increase in earnings and an increase in working capital changes. The increase in cash paid for income taxes from 2005 to 2006 is primarily due to the December 2006 payment of approximately $102 million related to the 2006 south Louisiana and offshore properties sale. Other factors impacting net operating cash flows are commodity prices, production volumes and operating costs. Average realized natural gas prices increased six percent over 2005, while crude oil realized prices increased 47% over the same period. Equivalent production increased by five percent in 2006 compared to 2005.

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. 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 increased by $402.6 million from 2006 to 2007 and decreased by $224.8 million from 2005 to 2006. The increase from 2006 to 2007 was due to a decrease of $322.4 million in 2007 in proceeds from the sale of assets and an increase of $89.8 million in 2007 in capital expenditures, partially offset by reduced exploration expenses of $9.6 million.

Cash flows used in investments in capital and exploration expenditures were $516.8 million in 2006 compared to $413.1 million used in 2005, in response to higher commodity prices. This increase of $103.7 million in investments in capital and exploration expenses was entirely offset by the increase of $328.5 million in proceeds from the sale of assets, primarily as a result of the 2006 south Louisiana and offshore properties sale.

Financing Activities. Cash flows provided by financing activities were $104.4 million for 2007, and contained a net increase in borrowings under our revolving credit facility and proceeds from the exercise of stock options, partially offset by dividend payments. Cash flows used in financing activities were $138.5 million for 2006, and were comprised of payments made to decrease outstanding debt under our revolving credit facility, to purchase treasury stock and to pay dividends. Partially offsetting these cash uses were inflows from the exercise of stock options and the tax benefit received from stock-based compensation. Cash flows provided by financing activities were $48.2 million for 2005, resulting from borrowings under the credit facility, partially offset by the purchase of treasury stock and dividend payments.

At December 31, 2007, we had $140 million of borrowings outstanding under our credit facility at a weighted-average interest rate of 6.9%. The credit facility provides for an available credit line of $250 million, which can be expanded up to $350 million, either with the existing banks or new banks. 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' petroleum engineer) and other assets. The revolving term of the credit facility ends in December 2009. We strive to manage our debt at a level below the available credit line in order to maintain excess borrowing capacity. Management believes that we have the ability to finance through new debt or equity offerings, if necessary, our capital requirements, including potential acquisitions.

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. We did not repurchase any shares of our common stock during 2007. 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, 2007 was 4,795,300. See Item 5 "Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities" for additional information.

Capitalization

Information about our capitalization is as follows:

	December 31,	
(Dollars in millions)	**2007**	2006
Debt [1]	**$ 350.0**	$ 240.0
Stockholders' Equity	**1,070.3**	945.2
Total Capitalization	**$ 1,420.3**	$ 1,185.2
Debt to Capitalization	**25%**	20%
Cash and Cash Equivalents	**$ 18.5**	$ 41.9

(1) Includes $20.0 million of current portion of long-term debt at both December 31, 2007 and 2006. Includes $140 million and $10 million of borrowings outstanding under our revolving credit facility at December 31, 2007 and 2006, respectively.

For the year ended December 31, 2007, we paid dividends of $10.7 million on our common stock. A regular dividend has been declared for each quarter since we became a public company in 1990. After the March 2007 2-for-1 stock split, the dividend was increased to $0.03 per share per quarter, or a 50% increase from pre-split levels.

Increase in Authorized Shares

On May 4, 2006, our stockholders approved an increase in the authorized number of shares of our common stock from 80 million to 120 million shares. We correspondingly increased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 800,000 to 1,200,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to our Rights Agreement with The Bank of New York, as Rights Agent.

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, 2007.

(In millions)	**2007**	2006	2005
Capital Expenditures			
Drilling and Facilities	**$ 524.7**	$ 406.9	$ 249.3
Leasehold Acquisitions	**22.2**	42.6	22.1
Pipeline and Gathering	**28.2**	24.2	17.9
Other	**17.3**	7.7	1.4
	592.4	481.4	290.7
Proved Property Acquisitions	**4.0**	6.7	73.1
Exploration Expense	**39.8**	49.4	61.8
Total	**$ 636.2**	$ 537.5	$ 425.6

We plan to drill approximately 419 gross wells (366 net) in 2008 compared with 461 gross wells (391 net) drilled in 2007. The number of wells we plan to drill in 2008 is down from 2007 primarily due to lower planned activity in the Rocky Mountains area based on lower natural gas prices and lower planned activity in Canada based on uncertainty around royalties and exchange rates. This 2008 drilling program includes approximately $490 million in total capital and exploration expenditures, down from $636.2 million in 2007. We will continue to assess the natural gas price environment 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 a future period. In 2008, 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. This change is currently estimated to be approximately five percent greater than 2007 levels. This increase will not have an impact on our cash flows.

Contractual Obligations

Our known 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.

During 2006, we assisted certain non-executive employees in obtaining loans to purchase interests offered under our Mineral, Royalty and Overriding Royalty Interest Plan by providing a guarantee of repayment should the non-executive employee fail to repay the loan. The repayment term for all of these loans was five years. The outstanding loan balances were approximately $0.3 million in the aggregate as of December 31, 2006 and the fair value of these guarantees were immaterial to our financial statements. There were no outstanding loan balances as of December 31, 2007. All loans were collateralized by the interests transferred to the employees in the producing properties.

A summary of our known contractual obligations as of December 31, 2007 are set forth in the following table:

		Payments Due by Year			
(In thousands)	**Total**	2008	2009 to 2010	2011 to 2012	2013 & Beyond
Long-Term Debt [1]	**$ 350,000**	$ 20,000	$ 160,000	$ 75,000	$ 95,000
Interest on Long-Term Debt [2]	**91,960**	24,992	36,011	19,469	11,488
Firm Gas Transportation Agreements [3]	**82,165**	9,937	16,859	7,876	47,493
Drilling Rig Commitments [3]	**71,332**	41,180	30,152	—	—
Operating Leases [3]	**11,512**	5,414	5,387	711	—
Total Contractual Cash Obligations	**$ 606,969**	**$101,523**	**$ 248,409**	**$ 103,056**	**$ 153,981**

(1) Including current portion. At December 31, 2007, we had $140 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 $210 million long-term debt outstanding at December 31, 2007. Interest payments on our revolving credit facility were calculated by assuming that the December 31, 2007 outstanding balance of $140 million will be outstanding through the 2009 maturity date and by assuming a constant interest rate of 6.9%, which was the December 31, 2007 weighted–average interest rate. Actual results will likely 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, 2007 was $24.7 million, up from $22.7 million at December 31, 2006, primarily due to $1.0 million of accretion expense during 2007 as well as $1.6 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. We have not been required to record a significant reserve revision in the past three years. 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 $0.08 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 $0.01 to $0.02 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 annual impairment test under Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." 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 lease-by-lease 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 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 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. In 2007, 2006 and 2005, there were no unusual or unexpected occurrences that caused significant revisions in estimated cash flows which were utilized in our impairment test.

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 lives in each of the regions have not significantly changed. If the average unproved property life decreases or increases by one year, the amortization would increase by approximately $8.6 million or decrease by approximately $6.5 million, respectively per year.

In the past, the average leasehold life in the Gulf Coast region has been shorter than the average life in the East and West regions. Average property lives in the East, Gulf Coast and West regions have been six, four and seven years, respectively. Average property lives in Canada are estimated to be five years. 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

Periodically, we enter into derivative commodity instruments to hedge our exposure to price fluctuations on natural gas and crude oil production. We follow the accounting prescribed in SFAS No. 133. Under SFAS No. 133, 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 SFAS No. 133, 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 all other derivatives, 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.

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 5.8% as of December 31, 2007, and the Citigroup Pension Liability Index, which was 6.48% as of December 31, 2007. 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 6.0% at December 31, 2007 is reasonable.

In order to value our pension liabilities, we use the RP-2000 Combined Mortality Table. This is a widely accepted table used for valuing pension liabilities. This table represents a more recent and conservative mortality table than the 1983 Group Annuity Mortality Table, and appears to be an appropriate table based on the demographics of our benefit plans. Another consideration that is made is a salary scale selection. We have 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, 2007, the assumed rate of increase was 9.0%. 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. In our pension calculations, we have used eight percent as the expected long-term return on plan assets for 2007, 2006 and 2005. 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 16 years. This model uses historical data for the period of 1926-2003 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 a minimum 6.4% annual real rate of return on the total portfolio over the long term at least 75 percent of the time. In addition, the actual rate of return on plan assets annualized over the past ten years is approximately six percent. 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

Effective January 1, 2006, we adopted the accounting policies described in SFAS No. 123(R), "Share Based Payment (revised 2004)." We chose to use the modified prospective method of transition, and accordingly, no adjustments to prior period financial statements were made. Prior to January 1, 2006, we accounted for stock-based compensation in accordance with the intrinsic value based method prescribed by Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees." Under this method, we recognized compensation cost as the excess, if any, of the quoted market price of our stock at the grant date over the amount an employee must pay to acquire the stock. In addition, SFAS No. 123, "Accounting for Stock-Based Compensation," as amended by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure," outlines a fair value based method of accounting for stock options or 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.

One primary difference in our method of accounting after the adoption of SFAS No. 123(R) is that unvested stock options are now expensed as a component of Stock-Based Compensation cost in General and Administrative Expense in the Consolidated Statement of Operations. This expense is based on the fair value of the award at the original grant date and is recognized over the vesting period. Prior to the adoption of SFAS No. 123(R), we included this amount as a pro-forma disclosure in the Notes to the Consolidated Financial Statements. The expense resulting from the expensing of stock options was $0.1 million and $0.3 million for the years ended December 31, 2007 and 2006, respectively. Another change relates to the accounting for our performance share awards. Certain of these awards are now accounted for by bifurcating the equity and liability components. A Monte Carlo model is used to value the liability component, rather than accounting for the award using the average closing stock price at the end of each reporting period. All other awards are accounted for in substantially the same way as they were or would have been in prior periods, with the exception of the differences noted below.

Other differences in the way we account for stock-based compensation after January 1, 2006, result from the application of a forfeiture rate to all grants rather than only recording actual forfeitures as they occur. We are now required to estimate forfeitures on all equity-based compensation and adjust periodic expense. Upon adoption, we did not report a cumulative effect adjustment for these forfeitures as the amount was immaterial. In addition, this change in accounting for forfeitures resulted in an immaterial change in overall compensation cost for the years ended December 31, 2007 and 2006. Furthermore, we are required to expense certain awards to retirement-eligible employees in the month an employee becomes retirement eligible, depending on the structure of each individual plan. The retirement-eligibility provision only applies to new grants that were awarded after January 1, 2006. The total expense that we recognized related to restricted stock awards and stock appreciation rights granted to retirement-eligible employees in 2007 and 2006 was $0.6 million in each year.

We issued stock appreciation rights to executive officers for the first time during the first quarter of 2006. The grant date fair value of these awards is measured using a Black-Scholes model and compensation cost is expensed over the three year graded-vesting service period. Expense related to these awards was $1.5 million and $1.0 million, before the effect of taxes, for 2007 and 2006, respectively.

In addition, two new types of performance shares were issued to employees during 2007 and 2006. During 2007, we issued to executive officers a new type of performance share award that vests depending on our operating income. These awards vest based on a three-year graded vesting service period, vesting one-third on each anniversary date following the date of grant, provided that we have positive operating income. If we do not have positive operating income for the year preceding a vesting date, then the portions of the award that would have vested on that date will be forfeited. Compensation cost related to these new operating-income based performance share awards granted to employees was $1.7 million, before the effect of taxes, for 2007. A second new type of performance share award, issued to non-executive employees for the first time in 2006 and again in 2007, measures our performance based on three internal metrics, rather than a peer group's stock performance which we use to measure certain other performance share awards. These awards cliff vest at the end of the three year service period. Compensation cost related to these internal-metric based performance share awards granted to employees was $4.7 million and $1.4 million, before the effect of taxes, for 2007 and 2006, respectively. Total performance share expense related to all types of performance share awards, before the effect of taxes, was $9.4 million for 2007 and $12.9 million for 2006. A $0.6 million ($0.4 million, net of tax) cumulative effect charge incurred during the first quarter of 2006 is included in 2006 performance share expense within General and Administrative Expenses due to its immateriality, as a result of changes made in our accounting for performance shares. For further information on the accounting for these and our other stock-based compensation awards, please refer to Notes 1 and 10 of the Notes to the Consolidated Financial Statements.

During the third quarter of 2006, we adopted the provisions outlined under Financial Accounting Standard Board (FASB) Staff Position (FSP) FAS No. 123(R)-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards," which discusses accounting for taxes for stock awards using the APIC Pool concept. We made a one time election as prescribed under the FSP to use the shortcut approach to derive the initial windfall tax benefit pool. We chose to use a one-pool approach which combines all awards granted to employees, including non-employee directors.

Our Compensation Committee of our Board of Directors made one modification to our stock option awards in 2005. It approved the acceleration to December 15, 2005 of the vesting of 198,799 unvested stock options awarded in February 2003 under our Second Amended and Restated 1994 Long-Term Incentive Plan and 24,500 unvested stock options awarded in April 2004 under our 2004 Incentive Plan.

The 198,799 shares awarded to employees under the 1994 plan at an exercise price of $15.32 would have vested in February 2006. The 24,500 shares awarded to non-employee directors under the 2004 plan at an exercise price of $23.32 would have vested 12,250 shares in each of April 2006 and April 2007. The decision to accelerate the vesting of these unvested options, which we believed to be in the best interest of our shareholders and employees, was made solely to reduce compensation expense and administrative burden associated with our adoption of SFAS No. 123(R). The accelerated vesting of the options did not have an impact on our results of operations or cash flows for 2005. The acceleration of vesting reduced our compensation expense related to these options by approximately $0.2 million for 2006.

Uncertain Tax Positions

Effective January 1, 2007, we adopted the provisions of FASB Interpretation Number (FIN) 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109." This adoption did not have a material impact on our financial statements. This Interpretation provides guidance for recognizing and measuring uncertain tax positions as defined in SFAS No. 109, "Accounting for Income Taxes." Under FIN 48, we now conduct a two-step process for accounting for income tax uncertainties. First, we perform an analysis to determine if a threshold condition of "more likely than not" is met to determine whether any of the benefit of the uncertain tax position should be recognized in the financial statements. Next, if the recognition threshold is met, we measure the amount of the uncertain tax position to be recognized based on additional guidance prescribed in FIN 48. Under FIN 48, we 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. 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. For further information regarding the adoption of FIN No. 48, please refer to Note 6 of the Notes to the Consolidated Financial Statements.

OTHER ISSUES AND CONTINGENCIES

Corporate Income Tax. We have benefited in the past and may benefit in the future from the alternative minimum tax (AMT) relief granted under the Comprehensive National Energy Policy Act of 1992 (the Act). The Act repealed provisions of the AMT requiring a taxpayer's alternative minimum taxable income to be increased on account of certain intangible drilling costs (IDC) and percentage depletion deductions for corporations other than integrated oil companies. The repeal of these provisions generally applies to taxable years beginning after 1992. The repeal of the excess IDC preference cannot reduce a taxpayer's alternative minimum taxable income by more than 40% of the amount of such income determined without regard to the repeal of such preference.

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. At December 31, 2007, we are 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. During the past few years, we have invested a significant portion of our drilling dollars in the Gulf Coast, where insurance rates are significantly higher than in other regions such as the East.

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 impact the outcome of our annual impairment test under SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." 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 commodity indexes fall, 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 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 risk that the movement of the index prices will result in our not being able to realize the full benefit of a market improvement.

Recently Issued Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in the equity in the consolidated financial statements separately from the parent's equity. Subsequent changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. At this time, we do not have any material noncontrolling interests in consolidated subsidiaries. Therefore, we do not believe that the adoption of SFAS No. 160 will have a material impact on our financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a "business" and a "business combination" have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. We cannot predict the impact that the adoption of SFAS No. 141(R) will have on our financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2007.

In May 2007, the FASB issued FSP No. FIN 48-1, "Definition of *Settlement* in FASB Interpretation No. 48," which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is "effectively," rather than the previously required "ultimately," settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FSP No. FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FSP No. FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. We have adopted FSP No. FIN 48-1 and no retroactive adjustments were necessary.

In April 2007, the FASB issued FSP No. FIN 39-1, "Amendment of FASB Interpretation No. 39," to amend FIN 39, "Offsetting of Amounts Related to Certain Contracts." The terms "conditional contracts" and "exchange contracts" used in FIN 39 have been replaced with the more general term "derivative contracts." In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a company's accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. We do not believe that the adoption of FSP No. FIN 39-1 will have a material impact on our financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115," which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of this Statement is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of the Statement apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. Since we have not elected to adopt the fair value option for eligible items, we do not believe that SFAS No. 159 will have an impact on our financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles (GAAP) to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. In November 2007, the FASB granted a one year deferral (to fiscal years beginning after November 15, 2008) for non-financial assets and liabilities to comply with SFAS No. 157. We do not believe that SFAS No. 157 will have a material impact on our financial position or results of operations.

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

2007 and 2006 Compared

We reported net income for the year ended December 31, 2007 of $167.4 million, or $1.73 per share. During 2006, we reported net income of $321.2 million, or $3.32 per share. This decrease of $153.8 million in net income was primarily due to a decrease in operating income of $254.2 million resulting from the gain on sale of assets of $231.2 million included in 2006 related to the 2006 south Louisiana and offshore properties sale, partially offset by a $99.2 million decrease in income tax expense and a $1.2 million decrease in interest and other expenses in 2007.

The decrease in operating income was primarily the result of a decrease in 2007 of $218.6 million in gain on sale of assets primarily from the 2006 south Louisiana and offshore properties sale. Additionally, there was a $29.8 million decrease in 2007 in operating revenues and an increase of $5.8 million in operating expenses. The decrease in operating revenues was largely the result of lower oil production in the Gulf Coast region primarily as a result of the 2006 south Louisiana and offshore properties sale. The increase in operating expenses was primarily the result of increased DD&A and impairment expenses, offset in part by reduced exploration and general and administrative expenses.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $7.23 per Mcf for 2007 compared to $7.13 per Mcf for 2006. These prices include the realized impact of derivative instrument settlements, which increased the price by $0.99 per Mcf in 2007 and $0.35 per Mcf in 2006. There was no revenue impact from the unrealized change in natural gas derivative fair value for the years ended December 31, 2007 or 2006.

	Year Ended December 31,		Variance	
	2007	2006	Amount	Percent
Natural Gas Production *(Mmcf)*				
East	**24,344**	23,542	802	3%
Gulf Coast	**26,797**	29,973	(3,176)	(11%)
West	**25,409**	23,633	1,776	8%
Canada	**3,925**	2,574	1,351	52%
Total Company	**80,475**	79,722	753	1%
Natural Gas Production Sales Price *($/Mcf)*				
East	**$ 7.78**	$ 7.99	$ (0.21)	(3%)
Gulf Coast	**$ 8.03**	$ 7.37	$ 0.66	9%
West	**$ 6.13**	$ 6.05	$ 0.08	1%
Canada	**$ 5.47**	$ 6.18	$ (0.71)	(11%)
Total Company	**$ 7.23**	$ 7.13	$ 0.10	1%
Natural Gas Production Revenue *(In thousands)*				
East	**$ 189,392**	$ 188,111	$ 1,281	1%
Gulf Coast	**215,106**	221,020	(5,914)	(3%)
West	**155,676**	143,058	12,618	9%
Canada	**21,466**	15,908	5,558	35%
Total Company	**$ 581,640**	$ 568,097	$ 13,543	2%
Price Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ (5,127)**			
Gulf Coast	**17,774**			
West	**2,121**			
Canada	**(2,792)**			
Total Company	**$ 11,976**			
Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*				
East	**$ 6,408**			
Gulf Coast	**(23,688)**			
West	**10,497**			
Canada	**8,350**			
Total Company	**$ 1,567**			

The increase of $13.5 million in Natural Gas Production Revenue is due to an increase in realized natural gas sales prices as well as increased natural gas production. Natural gas revenues increased in all regions except for the Gulf Coast region in 2007 over 2006. After removing from the 2006 results $70.5 million of natural gas revenues and 9,037 Mmcf of natural gas production associated with properties in the Gulf Coast region sold in the 2006 south Louisiana and offshore properties sale, total natural gas revenue would have increased by $84.0 million, or 17%, and natural gas production would have increased by 9,791 Mmcf, or 14%, from 2006 to 2007.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,		Variance	
	2007	2006	Amount	Percent
Sales Price *($/Mcf)*	**$ 8.40**	$ 8.14	$ 0.26	3%
Volume Brokered *(Mmcf)*	**11,101**	11,502	(401)	(3%)
Brokered Natural Gas Revenues *(In thousands)*	**$ 93,215**	$ 93,651		
Purchase Price *($/Mcf)*	**$ 7.37**	$ 7.25	$ 0.12	2%
Volume Brokered *(Mmcf)*	**11,101**	11,502	(401)	(3%)
Brokered Natural Gas Cost *(In thousands)*	**$ 81,819**	$ 83,375		
Brokered Natural Gas Margin *(In thousands)*	**$ 11,396**	$ 10,276	$ 1,120	11%
(In thousands)				
Sales Price Variance Impact on Revenue	**$ 2,828**			
Volume Variance Impact on Revenue	**(3,264)**			
	$ (436)			
(In thousands)				
Purchase Price Variance Impact on Purchases	**$ (1,351)**			
Volume Variance Impact on Purchases	**2,907**			
	$ 1,556			

The increased brokered natural gas margin of approximately $1.1 million is driven by an increase in sales price that outpaced the increase in purchase price, partially offset by a decrease in the volumes brokered in 2007 over 2006.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price was $67.16 per Bbl for 2007. The 2007 price includes the realized impact of derivative instrument settlements which decreased the price by $0.97 per Bbl. Our average total company realized crude oil sales price was $65.03 per Bbl for 2006. There was no realized impact of crude oil derivative instruments in 2006. There was no unrealized impact of crude oil derivative instruments in 2007 or 2006.

	Year Ended December 31,		Variance	
	2007	2006	Amount	Percent
Crude Oil Production *(Mbbl)*				
East	**26**	24	2	8%
Gulf Coast	**605**	1,160	(555)	(48%)
West	**174**	209	(35)	(17%)
Canada	**18**	12	6	50%
Total Company	**823**	1,405	(582)	(41%)
Crude Oil Sales Price *($/Bbl)*				
East	**$ 66.97**	$ 62.03	$ 4.94	8%
Gulf Coast	**$ 67.17**	$ 65.44	$ 1.73	3%
West	**$ 67.86**	$ 63.36	$ 4.50	7%
Canada	**$ 59.96**	$ 60.55	$ (0.59)	(1%)
Total Company	**$ 67.16**	$ 65.03	$ 2.13	3%
Crude Oil Revenue *(In thousands)*				
East	**$ 1,734**	$ 1,474	$ 260	18%
Gulf Coast	**40,673**	75,894	(35,221)	(46%)
West	**11,784**	13,253	(1,469)	(11%)
Canada	**1,052**	759	293	39%
Total Company	**$ 55,243**	$ 91,380	$ (36,137)	(40%)
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 128**			
Gulf Coast	**1,048**			
West	**781**			
Canada	**(10)**			
Total Company	**$ 1,947**			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	**$ 132**			
Gulf Coast	**(36,269)**			
West	**(2,250)**			
Canada	**303**			
Total Company	**$ (38,084)**			

The decrease in the realized crude oil production, partially offset by the increase in realized prices, resulted in a net revenue decrease of approximately $36.2 million. The decrease in oil production is mainly the result of the 2006 south Louisiana and offshore properties sale in the Gulf Coast region. After removing from the 2006 results $47.4 million of crude oil revenues and 707 Mbbls of crude oil production associated with properties in the Gulf Coast region sold in the 2006 south Louisiana and offshore properties sale, total crude oil revenue would have increased by $11.2 million, or 26%, and crude oil production would have increased by 124 Mbbls, or 18%, from 2006 to 2007.

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,			
	2007		2006	
(In thousands)	**Realized**	**Unrealized**	Realized	Unrealized
Operating Revenues - Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	**$ 79,838**	**$ —**	$ 28,266	$ —
Crude Oil	**(796)**	**—**	—	—
Total Cash Flow Hedges	**$ 79,042**	**$ —**	$ 28,266	$ —

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.

Operating Expenses

Total costs and expenses from operations increased by $5.8 million for the year ended December 31, 2007 compared to the year ended December 31, 2006. The primary reasons for this fluctuation are as follows:

- Depreciation, Depletion and Amortization increased by $14.9 million in 2007 over 2006. This is primarily due to the impact on the DD&A rate of negative reserve revisions due to lower prices at the end of 2006, higher capital costs and commencement of production in an east Texas field.
- Exploration expense decreased by $9.6 million from 2006 to 2007, primarily as a result of a decrease in total dry hole expense of $10.3 million, primarily in Canada and, to a lesser extent, in the West and Gulf Coast regions. In addition, there was a decrease in geophysical and geological expenses of $1.8 million, primarily due to a decrease in the Gulf Coast region, offset in part by an increase in Canada. Offsetting part of these decreases was an increase of $2.6 million in land and lease search expenses during 2007.
- Impairment of Unproved Properties increased by $7.9 million in 2007 compared to 2006, primarily due to increased lease acquisition costs during 2005 and 2006 in several exploratory areas.
- General and Administrative expense decreased by $7.4 million in 2007 primarily due to decreased stock compensation charges of $5.9 million as well as $4.2 million in decreased professional services fees for litigation. Partially offsetting these decreases were increases in employee compensation related expenses and bad debt expense.
- Direct Operations expense increased by $2.4 million as a result of higher employee compensation charges and disposal, treating, compressor, workover and maintenance costs, partially offset by lower outside operated properties expense and insurance expense.
- Brokered Natural Gas Cost decreased by $1.6 million from 2006 to 2007. See the preceding table labeled "Brokered Natural Gas Revenue and Cost" for further analysis.
- Taxes Other Than Income decreased by $1.5 million for 2007 compared to 2006, primarily due to decreased production taxes of $3.3 million as a result of decreased commodity volumes and prices as well as decreased franchise taxes, partially offset by an increase in ad valorem taxes.
- Impairment of Oil and Gas Properties increased by $0.7 million for the year ended December 31, 2007 compared to the year ended December 31, 2006, due to an impairment recorded in 2007 in the Gulf Coast region resulting from two non-commercial development completions in a small field in north Louisiana.

Interest Expense, Net

Interest expense, net decreased by $1.1 million in 2007 compared to 2006 due to a lower weighted-average interest rate on borrowings under our revolving credit facility, a lower outstanding principal amount of our 7.19% fixed rate debt and lower weighted-average borrowings under our credit facility, as well as increased income related to FIN 48 as discussed below. These decreases to interest expense were offset in part by decreased regulatory capitalized interest on our pipeline in the East region. Weighted-average borrowings under our credit facility based on daily balances were approximately $52 million during 2007 compared to approximately $61 million during 2006. The weighted-average effective interest rate on the credit facility decreased to 7.2% during 2007 from 7.9% during 2006. In addition, interest expense decreased due to the reversal of interest payable on a previous uncertain tax position. During 2007, we recorded net interest income related to FIN 48 of $1.3 million, with no amount recorded in 2006.

Income Tax Expense

Income tax expense decreased by $99.2 million due to a comparable decrease in our pre-tax income, primarily as a result of the decrease in the gain on sale of assets. The effective tax rates for 2007 and 2006 were 35.0% and 37.1%, respectively. The decrease in the effective tax rate is primarily due to a reduction in our overall state income tax rate for 2007.

2006 and 2005 Compared

We reported net income for the year ended December 31, 2006 of $321.2 million, or $3.32 per share. During 2005, we reported net income of $148.4 million, or $1.52 per share. Net income increased in 2006 by $172.8 million primarily due to an increase in operating income as a result of the gain of $231.2 million ($144.5 million, net of tax) recorded in 2006 related to the 2006 south Louisiana and offshore properties sale as well as an increase in natural gas and oil production revenues. This increase is partially offset by an increase in total operating expenses of $41.0 million and an increase of $101.5 million in income tax expense. Operating income increased by $270.2 million compared to the prior year, from $258.7 million in 2005 to $528.9 million in 2006.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price for 2006, including the realized impact of derivative instruments, was $7.13 per Mcf compared to $6.74 per Mcf for the prior year. These prices include the realized impact of derivative instruments, which increased these prices by $0.35 per Mcf in 2006 and reduced these prices by $1.33 per Mcf in 2005. The following table excludes the unrealized gain from the change in derivative fair value of $1.1 million for the year ended December 31, 2005. There was no unrealized impact from the change in derivative fair value for the year ended December 31, 2006. These unrealized changes in fair value have been included in Natural Gas Production Revenues in the Consolidated Statement of Operations.

	Year Ended December 31,		Variance	
	2006	2005	Amount	Percent
Natural Gas Production *(Mmcf)*				
East	23,542	21,435	2,107	10%
Gulf Coast	29,973	28,071	1,902	7%
West	23,633	23,224	409	2%
Canada	2,574	1,149	1,425	124%
Total Company	79,722	73,879	5,843	8%
Natural Gas Production Sales Price *($/Mcf)*				
East	$ 7.99	$ 8.02	$ (0.03)	0%
Gulf Coast	$ 7.37	$ 6.38	$ 0.99	16%
West	$ 6.05	$ 6.00	$ 0.05	1%
Canada	$ 6.18	$ 6.79	$ (0.61)	(9%)
Total Company	$ 7.13	$ 6.74	$ 0.39	6%
Natural Gas Production Revenue *(In thousands)*				
East	$ 188,111	$ 171,902	$ 16,209	9%
Gulf Coast	221,020	179,061	41,959	23%
West	143,058	139,298	3,760	3%
Canada	15,908	7,802	8,106	104%
Total Company	$ 568,097	$ 498,063	$ 70,034	14%

Price Variance Impact on Natural Gas Production Revenue *(In thousands)*	
East	$ (692)
Gulf Coast	29,822
West	1,189
Canada	(1,572)
Total Company	$ 28,747

Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*	
East	$ 16,901
Gulf Coast	12,137
West	2,571
Canada	9,678
Total Company	$ 41,287

The increase in Natural Gas Production Revenue is due to the increase in natural gas sales production and, to a lesser extent, the increase in realized natural gas prices. Production increased in all regions and prices were up in the Gulf Coast and West. The increase in the total realized natural gas price and production resulted in a net revenue increase of $70.0 million, excluding the unrealized impact of derivative instruments. This growth primarily resulted from our 2005 and 2006 drilling programs, which focused on projects in basins traditionally known for gas development, including the East region, the Minden field in the Gulf Coast and Canada. This natural gas production increase includes the effects of the 2006 south Louisiana and offshore properties sale. For the year ended December 31, 2006, natural gas volumes from the properties sold in the third quarter 2006 disposition were 9,037 Mmcf and natural gas revenues from those properties were approximately $70.5 million.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,		Variance	
	2006	2005	Amount	Percent
Sales Price *($/Mcf)*	$ 8.14	$ 9.14	$ (1.00)	(11%)
Volume Brokered *(Mmcf)*	11,502	10,793	709	7%
Brokered Natural Gas Revenues *(In thousands)*	$ 93,651	$ 98,605		
Purchase Price *($/Mcf)*	$ 7.25	$ 8.08	$ (0.83)	(10%)
Volume Brokered *(Mmcf)*	11,502	10,793	709	7%
Brokered Natural Gas Cost *(In thousands)*	$ 83,375	$ 87,183		
Brokered Natural Gas Margin *(In thousands)*	$ 10,276	$ 11,422	$ (1,146)	(10%)

(In thousands)	
Sales Price Variance Impact on Revenue	$ (11,434)
Volume Variance Impact on Revenue	6,480
	$ (4,954)

(In thousands)	
Purchase Price Variance Impact on Purchases	$ 9,537
Volume Variance Impact on Purchases	(5,729)
	$ 3,808

The decreased brokered natural gas margin of $1.1 million was driven by a decrease in sales price that outpaced the decrease in purchase cost, offset in part by an increase in volume.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price for 2006 was $65.03 per Bbl. There was no realized impact of crude oil derivative instruments in 2006. Our average total company realized crude oil sales price was $44.19 per Bbl for 2005, including the realized impact of derivative instruments, which reduced the price by $9.93 per Bbl. The following table excludes the unrealized gain from the change in derivative fair value of $5.5 million for the year ended December 31, 2005. There was no unrealized impact from the change in derivative fair value for the year ended December 31, 2006. These unrealized changes in fair value have been included in Crude Oil and Condensate Revenues in the Consolidated Statement of Operations.

	Year Ended December 31,		Variance	
	2006	2005	Amount	Percent
Crude Oil Production *(Mbbl)*				
East	24	27	(3)	(11%)
Gulf Coast	1,160	1,528	(368)	(24%)
West	209	166	43	26%
Canada	12	18	(6)	(33%)
Total Company	1,405	1,739	(334)	(19%)
Crude Oil Sales Price *($/Bbl)*				
East	$ 62.03	$ 53.84	$ 8.19	15%
Gulf Coast	$ 65.44	$ 42.81	$ 22.63	53%
West	$ 63.36	$ 55.37	$ 7.99	14%
Canada	$ 60.55	$ 43.39	$ 17.16	40%
Total Company	$ 65.03	$ 44.19	$ 20.84	47%
Crude Oil Revenue *(In thousands)*				
East	$ 1,474	$ 1,463	$ 11	1%
Gulf Coast	75,894	65,427	10,467	16%
West	13,253	9,155	4,098	45%
Canada	759	791	(32)	(4%)
Total Company	$ 91,380	$ 76,836	$ 14,544	19%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	$ 195			
Gulf Coast	26,242			
West	1,672			
Canada	198			
Total Company	$ 28,307			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	$ (184)			
Gulf Coast	(15,775)			
West	2,426			
Canada	(230)			
Total Company	$ (13,763)			

The increase in the realized crude oil price offset by the decline in production resulted in a net revenue increase of $14.5 million, excluding the unrealized impact of derivative instruments. The decrease in oil production is primarily the result of decreased Gulf Coast production from the 2006 south Louisiana and offshore properties sale in the third quarter of 2006 and the continued natural decline of the CL&F lease in south Louisiana, which was part of the sale. For the year ended December 31, 2006, crude oil and condensate volumes from the properties sold in the third quarter disposition were 707 Mbbls and crude oil and condensate revenues from those properties were approximately $47.4 million.

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,			
	2006		2005	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues - Increase / (Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	$ 28,266	$ —	$ (98,223)	$ 1,114
Crude Oil	—	—	(2,430)	(6)
Total Cash Flow Hedges	28,266	—	(100,653)	1,108
Other Derivative Financial Instruments				
Crude Oil	—	—	(14,842)	5,518
Total Other Derivative Financial Instruments	—	—	(14,842)	5,518
	$ 28,266	$ —	$(115,495)	$ 6,626

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.

Operating Expenses

Total costs and expenses from operations increased by $41.0 million for the year ended December 31, 2006 compared to the year ended December 31, 2005. The primary reasons for this fluctuation were as follows:

- Depreciation, Depletion and Amortization increased by $20.5 million in 2006. This was primarily due to increased production during 2006, an increase in finding costs and an increase in the DD&A rate associated with one field in east Texas as well as the commencement of offshore production in late 2005.
- General and Administrative expense increased by $20.5 million in 2006. This increase was primarily due to increased stock compensation costs of $11.6 million. During 2006, performance share and restricted stock amortization expense increased by $9.6 million and $0.7 million, respectively, primarily due to new grants issued in 2006 and changes in the accounting for the value of performance shares. During 2006, expense related to SARs, which were granted for the first time in 2006, and stock options, which were being expensed in 2006 due to the adoption of SFAS No. 123(R), increased by $1.3 million in total. In addition, there were increases in salaries and incentive compensation related to employee bonuses over the prior year as well as reserves for litigation expenses.
- Exploration expense decreased by $12.4 million in 2006, primarily as a result of decreased dry hole expense of $12.2 million, mainly as a result of a decrease in the Gulf Coast attributable to a more successful drilling program in 2006 compared to 2005 and, to a lesser extent, better success in Canada, partially offset by increased dry hole expense in the West region. In addition, geological and geophysical expenses were down by $1.9 million. Partially offsetting this overall decrease was an increase in employee expenses for salaries and benefits of approximately $1.2 million for employees in the exploration division as well as increased delay rental expenses of $0.6 million.
- Direct Operations expense in 2006 increased by $13.0 million over 2005. This was primarily the result of an increase over the prior year in incentive compensation and personnel related charges, insurance costs, and outside operated properties expense mainly from increases in the Gulf Coast region, largely from repairs related to a plant damaged by the hurricanes that occurred in 2005 and also, to a lesser extent, in the West region. Additional increases occurred in disposal costs, compressor expenses, and treating and pipeline costs. Partially offsetting these increases were decreased workover charges and outside operated plant operations expenses.
- Impairment of Oil and Gas Properties increased by $3.9 million as a result of an impairment recorded in 2006 for a marginally productive gas well in Colorado County, Texas in the Gulf Coast region compared to no impairments of oil and gas properties in 2005. Further analysis of this impairment is discussed in Note 2 of the Notes to the Consolidated Financial Statements.
- Brokered Natural Gas Cost decreased by $3.8 million from 2005 to 2006. See the preceding table labeled "Brokered Natural Gas Revenue and Cost" for further analysis.

Interest Expense, Net

Interest expense, net decreased by $3.4 million due to lower borrowings on our 7.19% fixed rate debt and increased interest on our short term investments as well as the commencement of regulatory interest capitalization on our pipeline in the East region, offset partially by higher average credit facility borrowings as well as an increasing interest rate environment. Weighted-average borrowings based on daily balances were approximately $61 million during 2006 compared to $32 million during 2005. In addition, the weighted-average effective interest rate on the credit facility increased to 7.9% during 2006 from 6.9% during the prior year.

Income Tax Expense

Income tax expense increased by $101.5 million due to a comparable increase in our pre-tax income, primarily as a result of the gain on the sale of assets recorded in the third quarter of 2006. The effective tax rates for 2006 and 2005 were 37.1% and 37.2%, respectively.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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. Under our revolving credit agreement, the aggregate level of commodity hedging must not exceed 100% of the anticipated future equivalent production during the period covered by these cash flow hedges. At December 31, 2007, we had 16 cash flow hedges open: 12 natural gas price collar arrangements, three natural gas swap arrangements and one crude oil price collar arrangement. At December 31, 2007, a $7.3 million ($4.6 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income, along with a $12.7 million short-term derivative receivable and a $5.4 million short-term derivative liability. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives, is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate. During 2007 and 2006, there was no ineffectiveness recorded in the Consolidated Statement of Operations. For 2005, a $6.6 million gain was recorded as a component of revenue, which reflected the ineffective portion of the change in fair value of derivatives designated as hedges and the change in the fair value of all other derivatives.

Assuming no change in commodity prices, after December 31, 2007 we would expect to reclassify to the Consolidated Statement of Operations, over the next 12 months, $4.6 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at December 31, 2007 related to anticipated 2008 production.

Hedges on Production – Swaps

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 2007, we did not enter into any natural gas price swaps covering our 2007 production.

At December 31, 2007, we had open natural gas price swap contracts covering a portion of our 2008 production as follows:

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted-Average Contract Price *(per Mcf)*	Net Unrealized Gain *(In thousands)*
As of December 31, 2007			
First Quarter 2008	1,233	$ 7.44	
Second Quarter 2008	1,233	7.44	
Third Quarter 2008	1,246	7.44	
Fourth Quarter 2008	1,246	7.44	
Full Year 2008	**4,958**	**$ 7.44**	**$ 472**

Hedges on Production – Options

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 2007, natural gas price collars covered 42,533 Mmcf of our gas production, or 53%, of our gas production, with a weighted-average floor of $8.99 per Mcf and a weighted-average ceiling of $12.19 per Mcf.

At December 31, 2007, we had open natural gas price collar contracts covering a portion of our 2008 production as follows:

	Natural Gas Price Collars		
Contract Period	Volume in Mmcf	Weighted-Average Ceiling / Floor *(per Mcf)*	Net Unrealized Gain *(In thousands)*
As of December 31, 2007			
First Quarter 2008	8,523	$10.14 / $8.17	
Second Quarter 2008	8,523	10.14 / 8.17	
Third Quarter 2008	8,617	10.14 / 8.17	
Fourth Quarter 2008	8,617	10.14 / 8.17	
Full Year 2008	**34,280**	**$10.14 / $8.17**	**$ 12,072**

During 2007, an oil price collar covered 365 Mbbls of our crude oil production, or 44%, of our crude oil production, with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

At December 31, 2007, we had one open crude oil price collar contract covering a portion of our 2008 production as follows:

	Crude Oil Price Collars		
Contract Period	Volume in Mbbl	Ceiling / Floor *(per Bbl)*	Net Unrealized Loss *(In thousands)*
As of December 31, 2007			
First Quarter 2008	91	$80.00 / $60.00	
Second Quarter 2008	91	80.00 / 60.00	
Third Quarter 2008	92	80.00 / 60.00	
Fourth Quarter 2008	92	80.00 / 60.00	
Full Year 2008	**366**	**$80.00 / $60.00**	**$ (5,272)**

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. We use available marketing data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" and does not impact our financial position, results of operations or cash flows.

Long-Term Debt

	December 31, 2007		December 31, 2006	
(In thousands)	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Long-Term Debt				
7.19% Notes	$ 40,000	$ 41,376	$ 60,000	$ 61,749
7.26% Notes	75,000	80,066	75,000	80,335
7.36% Notes	75,000	81,259	75,000	82,025
7.46% Notes	20,000	21,799	20,000	22,547
Credit Facility	140,000	140,000	10,000	10,000
Current Maturities				
7.19% Notes	(20,000)	(20,466)	(20,000)	(20,299)
Long-Term Debt, excluding Current Maturities	$ 330,000	$ 344,034	$ 220,000	$ 236,357

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 statments 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007 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, 2007, 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 6 to the consolidated financial statements, effective January 1, 2007, the Company adopted FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109." As discussed in Note 5 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)." As discussed in Notes 1 and 10 to the consolidated financial statements, effective January 1, 2006, the Company adopted Statement of Financial Accounting Standards No. 123(R), "Share Based Payment (revised 2004)."

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.

PricewaterhouseCoopers LLP

Houston, Texas
February 27, 2008

CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
(In thousands, except per share amounts)	**2007**	2006	2005
OPERATING REVENUES			
Natural Gas Production	**$ 581,640**	$ 568,097	$ 499,177
Brokered Natural Gas	**93,215**	93,651	98,605
Crude Oil and Condensate	**55,243**	91,380	82,348
Other	**2,072**	8,860	2,667
	732,170	761,988	682,797
OPERATING EXPENSES			
Brokered Natural Gas Cost	**81,819**	83,375	87,183
Direct Operations - Field and Pipeline	**77,170**	74,790	61,750
Exploration	**39,772**	49,397	61,840
Depreciation, Depletion and Amortization	**143,951**	128,975	108,458
Impairment of Unproved Properties	**19,042**	11,117	12,966
Impairment of Oil & Gas Properties (Note 2)	**4,614**	3,886	—
General and Administrative	**50,775**	58,168	37,650
Taxes Other Than Income	**53,782**	55,351	54,293
	470,925	465,059	424,140
Gain on Sale of Assets	**13,448**	232,017	74
INCOME FROM OPERATIONS	**274,693**	528,946	258,731
Interest Expense and Other	**17,161**	18,441	22,497
Income Before Income Taxes	**257,532**	510,505	236,234
Income Tax Expense	**90,109**	189,330	87,789
NET INCOME	**$ 167,423**	$ 321,175	$ 148,445
Basic Earnings Per Share	**$ 1.73**	$ 3.32	$ 1.52
Diluted Earnings Per Share	**$ 1.71**	$ 3.26	$ 1.49
Weighted Average Common Shares Outstanding	**96,978**	96,803	97,713
Diluted Common Shares (Note 13)	**98,130**	98,601	99,451

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

CONSOLIDATED BALANCE SHEET

(In thousands, except share amounts)	December 31, 2007	2006
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	**$ 18,498**	$ 41,854
Accounts Receivable, Net	**109,306**	116,546
Income Taxes Receivable	**3,832**	24,512
Inventories	**27,353**	32,997
Deferred Income Taxes	**26,456**	9,386
Derivative Contracts (Note 11)	**12,655**	81,982
Other Current Assets	**23,313**	8,405
Total Current Assets	**221,413**	315,682
PROPERTIES AND EQUIPMENT, NET (Successful Efforts Method) (Note 2)	**1,908,117**	1,480,201
DEFERRED INCOME TAXES	**47,847**	30,912
OTHER ASSETS	**31,217**	7,696
	$ 2,208,594	$ 1,834,491
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	**$ 173,497**	$ 147,680
Current Portion of Long-Term Debt	**20,000**	20,000
Deferred Income Taxes	**3,930**	31,962
Income Taxes Payable	**1,391**	9,282
Derivative Contracts (Note 11)	**5,383**	16
Accrued Liabilities	**48,065**	42,087
Total Current Liabilities	**252,266**	251,027
LONG-TERM LIABILITY FOR PENSION BENEFITS (Note 5)	**6,743**	7,219
LONG-TERM LIABILITY FOR POSTRETIREMENT BENEFITS (Note 5)	**20,204**	18,204
LONG-TERM DEBT (Note 4)	**330,000**	220,000
DEFERRED INCOME TAXES	**481,770**	347,430
OTHER LIABILITIES	**47,354**	45,413
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS' EQUITY		
Common Stock:		
Authorized – 120,000,000 Shares of $0.10 Par Value		
Issued and Outstanding – 102,681,468 Shares and		
101,418,220 Shares in 2007 and 2006, respectively	**10,268**	10,142
Additional Paid-in Capital	**424,229**	417,995
Retained Earnings	**722,344**	565,591
Accumulated Other Comprehensive Income / (Loss) (Note 14)	**(894)**	37,160
Less Treasury Stock, at Cost:		
5,204,700 Shares in both 2007 and 2006	**(85,690)**	(85,690)
Total Stockholders' Equity	**1,070,257**	945,198
	$ 2,208,594	$ 1,834,491

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

CONSOLIDATED STATEMENT OF CASH FLOWS

(In thousands)	Year Ended December 31, 2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 167,423**	$ 321,175	$ 148,445
Adjustments to Reconcile Net Income to Cash			
Provided by Operating Activities:			
Depreciation, Depletion and Amortization	**143,951**	128,975	108,458
Impairment of Unproved Properties	**19,042**	11,117	12,966
Impairment of Oil & Gas Properties	**4,614**	3,886	—
Deferred Income Tax Expense	**95,152**	52,011	39,628
Gain on Sale of Assets	**(13,448)**	(232,017)	(74)
Exploration Expense	**39,772**	49,397	61,840
Unrealized Gain on Derivatives	**—**	—	(6,626)
Stock-Based Compensation Expense and Other	**16,241**	21,271	9,803
Changes in Assets and Liabilities:			
Accounts Receivable, Net	**6,854**	39,463	(43,938)
Income Taxes Receivable	**14,456**	(11,198)	1,444
Inventories	**5,644**	(8,381)	(567)
Other Current Assets	**(14,908)**	1,007	1,188
Other Assets	**(29,795)**	(733)	(192)
Accounts Payable and Accrued Liabilities	**1,052**	(29,694)	26,147
Income Taxes Payable	**(1,281)**	18,398	3,656
Other Liabilities	**7,368**	1,912	2,382
Stock-Based Compensation Tax Benefit	**—**	(9,485)	—
Net Cash Provided by Operating Activities	**462,137**	357,104	364,560
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(557,211)**	(467,430)	(351,306)
Proceeds from Sale of Assets	**7,061**	329,474	996
Exploration Expense	**(39,772)**	(49,397)	(61,840)
Net Cash Used in Investing Activities	**(589,922)**	(187,353)	(412,150)
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase in Debt	**175,000**	205,000	265,000
Decrease in Debt	**(65,000)**	(305,000)	(195,000)
Sale of Common Stock Proceeds	**5,099**	6,235	4,586
Stock-Based Compensation Tax Benefit	**—**	9,485	—
Purchase of Treasury Stock	**—**	(46,492)	(19,183)
Dividends Paid	**(10,670)**	(7,751)	(7,213)
Net Cash Provided by / (Used in) Financing Activities	**104,429**	(138,523)	48,190
Net (Decrease) / Increase in Cash and Cash Equivalents	**(23,356)**	31,228	600
Cash and Cash Equivalents, Beginning of Period	**41,854**	10,626	10,026
Cash and Cash Equivalents, End of Period	**$ 18,498**	$ 41,854	$ 10,626

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

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands, except per share amounts)	Common Shares	Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Compre-hensive Income / (Loss)[1]	Retained Earnings	Total
Balance at December 31, 2004	99,362	$ 9,936	2,124	$ (20,015)	$ 375,157	$ (20,351)	$ 110,935	$ 455,662
Net Income							148,445	148,445
Exercise of Stock Options	600	60			4,525			4,585
Purchase of Treasury Stock			904	(19,183)				(19,183)
Tax Benefit of Stock-Based Compensation					3,662			3,662
Stock Amortization and Vesting	202	20			8,997			9,017
Cash Dividends at $0.074 per Share							(7,213)	(7,213)
Other Comprehensive Income						5,236		5,236
Balance at December 31, 2005	100,164	$ 10,016	3,028	$ (39,198)	$ 392,341	$ (15,115)	$ 252,167	$ 600,211
Net Income							321,175	321,175
Exercise of Stock Options	876	88			6,127			6,215
Purchase of Treasury Stock			2,177	(46,492)				(46,492)
Tax Benefit of Stock-Based Compensation					9,485			9,485
Stock Amortization and Vesting	378	38			10,042			10,080
Cash Dividends at $0.08 per Share							(7,751)	(7,751)
Effect of Adoption of SFAS No. 158						(14,079)		(14,079)
Other Comprehensive Income						66,354		66,354
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	644	64			7,503			**7,567**
Stock Held in Rabbi Trust					(6,274)			**(6,274)**
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**

(1) For further details on the components of Accumulated Other Comprehensive Income and Loss, refer to Note 14 of the Notes to the Consolidated Financial Statements.

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

CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME

		Year Ended December 31,		
(In thousands)		**2007**	2006	2005
Net Income		**$ 167,423**	$ 321,175	$ 148,445
Other Comprehensive Income / (Loss), net of taxes				
Reclassification Adjustment for Settled Contracts, net of taxes of $29,801, $10,686 and $(38,404), respectively		**(49,241)**	(17,580)	62,249
Changes in Fair Value of Hedge Positions, net of taxes of $(1,777), $(49,311) and $35,293, respectively		**2,555**	81,679	(57,266)
Defined Benefit Pension and Postretirement Plans:				
Net Loss Arising During the Year, net of taxes of $1,034	**$ (1,733)**			
Amortization of Net Obligation at Transition, net of taxes of $(238)	**394**			
Amortization of Prior Service Cost, net of taxes of $(413)	**681**			
Amortization of Net Loss, net of taxes of $(483)	**799**			
Total Defined Benefit Pension and Postretirement Plans, net of taxes of $(100), $(1,848) and $77, respectively		**141**	3,081	(128)
Foreign Currency Translation Adjustment, net of taxes of $(5,072), $507 and $(427), respectively		**8,491**	(826)	381
Total Other Comprehensive Income / (Loss)		**(38,054)**	66,354	5,236
Comprehensive Income		**$ 129,369**	$ 387,529	$ 153,681

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

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 and Canada. The Company's exploration activities are concentrated in areas with known hydrocarbon resources, which are conducive to multi-well, repeatable drilling programs. The Company's program is designed to be disciplined and balanced with a focus on achieving strong financial returns.

The consolidated financial statements contain the accounts of the Company and its majority-owned subsidiaries after eliminating all significant intercompany balances and transactions. Certain prior year amounts have been reclassified to conform to the current year presentation.

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. The effect on the December 31, 2006 Consolidated Balance Sheet was a reduction to Additional Paid-in Capital and an increase to Common Stock of $5.1 million.

On February 28, 2005, the Company announced that the Board of Directors had declared a 3-for-2 split of the Company's common stock in the form of a stock distribution. The stock dividend was distributed on March 31, 2005 to stockholders of record on March 18, 2005. In lieu of issuing fractional shares, the Company paid cash based on the closing price of the common stock on the record date. All common stock accounts and per share data were retroactively adjusted to give effect to the 3-for-2 split of the Company's common stock.

Recently Issued Accounting Pronouncements

In December 2007, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 160, "Noncontrolling Interest in Consolidated Financial Statements, an amendment of Accounting Research Bulletin (ARB) No. 51." SFAS No. 160 clarifies that a noncontrolling interest (previously commonly referred to as a minority interest) in a subsidiary is an ownership interest in the consolidated entity and should be reported as equity in the consolidated financial statements. The presentation of the consolidated income statement has been changed by SFAS No. 160, and consolidated net income attributable to both the parent and the noncontrolling interest is now required to be reported separately. Previously, net income attributable to the noncontrolling interest was typically reported as an expense or other deduction in arriving at consolidated net income and was often combined with other financial statement amounts. In addition, the ownership interests in subsidiaries held by parties other than the parent must be clearly identified, labeled, and presented in the equity in the consolidated financial statements separately from the parent's equity. Subsequent changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary should be accounted for consistently, and when a subsidiary is deconsolidated, any retained noncontrolling equity interest in the former subsidiary must be initially measured at fair value. Expanded disclosures, including a reconciliation of equity balances of the parent and noncontrolling interest are also required. SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008 and earlier adoption is prohibited. Prospective application is required. At this time, the Company does not have any material noncontrolling interests in consolidated subsidiaries. Therefore, it does not believe that the adoption of SFAS No. 160 will have a material impact on its financial position, results of operations or cash flows.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." SFAS No. 141(R) was issued in an effort to continue the movement toward the greater use of fair values in financial reporting and increased transparency through expanded disclosures. It changes how business acquisitions are accounted for and will impact financial statements at the acquisition date and in subsequent periods. Certain of these changes will introduce more volatility into earnings. The acquirer must now record all assets and liabilities of the acquired business at fair value, and related transaction and restructuring costs will be expensed rather than the previous method of being capitalized as part of the acquisition. SFAS No. 141(R) also impacts the annual goodwill impairment test associated with acquisitions, including those that close before the effective date of SFAS No. 141(R). The definitions of a "business" and a "business combination" have been expanded, resulting in more transactions qualifying as business combinations. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 31, 2008 and earlier adoption is prohibited. The Company cannot predict the impact that the adoption of SFAS No. 141(R) will have on its financial position, results of operations or cash flows with respect to any acquisitions completed after December 31, 2007.

In May 2007, the FASB issued FASB Staff Position (FSP) No. FASB Interpretation Number (FIN) 48-1, "Definition of *Settlement* in FASB Interpretation No. 48," which amends FIN 48 and provides guidance concerning how an entity should determine whether a tax position is "effectively," rather than the previously required "ultimately," settled for the purpose of recognizing previously unrecognized tax benefits. In addition, FSP No. FIN 48-1 provides guidance on determining whether a tax position has been effectively settled. The guidance in FSP No. FIN 48-1 is effective upon the initial January 1, 2007 adoption of FIN 48. Companies that have not applied this guidance must retroactively apply the provisions of this FSP to the date of the initial adoption of FIN 48. The Company has adopted FSP No. FIN 48-1 and no retroactive adjustments were necessary.

In April 2007, the FASB issued FSP No. FIN 39-1, "Amendment of FASB Interpretation No. 39," to amend FIN 39, "Offsetting of Amounts Related to Certain Contracts." The terms "conditional contracts" and "exchange contracts" used in FIN 39 have been replaced with the more general term "derivative contracts." In addition, FSP No. FIN 39-1 permits the offsetting of recognized fair values for the right to reclaim cash collateral or the obligation to return cash collateral against fair values of derivatives under certain circumstances, such as under master netting arrangements. Additional disclosure is also required regarding a company's accounting policy with respect to offsetting fair value amounts. The guidance in FSP No. FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application allowed. The effects of initial adoption should be recognized as a change in accounting principle through retrospective application for all periods presented. The Company does not believe that the adoption of FSP No. FIN 39-1 will have a material impact on its financial position, results of operations or cash flows.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, including an amendment of FASB Statement No. 115," which permits companies to choose, at specified dates, to measure certain eligible financial instruments at fair value. The objective of this Statement is to reduce volatility in preparer reporting that may be caused as a result of measuring related financial assets and liabilities differently and to expand the use of fair value measurements. The provisions of the Statement apply only to entities that elect to use the fair value option and to all entities with available-for-sale and trading securities. Additional disclosures are also required for instruments for which the fair value option is elected. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. No retrospective application is allowed, except for companies that choose to adopt early. At the effective date, companies may elect the fair value option for eligible items that exist at that date, and the effect of the first remeasurement to fair value must be reported as a cumulative-effect adjustment to the opening balance of retained earnings. Since the Company has not elected to adopt the fair value option for eligible items, it does not believe that SFAS No. 159 will have an impact on its financial position or results of operations.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which establishes a formal framework for measuring fair values of assets and liabilities in financial statements that are already required by United States generally accepted accounting principles (GAAP) to be measured at fair value. SFAS No. 157 clarifies guidance in FASB Concepts Statement (CON) No. 7 which discusses present value techniques in measuring fair value. Additional disclosures are also required for transactions measured at fair value. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. In November 2007, the FASB granted a one year deferral (to fiscal years beginning after November 15, 2008) for non-financial assets and liabilities to comply with SFAS No. 157. The Company does not believe that SFAS No. 157 will have a material impact on its financial position or results of operations.

Inventories

Inventories are comprised of natural gas and, to a lesser extent, oil in storage, tubular goods and well equipment and pipeline imbalances. All inventory balances are carried at the lower of cost or market. Natural gas and oil in storage are 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 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 the annual review of all fields. The impairment of unamortized capital costs is measured at a lease level and is reduced to fair value if it is determined that the sum of expected future net cash flows is less than the net book value. During 2007 and 2006, the Company recorded total impairments of $4.6 million and $3.9 million, respectively. During 2005, the Company did not record any impairments.

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 offshore portfolio and certain south Louisiana properties to a third party, which was substantially completed in 2006 (the 2006 south Louisiana and offshore properties sale).

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.

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 $11.4 million, $10.3 million and $11.4 million of brokered natural gas margin in 2007, 2006 and 2005, 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.

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.

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, 2007 and 2006 as sufficient cash was available for offset.

Allowance for Doubtful Accounts

The Company records an allowance for doubtful accounts for receivables that the Company feels may 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 $4.0 million and $4.6 million at December 31, 2007 and 2006, respectively.

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, 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

Effective January 1, 2006, the Company adopted the provisions of SFAS No. 123(R), "Share Based Payment (revised 2004)," which replaces the provisions of Accounting Principles Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees" and SFAS No. 123, "Accounting for Stock-Based Compensation," (as amended). The Company elected the modified prospective transition method for adoption, and accordingly, no adjustments to prior period financial statements were made. Upon adoption, the Company recorded a cumulative effect charge totaling $0.6 million ($0.4 million, net of tax), which is included within General and Administrative Expenses in the Consolidated Statement of Operations due to its immateriality. Adoption of SFAS No. 123(R) increased income from operations and income before income taxes by approximately $1.3 million and increased net income by approximately $0.8 million for the year ended December 31, 2006. In addition, the tax benefit for stock-based compensation of $9.5 million for 2006 is now included as both a cash inflow from financing activities and a cash outflow from operating activities in the Consolidated Statement of Cash Flows. 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 under the Alternative Minimum Tax system. See Note 10 of the Notes to the Consolidated Financial Statements for additional details.

Prior to January 1, 2006, the Company accounted for stock-based compensation in accordance with the intrinsic value based method prescribed by APB No. 25. Under the intrinsic value based method, no compensation expense was recorded for stock options granted when the exercise price for options granted was equal to or greater than the fair value of the Company's common stock on the date of the grant. See Note 10 of the Notes to the Consolidated Financial Statements for additional disclosure.

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. At December 31, 2007 and 2006, the cash and cash equivalents are primarily concentrated in two financial institutions. The Company periodically assesses the financial condition of these institutions and believes that any possible credit risk is minimal.

Excluded from cash and cash equivalents at December 31, 2007 is $11.6 million of restricted cash. See Note 7 of the Notes to the Consolidated Financial Statements for further details.

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:

	December 31,	
(In thousands)	**2007**	2006
Unproved Oil and Gas Properties	**$ 108,868**	$ 114,108
Proved Oil and Gas Properties	**2,627,346**	2,109,045
Gathering and Pipeline Systems	**235,127**	205,473
Land, Building and Improvements	**5,094**	4,976
Other	**36,508**	34,067
	3,012,943	2,467,669
Accumulated Depreciation, Depletion and Amortization	**(1,104,826)**	(987,468)
	$ 1,908,117	$ 1,480,201

On January 1, 2005, the Company adopted FSP FAS 19-1, "Accounting for Suspended Well Costs." Upon adoption of the FSP, the Company evaluated all existing capitalized exploratory well costs under the provisions of the FSP. The provisions 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 has been 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 2007, 2006 and 2005.

	December 31,		
(In thousands)	**2007**	2006	2005
Beginning balance at January 1	**$ 8,428**	$ 6,132	$ 8,591
Additions to capitalized exploratory well costs pending the determination of proved reserves	**2,161**	8,317	6,132
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(8,011)**	(5,926)	(1,069)
Capitalized exploratory well costs charged to expense	**(417)**	(95)	(7,522)
Ending balance at December 31	**$ 2,161**	$ 8,428	$ 6,132

At December 31, 2007 and 2005, the Company did not have any projects that had exploratory well costs that were capitalized for a period of greater than one year. At December 31, 2006, the Company had four projects that had exploratory well costs that were capitalized for a period greater than one year.

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:

	December 31,		
(In thousands)	**2007**	2006	2005
Capitalized exploratory well costs that have been capitalized for a period of one year or less	**$ 2,161**	$ 8,317	$ 6,132
Capitalized exploratory well costs that have been capitalized for a period greater than one year	**—**	111	—
Balance at December 31	**$ 2,161**	$ 8,428	$ 6,132
Number of projects that have exploratory well costs that have been capitalized for a period greater than one year	**—**	4	—

At December 31, 2006, the Company had two wells where the drilling was complete, but a determination of whether proved reserves existed could not be made. Costs associated with these wells have been capitalized for less than one year. One well, located in Canada, completed drilling in September 2006. Subsequent well completion attempts were halted until mid-November 2006, waiting for acceptable weather conditions. The well was completed in the first quarter of 2007. The second well is in the Rocky Mountains area and reached total depth in November 2006. Completion attempts were postponed due to the Bureau of Land Management stipulation which prohibits activity until the summer of 2007. Subsequent completion attempts proved unsuccessful and the costs were expensed in the second quarter of 2007.

Included in the December 31, 2006 amount of exploratory well costs that have been capitalized for a period greater than one year are $0.1 million of costs that have been capitalized since 2005. This amount relates to three projects comprised of preliminary costs incurred in the preparation of well sites where drilling has not commenced as of December 31, 2006. In 2007, it was determined not to drill these projects and associated costs were expensed. Also included in the December 31, 2006 amount was another well that had completed drilling in January 2007 and was awaiting completion results before confirmation of proved reserves could be made. That well was completed in 2007 and proved reserves were recorded in the first quarter of 2007.

At December 31, 2007 and 2005, the Company had no wells that had completed drilling for more than one year where a determination of whether proved reserves existed could not be made.

During 2007, the Company recorded an impairment of approximately $4.6 million in the Castor field in Bienville Parish, Louisiana in the Gulf Coast region resulting from two non-commercial development completions. During 2006, the Company recorded an impairment of $3.9 million. The impairment was recorded on a marginally productive gas well in Colorado County, Texas in the Gulf Coast region. Both the 2007 and 2006 impairment charges were recorded due to the capitalized costs of the fields exceeding the future undiscounted cash flows. These charges were reflected in the operating results of the Company and were measured based on discounted cash flows utilizing a discount rate appropriate for risks associated with the related field. During 2005, the Company did not record any impairments.

Disposition of Assets

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 received in the first quarter of 2007, $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:

	December 31,	
(In thousands)	**2007**	2006
ACCOUNTS RECEIVABLE, NET		
Trade Accounts	**$ 94,550**	$ 102,023
Joint Interest Accounts	**16,443**	18,574
Other Accounts	**2,291**	501
	113,284	121,098
Allowance for Doubtful Accounts	**(3,978)**	(4,552)
	$ 109,306	$ 116,546
INVENTORIES		
Natural Gas and Oil in Storage	**$ 20,472**	$ 22,717
Tubular Goods and Well Equipment	**5,953**	7,680
Pipeline Imbalances	**928**	2,600
	$ 27,353	$ 32,997
OTHER CURRENT ASSETS		
Drilling Advances	**$ 2,475**	$ 651
Prepaid Balances	**8,900**	7,416
Restricted Cash	**11,600**	—
Other Accounts	**338**	338
	$ 23,313	$ 8,405
OTHER ASSETS		
Note Receivable	**$ 13,375**	$ —
Rabbi Trust Deferred Compensation Plan	**9,744**	6,077
Other Accounts	**8,098**	1,619
	$ 31,217	$ 7,696
ACCOUNTS PAYABLE		
Trade Accounts	**$ 27,678**	$ 28,569
Natural Gas Purchases	**6,465**	8,356
Royalty and Other Owners	**37,023**	37,230
Capital Costs	**83,754**	59,524
Taxes Other Than Income	**6,416**	4,805
Drilling Advances	**1,528**	1,506
Wellhead Gas Imbalances	**3,227**	2,288
Other Accounts	**7,406**	5,402
	$ 173,497	$ 147,680
ACCRUED LIABILITIES		
Employee Benefits	**$ 13,699**	$ 13,575
Current Liability for Pension Benefits	**116**	67
Current Liability for Postretirement Benefits	**642**	577
Taxes Other Than Income	**13,216**	15,696
Interest Payable	**6,518**	5,995
Litigation	**11,600**	—
Other Accounts	**2,274**	6,193
	$ 48,065	$ 42,103
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$ 16,018**	$ 6,077
Accrued Plugging and Abandonment Liability	**24,724**	22,655
Other Accounts	**6,612**	16,681
	$ 47,354	$ 45,413

4. Debt and Credit Agreements

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 offering. The 7.19% Notes require five annual $20 million principal payments which started in November 2005. The Company made the required $20 million payments in 2007, 2006 and 2005. The Company may prepay all or any portion of the indebtedness on any date with a prepayment penalty. The 7.19% 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. These covenants include a required asset coverage ratio (present value of proved reserves to debt and other liabilities) that must be 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.

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 transaction. Prior to the determination of the Note's 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. All of 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 Notes were issued under the same Note Purchase Agreement as the 7.19% Notes.

Revolving Credit Agreement

On December 10, 2004, the Company amended its Revolving Credit Agreement (credit facility) with a group of nine banks. The credit facility allows for borrowings of $250 million, of which $140 million and $10 million were outstanding at December 31, 2007 and 2006, respectively. The credit facility can be expanded up to $350 million, either with the existing banks or new banks. The credit facility is unsecured. The term of the credit facility expires in December 2009. The available credit line is subject to adjustment from time to time on the basis of the projected present value (as determined by the banks' petroleum engineer) of estimated future net cash flows from certain proved oil and gas reserves and other assets of the Company. 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, the Company has a period of six months either to reduce its outstanding debt to the adjusted credit line available with a requirement to provide additional borrowing base assets or to pay down one-sixth of the excess during each of the six months.

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 is 50% or greater, greater than 75% or greater than 90% of the Company's debt limit of $610 million, as shown below:

	Debt Percentage			
	Lower than 50%	50% or higher but not exceeding 75%	Higher than 75% but not exceeding 90%	Higher than 90%
Euro-Dollar margin	1.000%	1.250%	1.500%	1.750%
Base Rate margin	0.000%	0.000%	0.250%	0.500%

The Company's weighted-average effective interest rates for the credit facility during the years ended December 31, 2007, 2006 and 2005 were 7.2%, 7.9% and 6.9%, respectively. As of December 31, 2007, the weighted-average interest rate on the Company's credit facility was 6.9%. The credit facility provides for a commitment fee on the unused available balance at an annual rate of one-quarter of 1%. The credit facility also contains various customary restrictions, which include the following:

(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) 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.

The Company believes it was in compliance in all material respects with its covenants contained in its various debt agreements at December 31, 2007 and 2006 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)	**2007**	2006	2005
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 45,475**	$ 41,211	$ 36,066
Service Cost	**2,931**	2,720	1,803
Interest Cost	**2,769**	2,333	1,981
Actuarial Loss	**1,314**	5	1,852
Plan Amendments	**—**	(3)	120
Benefits Paid	**(886)**	(791)	(611)
Benefit Obligation at End of Year	**51,603**	45,475	41,211
Change in Plan Assets			
Fair Value of Plan Assets at Beginning of Year	**38,189**	23,765	18,092
Actual Return on Plan Assets	**3,179**	3,587	1,544
Employer Contributions	**5,000**	12,008	5,000
Benefits Paid	**(886)**	(791)	(611)
Expenses Paid	**(738)**	(380)	(260)
Fair Value of Plan Assets at End of Year	**44,744**	38,189	23,765
Funded Status at End of Year	**$ (6,859)**	$ (7,286)	$ (17,446)

Amounts Recognized in the Balance Sheet

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

(In thousands)	**2007**	2006	2005
Long-Term Assets	**$ —**	$ —	$ 454
Current Liabilities	**(116)**	(67)	(1,204)
Long-Term Liabilities	**(6,743)**	(7,219)	(5,904)
	$ (6,859)	$ (7,286)	$ (6,654)

Amounts Recognized in Accumulated Other Comprehensive Income

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

(In thousands)	2007	2006	2005
Prior Service Cost	**$ 194**	$ 336	$ —
Net Actuarial Loss	**13,744**	12,946	—
Minimum Pension Liability	**—**	—	(5,119)
	$ 13,938	$ 13,282	$ (5,119)

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 approximately $0.1 million and $0.8 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 $0.1 million, respectively.

The combined accumulated benefit obligation for both pension plans was $39.5 million, $34.8 million and $30.9 million at December 31, 2007, 2006 and 2005, respectively.

Components of Net Periodic Benefit Cost and Other Amounts Recognized in Other Comprehensive Income

Qualified Pension Plan

(In thousands)	2007	2006	2005
Qualified Components of Net Periodic Benefit Cost			
Current Year Service Cost	**$ 2,705**	$ 2,518	$ 2,485
Interest Cost	**2,611**	2,211	1,896
Expected Return on Plan Assets	**(3,015)**	(1,962)	(1,507)
Amortization of Prior Service Cost	**84**	98	99
Amortization of Net Loss	**987**	1,125	921
Net Periodic Pension Cost	**$ 3,372**	$ 3,990	$ 3,894
Other Changes in Qualified Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income			
Net Loss	**1,694**	N/A	N/A
Amortization of Net Loss	**(987)**	N/A	N/A
Amortization of Prior Service Cost	**(84)**	N/A	N/A
Total Recognized in Other Comprehensive Income	**623**	N/A	N/A
Total Recognized in Qualified Net Periodic Benefit Cost and Other Comprehensive Income	**$ 3,995**	N/A	N/A

Non-Qualified Pension Plan

(In thousands)	2007	2006	2005
Non-Qualified Components of Net Periodic Benefit Cost			
Current Year Service Cost	$ 226	$ 203	$ (682)
Interest Cost	158	122	85
Amortization of Prior Service Cost	58	77	77
Amortization of Net Loss / (Gain)	102	85	(22)
Net Periodic Pension Cost / (Income)	$ 544	$ 487	$ (542)
Other Changes in Non-Qualified Benefit Obligations Recognized in Other Comprehensive Income			
Net Loss	193	N/A	N/A
Amortization of Net Loss	(102)	N/A	N/A
Amortization of Prior Service Cost	(58)	N/A	N/A
Total Recognized in Other Comprehensive Income	33	N/A	N/A
Total Recognized in Non-Qualified Net Periodic Benefit Cost and Other Comprehensive Income	$ 577	N/A	N/A

Assumptions

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

	2007	2006	2005
Discount Rate	6.00%	5.75%	5.50%
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:

	2007	2006	2005
Discount Rate	5.75%	5.50%	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 2007, as shown above, is eight percent. 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 2007, 2006 and 2005. 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 16 years. This model uses historical data for the period of 1926-2003 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 percent of the time, is approximately nine percent. The Company expects to achieve a minimum 6.4% annual real rate of return on the total portfolio over the long-term at least 75 percent of the time. In addition, the actual rate of return on plan assets annualized over the past ten years is approximately six percent. The Company believes that the eight percent chosen is a reasonable estimate based on its actual results.

Plan Assets

At December 31, 2007 and 2006, the non-qualified pension plan did not have plan assets. The plan assets of the Company's qualified pension plan at December 31, 2007 and 2006, by asset category are as follows:

	2007		2006	
(In thousands)	Amount	Percent	Amount	Percent
Equity securities	$ 31,220	70%	$ 27,124	71%
Debt securities	12,684	28%	10,605	28%
Other [1]	840	2%	460	1%
Total	$ 44,744	100%	$ 38,189	100%

(1) *Primarily consists of cash and cash equivalents.*

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 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.

Cash Flows

Contributions

The funding levels of the pension plans are in compliance with standards set by applicable law or regulation. In 2007, the Company did not have any required minimum funding obligations; however, it chose to fund $5 million into the qualified plan. In 2008, the Company does not have any required minimum funding obligations for the qualified pension plan. The Company will contribute $0.1 million, as shown below, for the non-qualified pension plan. Currently, management has not determined if any discretionary funding will be made in 2008.

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
2008	$ 1,075	$ 127	$ 1,202
2009	1,337	171	1,508
2010	1,395	298	1,693
2011	1,613	217	1,830
2012	2,052	342	2,394
Years 2013 - 2017	16,118	2,158	18,276

POSTRETIREMENT BENEFITS OTHER THAN PENSIONS

In addition to providing pension benefits, the Company provides certain health care and life insurance 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. The life insurance plans were non-contributory. As of January 1, 2006, the Company no longer provides postretirement life insurance coverage. Most employees become eligible for these benefits if they meet certain age and service requirements at retirement. The Company was providing postretirement benefits to 235 retirees and their dependants at the end of 2007 and 244 retirees and their dependants at the end of 2006.

When the Company adopted SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pension", 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 the adoption of SFAS No. 158, 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 projected 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 projected 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)	**2007**	2006	2005
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 18,781**	$ 11,793	$ 14,101
Service Cost	**871**	789	675
Interest Cost	**1,076**	877	605
Actuarial Loss / (Gain)	**880**	6,337	(876)
Plan Amendments	**—**	(153)	(1,434)
Benefits Paid	**(762)**	(862)	(1,278)
Benefit Obligation at End of Year	**20,846**	18,781	11,793
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	**$ (20,846)**	$ (18,781)	$ (11,793)

Amounts Recognized in the Balance Sheet

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

(In thousands)	**2007**	2006	2005
Current Liabilities	**$ (642)**	$ (577)	$ (500)
Long-Term Liabilities	**(20,204)**	(18,204)	(6,514)
	$ (20,846)	$ (18,781)	$ (7,014)

Amounts Recognized in Accumulated Other Comprehensive Income

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

(In thousands)	**2007**	2006	2005
Transition Obligation	**$ 2,527**	$ 3,159	N/A
Prior Service Cost	**1,618**	2,570	N/A
Net Actuarial Loss	**4,392**	3,705	N/A
	$ 8,537	$ 9,434	N/A

The estimated net obligation at transition, prior service cost 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, $1.0 million and $0.2 million, respectively.

Components of Net Periodic Benefit Cost

(In thousands)	**2007**	2006	2005
Components of Net Periodic Postretirement Benefit Cost			
Current Year Service Cost	**$ 871**	$ 789	$ 675
Interest Cost	**1,076**	877	605
Amortization of Prior Service Cost	**952**	952	910
Amortization of Net Obligation at Transition	**632**	632	648
Amortization of Net Loss / (Gain)	**193**	32	(79)
SFAS 106 Net Periodic Postretirement Cost	**3,724**	3,282	2,759
Recognized Curtailment Gain	**—**	(86)	—
Recognized Loss Due to Special Term Benefits	**—**	—	319
SFAS 88 (Cost) / Income	**—**	(86)	319
Total SFAS 106 and SFAS 88 Cost	**$ 3,724**	$ 3,196	$ 3,078
Other Changes in Benefit Obligations Recognized in Other Comprehensive Income			
Net Loss	**880**	N/A	N/A
Amortization of Prior Service Cost	**(952)**	N/A	N/A
Amortization of Net Obligation at Transition	**(632)**	N/A	N/A
Amortization of Net Loss / (Gain)	**(193)**	N/A	N/A
Total Recognized in Other Comprehensive Income	**(897)**	N/A	N/A
Total Recognized in Qualified Net Periodic Benefit Cost and Other Comprehensive Income	**$ 2,827**	N/A	N/A

Assumptions

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

	2007	2006	2005
Discount Rate (1)	**6.00%**	5.75%	5.50%
Health Care Cost Trend Rate for Medical Benefits Assumed for Next Year	**9.00%**	8.00%	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	**2012**	2010	2010

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2007, 2006 and 2005, respectively, the beginning of year discount rates of 5.75%, 5.5% and 5.75% were used.

The health care cost trend rate used to measure the expected cost from 2000 to 2003 for medical benefits to retirees was eight percent. Provisions of the plan existing at that time would have prevented significant future increases in employer cost after 2000. During the years ended December 31, 2005 and 2004, the plan was amended in several areas effective January 1, 2006. As of January 1, 2006, coverage provided to participants age 65 and older is under a fully-insured arrangement which replaces the former self-funded plan. Benefits under this new arrangement are comparable to benefits under the self-funded plan. 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 will increase by 3.5% annually thereafter. Additionally, in February 2005, the Company prepaid the life insurance premiums for all retirees retiring before January 1, 2006, eliminating all future premiums for retiree life insurance. Effective January 1, 2006, the Company eliminated company paid retiree life insurance coverage. Changes were made to the life insurance product that 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	$ 382	$ (306)
Effect on postretirement benefit obligation	3,403	(2,770)

Cash Flows

Contributions

The Company expects to contribute approximately $0.7 million to the postretirement benefit plan in 2008.

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)	
2008	$ 661
2009	706
2010	761
2011	831
2012	917
Years 2013 - 2017	6,446

On December 8, 2003, the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the Act) was signed into law. 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 FSP No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", 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, FSP No. 106-2 did not have an impact on operating results, financial position or cash flows of the Company.

Incremental Effect of Applying SFAS No. 158 to Pension and Postretirement Plans on Individual Line Items in the Balance Sheet

The table below illustrates the incremental effects of applying SFAS No. 158 to various individual balance sheet line items as of December 31, 2006. The column entitled "Before Application of SFAS No. 158" includes the effect of the additional minimum liability adjustment required for 2006.

(In thousands)	Before Application of SFAS No. 158	Adjustments	After Application of SFAS No. 158
Other Assets	$ 7,864	$ (168)	$ 7,696
Deferred Income Tax Asset (Non-Current)	22,465	8,447	30,912
Total Assets	1,826,212	8,279	1,834,491
Accrued Liabilities	41,459	644	42,103
Total Current Liabilities	250,383	644	251,027
Long-Term Liability for Pension Benefits	(5,639)	12,858	7,219
Long-Term Liability for Postretirement Benefits	9,348	8,856	18,204
Accumulated Other Comprehensive Income	51,239	(14,079)	37,160
Total Stockholders' Equity	959,277	(14,079)	945,198
Total Liabilities and Stockholders' Equity	1,826,212	8,279	1,834,491

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 $2.0 million, $1.8 million and $1.6 million in 2007, 2006, and 2005, 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 employee's base salary and bonus deferrals cause the employee 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 employee 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 quoted and 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 $9.7 million and $6.1 million at December 31, 2007 and 2006, respectively, and is included within Other Assets in the Consolidated Balance Sheet. Related liabilities totaled $16.0 million and $6.1 million at December 31, 2007 and 2006 respectively, and are included within Other Liabilities in the Consolidated Balance Sheet. The Company's common stock held in the rabbi trust is recorded at the market value on the date of deferral, which totalled $6.3 million at December 31, 2007 and is included within Additional Paid-in Capital in Stockholder's Equity in the Consolidated Balance Sheet. There was no common stock held in the trust in 2006. The Company 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.

There is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets, excluding the Company's common stock, 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. Stock compensation expense may be recognized if the fair market value of the Company common stock changes. This impact was immaterial in 2007.

The Company charged to expense plan contributions of less than $20,000 in each of 2007, 2006 and 2005.

6. Income Taxes

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
(In thousands)	**2007**	2006	2005
Current			
Federal	**$ (1,424)**	$ 123,155	$ 42,976
State	**(3,619)**	14,164	5,185
Total	**(5,043)**	137,319	48,161
Deferred			
Federal	**91,257**	49,911	37,565
State	**3,895**	2,100	2,063
Total	**95,152**	52,011	39,628
Total Income Tax Expense	**$ 90,109**	$ 189,330	$ 87,789

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

(In thousands)	Year Ended December 31, 2007	2006	2005
Statutory Federal Income Tax Rate	**35%**	35%	35%
Computed "Expected" Federal Income Tax	**$ 90,137**	$ 178,818	$ 82,682
State Income Tax, Net of Federal Income Tax Benefit	**5,452**	14,494	7,030
Qualified Production Activities Deduction	**—**	(2,327)	(1,324)
Benefit Related to Favorable State Tax Determination (1)	**(2,831)**	—	—
Deferred Tax Benefit Related to Reduction in Overall State Tax Rate (2)	**(1,378)**	(2,605)	(550)
Other, Net	**(1,271)**	950	(49)
Total Income Tax Expense	**$ 90,109**	$ 189,330	$ 87,789

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

(2) Adjustment primarily due to the 2006 south Louisiana and offshore properties sale.

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, 2007	2006
Deferred Tax Liabilities		
Property, Plant and Equipment	**$ 472,444**	$ 346,198
Items Accrued for Financial Reporting Purposes	**5,395**	2,408
Other Comprehensive Income	**7,861**	30,786
Total	**485,700**	379,392
Deferred Tax Assets		
Alternative Minimum Tax Credit Carryforwards	**8,587**	—
Net Operating Loss Carryforwards	**22,170**	1,281
Items Accrued for Financial Reporting Purposes	**35,193**	30,564
Other Comprehensive Income	**8,353**	8,453
Total	**74,303**	40,298
Net Deferred Tax Liabilities	**$ 411,397**	$ 339,094

As of December 31, 2007, the Company had incurred net operating losses for regular income tax reporting purposes of $49.8 million that it expects to utilize against 2005 taxable income. In addition, the Company had alternative minimum tax credit carryforwards of $8.6 million which 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 $82.3 million for state income tax reporting purposes, the majority of which will expire between 2016 and 2027. It is expected that these deferred tax benefits will be utilized prior to their expiration.

UNCERTAIN TAX POSITIONS

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes - an Interpretation of FASB Statement No. 109." This Interpretation provides guidance for recognizing and measuring uncertain tax positions as defined in SFAS No. 109, "Accounting for Income Taxes." FIN 48 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. If the recognition threshold is met, FIN 48 provides additional guidance on measuring the amount of the uncertain tax position. Under FIN 48, 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. 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 position. FIN 48 is effective for fiscal years beginning after December 15, 2006.

The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized no 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 January 1, 2007, the Company had recorded a liability of approximately $0.9 million for interest. During 2007, the Company reversed this liability and recorded interest receivable of $0.4 million. This resulted in an adjustment to net interest expense of $1.3 million. As of December 31, 2007, the Company determined that no accrual for penalties was required.

As of January 1, 2007, after the implementation of FIN 48, the Company's unrecognized tax benefits were $1.0 million. This amount, if recognized, would not affect the effective tax rate. As of December 31, 2007, it is reasonably possible that the 2001-2004 years currently pending before the IRS Appeals Division will be settled within the next twelve months. Discussions are ongoing with the taxing authorities regarding these years. The amounts recorded reflect the Company's estimate as to the ultimate resolution of these matters. For the year ended December 31, 2007, the unrecognized tax benefit increased by $1.4 million. The amount of unrecognized tax benefits, 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:

(In thousands)	
Unrecognized tax benefit balance at January 1, 2007	$ 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	(19)
Settlements	—
Unrecognized tax benefit balance at December 31, 2007	**$ 2,425**

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 U.S. federal statute of limitations remains open for years 2001 and onward. State income tax returns are generally subject to examination for a period of three to four years after filing of the respective return. The state impact of any federal changes remains subject to examination by various states for a period of up to one year after formal notification to the states. Years still open to examination by state authorities in major jurisdictions include Texas and West Virginia (2001 onward). The Company is not currently under examination, nor has it been notified of an upcoming examination, by West Virginia. The Company has been audited by Texas for report years through 2006. The audits were resolved successfully and no material adjustments were made.

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 Canada, the West and East regions. 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.

Future obligations under firm gas transportation agreements in effect at December 31, 2007 are as follows:

(In thousands)	
2008	$ 9,937
2009	10,156
2010	6,703
2011	4,526
2012	3,350
Thereafter	47,493
	$ 82,165

Drilling Rig Commitments

The Company has five drilling rigs in the Gulf Coast that are under contract. As of December 31, 2007, the Company is obligated under these contracts to pay $71.3 million over the next three years as follows:

(In thousands)	
2008	$ 41,180
2009	27,902
2010	2,250
	$ 71,332

Lease Commitments

The Company leases certain transportation vehicles, warehouse facilities, office space, and machinery and equipment under cancelable and non-cancelable leases. The lease for the Company's office in Houston runs for approximately two more years. All of these operating leases expire within the next five years, and some of these leases may be renewed. Rent expense under such arrangements totaled $12.3 million, $10.7 million and $9.1 million for the years ended December 31, 2007, 2006 and 2005, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2007 are as follows:

(In thousands)	
2008	$ 5,414
2009	4,120
2010	1,267
2011	528
2012	183
Thereafter	—
	$ 11,512

Guarantees

During 2006, the Company assisted certain non-executive employees in obtaining loans to purchase interests offered under its Mineral, Royalty and Overriding Royalty Interest Plan by providing a guarantee of repayment should the non-executive employee fail to repay the loan. The repayment term for all of these loans was five years. The outstanding loan balances were approximately $0.3 million in the aggregate as of December 31, 2006 and the fair value of these guarantees were immaterial to the Company's financial statements. There were no outstanding loan balances as of December 31, 2007. All loans were collateralized by the interests transferred to the employees in the producing properties.

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.

West Virginia Royalty Litigation. In December 2001, the Company was sued by two royalty owners in West Virginia state court for an unspecified amount of damages. The plaintiffs requested class certification and alleged that the Company failed to pay royalty based upon the wholesale market value of the gas, that the Company had taken improper deductions from the royalty and that it failed to properly inform royalty owners of the deductions. The plaintiffs also claimed that they are entitled to a 1/8th royalty share of the gas sales contract settlement that the Company reached with Columbia Gas Transmission Corporation in 1995 bankruptcy proceedings. The Court entered an order on June 1, 2005 granting the motion for class certification.

The parties reached a tentative settlement in 2007 pursuant to which the Company paid $11.6 million into a trust fund which will disburse the settlement proceeds to the class members upon final approval of the settlement by the Court . These restricted cash funds are held by a financial institution in West Virginia under the joint custody of the plaintiffs and the Company. These funds have been classified within Other Current Assets in the Consolidated Balance Sheet. Subsequent to reaching the tentative settlement, it was determined that an additional payment of $0.4 million would be required to account for production from new wells that came on-line during the process of settlement negotiations and were not included in the volumes upon which the $11.6 million settlement was reached. The additional funds bring the total to be paid by the Company to $12.0 million.

In the tentative settlement, the Company and the class members also agreed to a methodology for payment of future royalties and the reporting format such methodology will take. The tentative settlement was not to be final or binding until approved by the Court. The hearing for final approval of the settlement was held on February 12, 2008. The Court approved the final settlement at the hearing. Upon filing of the written Order of Approval by the Court, the process will begin for distribution of the settlement proceeds from the trust. The Company had provided a reserve sufficient to cover the amount agreed upon to settle this litigation.

Commitment and Contingency Reserves. The Company has established 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 $8.4 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.

8. Cash Flow Information

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

	Year Ended December 31,		
(In thousands)	**2007**	2006	2005
Interest	**$ 20,257**	$ 24,088	$ 17,366
Income Taxes	**(20,099)**	128,752	47,142

The decrease in cash paid for income taxes from 2006 to 2007 is primarily due to the Company's 2007 net operating loss position and the receipt of $29.6 million in federal tax refunds relating to the Company's 2006 tax return. The increase in cash paid for income taxes from 2005 to 2006 is primarily due to the December 2006 payment of approximately $102 million related to the sale of the Company's offshore and certain south Louisiana assets.

The Company recorded benefits of $9.5 million and $3.7 million for the years ended December 31, 2006 and 2005, respectively, for tax deductions taken due to employee stock option exercises and restricted stock grant vesting. 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 under the Alternative Minimum Tax system. See Note 10 of the Notes to the Consolidated Financial Statements for additional details.

9. Capital Stock

Incentive Plans

On April 29, 2004, the 2004 Incentive Plan was approved by the shareholders. 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 15,000 shares (pre 2-for-1 split) of common stock on the date the non-employee directors first join the Board of Directors. In its place, the Board of Directors will consider 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. Awards outstanding under the Company's prior stock plans will remain outstanding in accordance with their original terms and conditions.

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

On May 4, 2006, the stockholders of the Company approved an increase in the authorized number of shares of common stock from 80 million to 120 million shares. The Company correspondingly increased the number of shares of Series A Junior Participating Preferred Stock reserved for issuance from 800,000 to 1,200,000. The shares of Series A Junior Participating Preferred Stock are issuable pursuant to the Preferred Stock Purchase Rights Plan described below.

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, 2007, the Company did not repurchase any shares of common stock. Since the authorization date, the Company has repurchased 5,204,700 shares, or 52% of the 10 million total shares authorized for repurchase at December 31, 2007, for a total cost of approximately $85.7 million. The repurchased shares are held as treasury stock. No treasury shares have been delivered or sold by the Company subsequent to the repurchase.

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.

Purchase Rights

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. Each right becomes exercisable when any person or group has acquired or made a tender or exchange offer for beneficial ownership of 15% or more of the Company's outstanding common stock. Each right entitles the holder, other than the acquiring person or group, to purchase a fraction of a share of Series A Junior Participating Preferred Stock (Junior Preferred Stock). After a person or group acquires beneficial ownership of 15% of the common stock, each right entitles the holder to purchase common stock or other property having a market value (as defined in the plan) of twice the exercise price of the right. An exception to this triggering event applies in the case of a tender or exchange offer for all outstanding shares of common stock determined to be fair and in the best interests of the Company and its stockholders by a majority of the independent directors. Under certain circumstances, the Board of Directors may opt to exchange one share of common stock for each exercisable right. If there is a 15% holder and the Company is acquired in a merger or other business combination in which it is not the survivor, or 50% or more of the Company's assets or earning power are sold or transferred, each right entitles the holder to purchase common stock of the acquiring company with a market value (as defined in the plan) equal to twice the exercise price of each right. At December 31, 2007 there were no shares of Junior Preferred Stock issued or outstanding.

The rights expire on January 21, 2010, and may be redeemed by the Company at any time before a person or group acquires beneficial ownership of 15% of the common stock.

As a result of stock splits in 2005 and 2007, each share of common stock continues to include one right under the Company's Preferred Stock Purchase Rights Plan, and each right now provides for the purchase, upon the occurrence of the conditions set forth in the plan, of one-third of one one-hundredth of a share of preferred stock at a purchase price of approximately $18.33 per one-third of one one-hundredth of a share (or $55 for each one one-hundredth of a share). The redemption price of each right is now one-third of a cent.

10. Stock-Based Compensation

Adoption of SFAS No. 123(R)

Prior to January 1, 2006, the Company accounted for stock-based compensation in accordance with the intrinsic value based method prescribed by APB No. 25. Under the intrinsic value based method, no compensation expense was recorded for stock options granted when the exercise price for options granted was equal to or greater than the fair value of the Company's common stock on the date of the grant.

Beginning January 1, 2006, the Company began accounting for stock-based compensation under SFAS No. 123(R), which applies to new awards and to awards modified, repurchased or cancelled after December 31, 2005. The Company recorded compensation expense based on the fair value of awards as described below. Additionally, compensation expense for the portion of the awards for which the requisite service period was not rendered that were outstanding at December 31, 2005 was or will be recognized as the requisite service is rendered on or after January 1, 2006.

Compensation expense charged against income for stock-based awards for the years ended December 31, 2007, 2006 and 2005 was $15.3 million, $21.2 million and $9.6 million, pre-tax, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations. The primary reasons for the decrease from 2007 to 2006 were due to a reduction in performance share expense from a change in the liability component of the awards resulting from the variance in the Company's relative ranking from 2006 to 2007 as well as a reduction in restricted stock awards as a result of awards that vested in 2007. Compensation expense in 2005 only included amortization of restricted stock grants and compensation expense related to performance shares and restricted stock units. The $0.6 million ($0.4 million, net of tax) cumulative effect charge at adoption that was recorded in the first quarter of 2006 was due primarily to the recording of the liability component of the Company's performance share awards at fair value, rather than intrinsic value. The Company recorded tax benefits related to stock-based compensation of $9.5 million and $3.7 million for the years ended December 31, 2006 and 2005, respectively, for tax deductions taken due to employee stock option exercises and restricted stock grant vesting. For the year ended December 31, 2007, the Company realized an $11.2 million tax benefit for the tax deduction in excess of book compensation cost associated with taxable employee stock-based compensation. In accordance with SFAS No. 123(R), the Company may recognize this tax benefit only to the extent it reduced the Company's income taxes payable for the year. For regular tax purposes, the Company was in a net operating loss position; thus the entire tax benefit of stock-based compensation for 2007 will be recorded only when the tax net operating loss is utilized to reduce income taxes payable or claim a refund of taxes paid in prior years.

Prior to the adoption of SFAS No. 123(R), the Company presented tax benefits resulting from tax deductions related to stock-based compensation as an operating cash flow. Under SFAS No. 123(R), 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 year ended December 31, 2006, $9.5 million was reported in these two separate line items in the Consolidated Statement of Cash Flows.

On October 26, 2005, the Compensation Committee of the Board of Directors of the Company approved the acceleration to December 15, 2005 of the vesting of 198,799 unvested stock options awarded in February 2003 under the Company's Second Amended and Restated 1994 Long-Term Incentive Plan and 24,500 unvested stock options awarded in April 2004 under the Company's 2004 Incentive Plan.

The 198,799 shares awarded to employees under the 1994 plan at an exercise price of $15.32 would have vested in February 2006. The 24,500 shares awarded to non-employee directors under the 2004 plan at an exercise price of $23.32 would have vested 12,250 shares in April 2006 and April 2007, respectively. The decision to accelerate the vesting of these unvested options, which the Company believed to be in the best interest of its shareholders and employees, was made solely to reduce compensation expense and administrative burden associated with the Company's adoption of SFAS No. 123(R). The accelerated vesting of the options did not have an impact on the Company's results of operations or cash flows in 2005. The acceleration of vesting reduced the Company's compensation expense related to these options by approximately $0.2 million for 2006.

During the third quarter of 2006, the Company adopted the provisions outlined under FSP FAS No. 123(R)-3, "Transition Election Related to Accounting for the Tax Effects of Share-Based Payment Awards," which discusses accounting for taxes for stock awards using the APIC Pool concept. The Company was not required to adopt this provision until January 1, 2007, one year from the adoption of 123(R); however, it chose early adoption. The Company made a one time election as prescribed under the FSP to use the shortcut approach to derive the initial windfall tax benefit pool. The Company chose to use a one-pool approach which combines all awards granted to employees, including non-employee directors.

The following table illustrates the effect on Net Income and Earnings per Share if the Company had applied the fair value recognition provisions of SFAS No. 123(R) to stock-based employee compensation during the year ended December 31, 2005:

(In thousands, except per share amounts)	
Net Income, as reported	$ 148,445
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	5,965
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of tax, previously not included in Net Income	(6,932)
Pro forma net income	$ 147,478
Earnings per Share:	
Basic - as reported	$ 1.52
Basic - pro forma	$ 1.51
Diluted - as reported	$ 1.49
Diluted - pro forma	$ 1.48
Share Count	97,713
Diluted Share Count	99,451

In September 2006, the SEC Staff issued a letter summarizing its views regarding the backdating of stock options. The letter discusses the date that is to be used as the measurement date for options in order to value the exercise price of stock options. It also discusses the documentation that should be available to support award grant dates. The Company reviewed its stock option granting practices and found no instances of backdating. Further, as required under the Company's incentive plans, the stock option grant date is the date on which the Compensation Committee and/or Board of Directors approves the award. Company management is given no discretion to choose the grant date. The Company maintains Compensation Committee and/or Board of Directors minutes and other records to support the grant dates of its options.

Restricted Stock Awards

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 dependant 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 three years. In accordance with SFAS No. 123(R), 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 SFAS No. 123(R). The Company used an annual forfeiture rate ranging from 0% to 3.3% 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, 2007:

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, 2006	797,644	$ 15.97		
Granted	51,900	32.92		
Vested	(350,576)	14.97		
Forfeited	(15,474)	17.98		
Non-vested shares outstanding at December 31, 2007	**483,494**	**$ 18.44**	**1.9**	**$ 19,519**

(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, 2007 by the number of non-vested restricted stock awards outstanding.

As shown in the table above, there were 51,900 shares of restricted stock granted to employees during 2007. Awards totaling 51,500 shares vest at the end of a three year service period commencing in July 2007. Awards totaling 400 shares vest over a two year service period commencing in October 2007 and are amortized using a graded-vesting schedule. During the year ended December 31, 2006, 93,700 restricted stock awards were granted with a weighted-average grant date fair value per share of $23.80. During the year ended December 31, 2005, 655,246 restricted stock awards were granted with a weighted-average grant date fair value per share of $15.94. The total fair value of shares vested during 2007, 2006 and 2005 was $5.2 million, $5.0 million and $2.2 million, respectively.

Compensation expense recorded for all unvested restricted stock awards for the years ended December 31, 2007, 2006 and 2005 was $3.4 million, $6.1 million and $5.6 million, respectively. Included in 2007 and 2006 restricted stock expense was $0.1 million and $0.6 million, respectively related to the immediate expensing of shares granted to retirement-eligible employees. Unamortized expense as of December 31, 2007 for all outstanding restricted stock awards was $2.3 million.

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, 2007:

Restricted Stock Units	Shares	Weighted-Average Grant Date Fair Value per share	Aggregate Intrinsic Value *(In thousands)*(1)
Outstanding at December 31, 2006	77,440	$ 19.99	
Granted and fully vested	24,654	35.49	
Issued	(17,042)	22.57	
Forfeited	—	—	
Outstanding at December 31, 2007	**85,052**	**$ 23.97**	**$ 3,434**

(1) The intrinsic value of restricted stock units is calculated by multiplying the closing market price of the Company's stock on December 31, 2007 by the number of outstanding restricted stock units.

As shown in the table above, 24,654 restricted stock units were granted during 2007. During 2006, 34,440 restricted stock units were granted with a weighted-average grant date fair value per share of $25.41. During 2005, 39,200 restricted stock units were granted with a weighted-average grant date fair value per share of $17.79.

The compensation cost, which reflects the total fair value of these units, recorded entirely in the first quarter of 2007 was $0.9 million. Compensation expense recorded during the years ended December 31, 2006 and 2005 for restricted stock units was $0.9 million and $0.7 million, respectively.

Stock Options

Stock option awards are granted with an exercise price equal to the fair 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 year ended December 31, 2007, there were no stock options granted. During the year ended December 31, 2006, 60,000 stock options, with an exercise price of $23.80 per share, were granted to two incoming non-employee directors of the Company. All of these stock options were granted in the first quarter of 2006. No stock options were granted in the year ended December 31, 2005.

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 2007 and 2006 for these stock options was $0.1 million and $0.3 million, respectively. Since the Company had not yet adopted SFAS No. 123(R) as of December 31, 2005, stock options were not expensed through the Consolidated Statement of Operations during 2005 and no compensation expense was recorded. Unamortized expense as of December 31, 2007 for all outstanding stock options was $0.1 million. The weighted-average period over which this compensation will be recognized is approximately 1.2 years.

The grant date fair value of a stock option is calculated by using a Black-Scholes model. The assumptions used in the Black-Scholes fair value calculation for stock options are as follows:

	Year Ended December 31,		
	2007	2006	2005
Weighted-Average Value per Option Granted During the Period (1)	**$ —**	$ 7.32	$ —
Assumptions			
Stock Price Volatility	**—**	31.5%	—
Risk Free Rate of Return	**—**	4.6%	—
Expected Dividend	**—**	0.3%	—
Expected Term (*In years*)	**—**	4.0	—

(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 stock option activity for the years ended December 31, 2007, 2006 and 2005:

	2007		2006		2005	
Stock Options	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at Beginning of Year	1,007,950	$ 9.03	1,826,696	$ 7.66	2,435,068	$ 7.61
Granted	—	—	60,000	23.80	—	—
Exercised	(619,000)	8.18	(876,946)	7.20	(600,986)	7.46
Forfeited or Expired	—	—	(1,800)	9.10	(7,386)	7.43
Outstanding at December 31(1)	**388,950**	**$ 10.38**	1,007,950	$ 9.03	1,826,696	$ 7.66
Options Exercisable at December 31(2)	**348,950**	**$ 8.84**	947,950	$ 8.09	1,791,696	$ 7.65

(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, 2007 was $11.7 million. The weighted-average remaining contractual term is 0.7 years.

(2) The aggregate intrinsic value of options exercisable at December 31, 2007 was $11.0 million. The weighted-average remaining contractual term is 0.4 years.

The total intrinsic value of options exercised during the years ended December 31, 2007, 2006 and 2005 was $19.9 million, $17.7 million and $6.9 million, respectively.

At December 31, 2007, the exercise price range for outstanding options was $6.42 to $23.80 per share. The following tables provide more information about the options by exercise price.

Options with exercise prices between $6.42 and $15.00 per share:

Options Outstanding	
Number of Options	338,950
Weighted Average Exercise Price	$ 8.40
Weighted Average Contractual Term *(In years)*	0.3

Options Exercisable	
Number of Options	338,950
Weighted Average Exercise Price	$ 8.40
Weighted Average Contractual Term *(In years)*	0.3

Options with exercise prices between $15.01 and $23.80 per share:

Options Outstanding	
Number of Options	50,000
Weighted Average Exercise Price	$ 23.80
Weighted Average Contractual Term *(In years)*	3.2

Options Exercisable	
Number of Options	10,000
Weighted Average Exercise Price	$ 23.80
Weighted Average Contractual Term *(In years)*	3.2

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 fair market value 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. As these SARs are paid out in stock, rather than in cash, 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,	
	2007	2006
Weighted-Average Value per Stock Appreciation Right Granted During the Period (1)	**$ 11.26**	$ 7.09
Assumptions		
Stock Price Volatility	**32.6%**	31.6%
Risk Free Rate of Return	**4.6%**	4.6%
Expected Dividend	**0.2%**	0.3%
Expected Term *(In years)*	**4.00**	3.75

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

These assumptions were derived using the same process as described in the "Stock Options" section above.

The following table is a summary of SAR activity for the years ended December 31, 2007 and 2006:

	2007		2006	
Stock Appreciation Rights	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at Beginning of Year	265,600	$ 23.80	—	$ —
Granted	107,200	35.22	265,600	23.80
Exercised	—	—	—	—
Forfeited or Expired	—	—	—	—
Outstanding at December 31(1)	**372,800**	**$ 27.08**	265,600	$ 23.80
SARs Exercisable at December 31(2)	**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, 2007 was $5.0 million. The weighted-average remaining contractual term is 5.4 years.

(2) The aggregate intrinsic value of SARs exercisable at December 31, 2007 was $1.5 million. The weighted-average remaining contractual term is 5.1 years.

As shown in the table above, the Compensation Committee granted 107,200 SARs with a grant date fair market value of $35.22 to employees during 2007. Compensation expense recorded during the year ended December 31, 2007 and 2006 for all outstanding SARs was $1.5 million and $1.0 million, respectively. Included in 2007 expense was $0.5 million related to the immediate expensing of shares granted to retirement-eligible employees. As no SARs were outstanding during 2005, no compensation expense was recorded for this type of award. Unamortized expense as of December 31, 2007 for all outstanding SARs was $0.6 million. The weighted-average period over which this compensation will be recognized is approximately 1.7 years.

Performance Share Awards

During 2007, the Compensation Committee granted three types of performance share awards to employees for a total of 387,100 performance shares. The performance period for two of these awards commenced on January 1, 2007 and ends December 31, 2009. Both of these types of awards vest at the end of the three year performance period.

Awards totaling 98,200 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 $30.72. 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 196,500 performance shares are earned, or not earned, based on the Company's internal performance metrics rather than performance compared to a peer group. The grant date per share value of this award was $35.22. 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, 2007, it is currently considered probable that these three criteria will be met.

The third performance share award, totaling 92,400 performance shares, with a grant date per share value of $35.22, has a three-year graded vesting schedule, vesting one-third on each anniversary date following the date of grant, provided that the Company has positive operating income for the year preceding the vesting date. If the Company does not have positive operating income 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, 2007, it is considered probable that this performance metric will be met.

For all awards granted to employees after January 1, 2006, an annual forfeiture rate ranging from 0% to 5.0% 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 SFAS No. 123(R) 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 three primary inputs for the Monte Carlo model are the risk-free rate, volatility of returns and correlation in movement of total shareholder return. The risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for six-month, one, two and three year bonds and is set equal to the yield, for the period over the remaining duration of the performance period, on treasury securities as of the reporting date. Volatility was set equal to the annualized daily volatility measured over a historic four year 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 35% to approximately 77% for the Company and its peer group. 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, 2007 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.

	As of December 31, 2007
Risk Free Rate of Return	**3.0% - 3.4%**
Stock Price Volatility	**30.4% - 34.5%**
Expected Dividend	**0.3%**

The Monte Carlo value per share for the liability component for all outstanding market condition performance share awards ranged from $8.89 to $21.36 at December 31, 2007. The long-term liability for all market condition performance share awards, included in Other Liabilities in the Consolidated Balance Sheet, at December 31, 2007 and 2006 was $0.2 million and $3.9 million, respectively. The short-term liability, included in Accrued Liabilities in the Consolidated Balance Sheet, at December 31, 2007 and 2006, for certain market condition performance share awards was $5.5 million and $4.6 million, respectively.

The following table is a summary of performance share award activity for the year ended December 31, 2007:

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, 2006	940,100	$ 14.83		
Granted	387,100	34.08		
Vested	(450,000)	10.75		
Forfeited	(9,500)	33.46		
Non-vested shares outstanding at December 31, 2007	**867,700**	**$ 25.38**	**1.9**	**$ 35,029**

(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, 2007 by the number of non-vested performance share awards outstanding.

During the year ended December 31, 2006, 285,500 performance share awards were granted with a weighted-average grant date fair value per share of $21.07. During the year ended December 31, 2005, 220,400 performance share awards were granted with a grant date fair value per share of $15.22. During the year ended December 31, 2006, 30,600 performance shares vested as a result of the death of one of the Company's officers. No performance shares vested in 2005. During 2006 and 2005, 7,100 and 17,400 performance shares, respectively, were forfeited.

Total unamortized compensation cost related to the equity component of performance shares at December 31, 2007 was $9.8 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 (including the cumulative effect) and liability components of performance share awards during the years ended December 31, 2007, 2006 and 2005 was $9.4 million, $12.9 million and $3.3 million, respectively.

Supplemental Employee Incentive Plan

On January 16, 2008, the Company's Board of Directors adopted a Supplemental Employee Incentive Plan. The plan is 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. Certain retirees are also eligible to participate in the plan.

The plan provides a total bonus pool of up to $45 million, as determined by the Compensation Committee of the Company's Board of Directors. The bonus pool becomes available if, for any 20 trading days (which need not be consecutive) that fall within a period of 60 consecutive trading days occurring prior to November 1, 2011, the closing price per share of the Company's common stock equals or exceeds the price goal of $60 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 the plan, each eligible employee will receive a minimum distribution of 50% of his or her base salary as of the Final Trigger Date, as adjusted for persons hired after June 30, 2008 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 will allocate to eligible employees in its discretion the pool remaining after making the minimum distributions.

The plan also provides that up to 20%, or $9 million, of the total bonus pool, as determined by the Compensation Committee, will be paid as interim distributions to eligible employees upon achieving the interim price goal of $50 per share prior to December 31, 2009. Interim distributions are determined as described above except that interim distributions will be based on 10%, rather than 50%, of salary.

11. 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 Company uses available market data and valuation methodologies to estimate the fair value of debt. This disclosure is presented in accordance with SFAS No. 107, "Disclosures about Fair Value of Financial Instruments" and does not impact the Company's financial position, results of operations or cash flows.

Long-Term Debt

	December 31, 2007		December 31, 2006	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Long-Term Debt				
7.19% Notes	**$ 40,000**	**$ 41,376**	$ 60,000	$ 61,749
7.26% Notes	**75,000**	**80,066**	75,000	80,335
7.36% Notes	**75,000**	**81,259**	75,000	82,025
7.46% Notes	**20,000**	**21,799**	20,000	22,547
Credit Facility	**140,000**	**140,000**	10,000	10,000
Current Maturities				
7.19% Notes	**(20,000)**	**(20,466)**	(20,000)	(20,299)
Long-Term Debt, excluding Current Maturities	**$ 330,000**	**$ 344,034**	$ 220,000	$ 236,357

The fair value of long-term debt is the estimated cost to acquire the debt, including a premium or discount for the difference between the issue rate and the year end market rate. The fair value of the 7.19% Notes, the 7.26% Notes, the 7.36% Notes and the 7.46% Notes 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.

Derivative Instruments and Hedging Activity

The Company periodically enters into derivative commodity instruments to hedge its exposure to price fluctuations on natural gas and crude oil production. Under the Company's revolving credit agreement, the aggregate level of commodity hedging must not exceed 100% of the anticipated future equivalent production during the period covered by these cash flow hedges. At December 31, 2007, the Company had 16 cash flow hedges open: 12 natural gas price collar arrangements, three natural gas swap arrangements and one crude oil collar arrangement. At December 31, 2007, a $7.3 million ($4.6 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income, along with a $12.7 million short-term derivative receivable and a $5.4 million short-term derivative liability. The change in the fair value of derivatives designated as hedges that is effective is initially recorded to Accumulated Other Comprehensive Income. The ineffective portion, if any, of the change in the fair value of derivatives designated as hedges, and the change in fair value of all other derivatives is recorded currently in earnings as a component of Natural Gas Production and Crude Oil and Condensate Revenue, as appropriate. During 2007 and 2006, there was no ineffectiveness recorded in the Consolidated Statement of Operations. For the year ended December 31, 2005, a $6.6 million gain was recorded as a component of revenue, which reflected the ineffective portion of the change in fair value of derivatives designated as hedges and the change in the fair value of all other derivatives.

Assuming no change in commodity prices, after December 31, 2007 the Company would expect to reclassify to the Consolidated Statement of Operations, over the next 12 months, $4.6 million in after-tax income associated with commodity hedges. This reclassification represents the net short-term receivable associated with open positions currently not reflected in earnings at December 31, 2007 related to anticipated 2008 production.

Hedges on Production – Swaps. From time to time, the Company enters into natural gas and crude oil swap agreements with counterparties to hedge price risk associated with a portion of its production. These cash flow hedges are not held for trading purposes. Under these price swaps, the Company receives 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 2007, the Company did not enter into any natural gas price swaps covering its 2007 production.

At December 31, 2007, the Company had open natural gas price swap contracts covering a portion of its 2008 production as follows:

	Natural Gas Price Swaps		
Contract Period	Volume in Mmcf	Weighted-Average Contract Price *(per Mcf)*	Net Unrealized Gain *(In thousands)*
As of December 31, 2007			
First Quarter 2008	1,233	$ 7.44	
Second Quarter 2008	1,233	7.44	
Third Quarter 2008	1,246	7.44	
Fourth Quarter 2008	1,246	7.44	
Full Year 2008	**4,958**	**$ 7.44**	**$ 472**

Hedges on Production - Options. From time to time, the Company enters into natural gas and crude oil collar agreements with counterparties to hedge price risk associated with a portion of its production. These cash flow hedges are not held for trading purposes. Under the collar arrangements, if the index price rises above the ceiling price, the Company pays the counterparty. If the index price falls below the floor price, the counterparty pays the Company. During 2007, natural gas price collars covered 42,533 Mmcf of the Company's gas production, or 53% of gas production with a weighted-average floor of $8.99 per Mcf and a weighted-average ceiling of $12.19 per Mcf.

At December 31, 2007, the Company had open natural gas price collar contracts covering a portion of its 2008 production as follows:

	Natural Gas Price Collars		
Contract Period	Volume in Mmcf	Weighted-Average Ceiling / Floor *(per Mcf)*	Net Unrealized Gain *(In thousands)*
As of December 31, 2007			
First Quarter 2008	8,523	$ 10.14 / $8.17	
Second Quarter 2008	8,523	10.14 / 8.17	
Third Quarter 2008	8,617	10.14 / 8.17	
Fourth Quarter 2008	8,617	10.14 / 8.17	
Full Year 2008	**34,280**	**$ 10.14 / $8.17**	**$ 12,072**

During 2007, an oil price collar covered 365 Mbbls of the Company's crude oil production, or 44% of its crude oil production, with a floor of $60.00 per Bbl and a ceiling of $80.00 per Bbl.

At December 31, 2007, the Company had one open crude oil price collar contract covering a portion of its 2008 production as follows:

	Crude Oil Price Collars		
Contract Period	Volume in Mbbl	Ceiling / Floor *(per Bbl)*	Net Unrealized Loss *(In thousands)*
As of December 31, 2007			
First Quarter 2008	91	$ 80.00 / $60.00	
Second Quarter 2008	91	80.00 / 60.00	
Third Quarter 2008	92	80.00 / 60.00	
Fourth Quarter 2008	92	80.00 / 60.00	
Full Year 2008	**366**	**$ 80.00 / $60.00**	**$ (5,272)**

The Company is 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.

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 2007 and 2006, no customer accounted for more than 10% of the Company's total sales. In 2005, approximately 11% of the Company's total sales were made to one customer.

12. 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, 2007, 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, 2007, 2006 and 2005 was $1.1 million, $1.4 million and $1.4 million, respectively, and was included within Depreciation, Depletion and Amortization expense on the Company's Consolidated Statement of Operations.

The following table reflects the changes of the asset retirement obligations during the current period.

(In thousands)	
Carrying amount of asset retirement obligations at December 31, 2006	$ 22,655
Liabilities added during the current period	1,565
Liabilities settled and divested during the current period	(553)
Current period accretion expense	1,057
Carrying amount of asset retirement obligations at December 31, 2007	**$ 24,724**

13. Earnings per Common Share

Basic earnings per common share (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, 2007, 2006 and 2005:

	December 31,		
	2007	2006	2005
Weighted-Average Shares - Basic	**96,977,634**	96,803,283	97,712,982
Dilution Effect of Stock Options and Awards at End of Period	**1,152,673**	1,797,700	1,737,808
Weighted-Average Shares - Diluted	**98,130,307**	98,600,983	99,450,790
Weighted-Average Stock Awards and Shares Excluded from Diluted Earnings per Share due to the Anti-Dilutive Effect	**21,639**	—	—

14. Accumulated Other Comprehensive Income

Changes in the components of accumulated other comprehensive income / (loss), net of taxes, for the years ended December 31, 2007, 2006 and 2005 were as follows:

(In thousands)	Net Gains / (Losses) on Cash Flow Hedges	Defined Benefit Pension and Postretirement Plans	Foreign Currency Translation Adjustment	Total
Balance at December 31, 2004	$ (17,843)	$ (3,042)	$ 534	$ (20,351)
Net change in unrealized gains on cash flow hedges, net of taxes of $(3,111)	4,983	—	—	4,983
Net change in minimum pension liability, net of taxes of $77	—	(128)	—	(128)
Change in foreign currency translation adjustment, net of taxes of $(427)	—	—	381	381
Balance at December 31, 2005	$ (12,860)	$ (3,170)	$ 915	$ (15,115)
Net change in unrealized gains on cash flow hedges, net of taxes of $(38,625)	64,099	—	—	64,099
Net change in minimum pension liability, net of taxes of $(1,848)	—	3,081	—	3,081
Effect of adoption of SFAS No. 158, net of taxes of $8,447	—	(14,079)	—	(14,079)
Change in foreign currency translation adjustment, net of taxes of $507	—	—	(826)	(826)
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)**

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 in effect when the estimates were made.

Proved developed reserves are proved reserves expected to be recovered through wells and equipment in place and under operating methods used when the estimates were made.

Estimates of proved and proved developed reserves at December 31, 2007, 2006, and 2005 were based on studies performed by the Company's petroleum engineering staff. The 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 6, 2008, 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, 2007, is believed to have caused a material change in the estimates of proved or proved developed reserves as of that date.

The following table illustrates the Company's net proved reserves, including changes, and proved developed reserves for the periods indicated, as estimated by the Company's engineering staff.

	Natural Gas		
	December 31,		
(Millions of cubic feet)	**2007**	2006	2005
Proved Reserves			
Beginning of Year	**1,368,293**	1,262,096	1,134,081
Revisions of Prior Estimates	**2,604**	(17,675)	(1,543)
Extensions, Discoveries and Other Additions	**265,830**	246,197	185,884
Production	**(80,475)**	(79,722)	(73,879)
Purchases of Reserves in Place	**3,701**	1,946	17,567
Sales of Reserves in Place	**—**	(44,549)	(14)
End of Year	**1,559,953**	1,368,293	1,262,096
Proved Developed Reserves	**1,133,937**	996,850	944,897
Percentage of Reserves Developed	**72.7%**	72.9%	74.9%

	Liquids		
	December 31,		
(Thousands of barrels)	**2007**	2006	2005
Proved Reserves			
Beginning of Year	**7,973**	11,463	11,384
Revisions of Prior Estimates	**771**	673	1,073
Extensions, Discoveries and Other Additions	**1,381**	1,066	334
Production	**(830)**	(1,415)	(1,747)
Purchases of Reserves in Place	**33**	38	419
Sales of Reserves in Place	**—**	(3,852)	—
End of Year	**9,328**	7,973	11,463
Proved Developed Reserves	**7,026**	5,895	9,127
Percentage of Reserves Developed	**75.3%**	73.9%	79.6%

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)	**2007**	2006	2005
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	**$ 3,007,849**	$ 2,462,693	$ 2,290,147
Aggregate Accumulated Depreciation, Depletion and Amortization	**1,100,369**	983,079	1,052,654

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)	**2007**	2006	2005
Property Acquisition Costs, Proved	**$ 3,982**	$ 6,688	$ 73,127
Property Acquisition Costs, Unproved	**22,186**	42,551	22,126
Exploration Costs [(1)]	**70,242**	109,525	102,957
Development Costs	**494,204**	346,787	208,124
Total Costs	**$ 590,614**	$ 505,551	$ 406,334

(1) Includes administrative exploration costs of $13,761, $13,486 and $12,423 for the years ended December 31, 2007, 2006 and 2005, respectively.

Historical Results of Operations from Oil and Gas Producing Activities

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

	Year Ended December 31,		
(In thousands)	**2007**	2006	2005
Operating Revenues	**$ 637,195**	$ 659,884	$ 581,849
Costs and Expenses			
Production	**116,020**	115,786	103,477
Other Operating	**40,620**	46,212	30,120
Exploration (1)	**39,772**	49,397	61,840
Depreciation, Depletion and Amortization	**140,957**	124,204	106,156
Impairment of Unproved Properties	**19,042**	11,117	12,966
Impairment of Oil & Gas Properties	**4,614**	3,886	—
Total Costs and Expenses	**361,025**	350,602	314,559
Income Before Income Taxes	**276,170**	309,282	267,290
Provision for Income Taxes	**100,755**	113,355	100,353
Results of Operations	**$ 175,415**	$ 195,927	$ 166,937

(1) Includes administrative exploration costs of $13,761, $13,486 and $12,423 for the years ended December 31, 2007, 2006 and 2005, respectively.

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

The following information has been developed utilizing SFAS No. 69, *"Disclosures about Oil and Gas Producing Activities"*, 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 were estimated by applying year end oil and gas prices to the estimated future production of year end proved reserves.

The average prices related to proved reserves at December 31, 2007, 2006, and 2005 for natural gas ($ per Mcf) were $6.91, $5.54 and $9.53, respectively, and for oil ($ per Bbl) were $94.94, $59.50 and $58.48, 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. SFAS No. 69 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:

(In thousands)	Year Ended December 31, 2007	2006	2005
Future Cash Inflows	**$11,671,078**	$ 8,054,737	$ 12,700,390
Future Production Costs	**(2,690,695)**	(2,000,993)	(2,271,917)
Future Development Costs	**(909,374)**	(688,955)	(536,333)
Future Income Tax Expenses	**(2,684,271)**	(1,763,458)	(3,588,877)
Future Net Cash Flows	**5,386,738**	3,601,331	6,303,263
10% Annual Discount for Estimated Timing of Cash Flows	**(3,216,087)**	(2,125,081)	(3,652,030)
Standardized Measure of Discounted Future Net Cash Flows [1]	**$ 2,170,651**	$ 1,476,250	$ 2,651,233

(1) The standardized measures of discounted future net cash flows before taxes were $3,007,661, $2,010,228 and $4,001,769 for the years ended December 31, 2007, 2006 and 2005, respectively.

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, 2007	2006	2005
Beginning of Year	**$ 1,476,250**	$ 2,651,233	$ 1,580,357
Discoveries and Extensions, Net of Related Future Costs	**430,918**	278,258	494,773
Net Changes in Prices and Production Costs	**864,630**	(1,843,272)	1,278,303
Accretion of Discount	**201,023**	400,177	235,843
Production, Timing and Other	**(122,908)**	(106,253)	(49,550)
Development Costs Incurred	**136,781**	85,993	61,802
Sales and Transfers, Net of Production Costs	**(521,558)**	(544,650)	(471,638)
Net Purchases / (Sales) of Reserves in Place	**8,548**	(261,795)	91,180
Net Change in Income Taxes	**(303,033)**	816,559	(569,837)
End of Year	**$ 2,170,651**	$ 1,476,250	$ 2,651,233

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
2007					
Operating Revenues	**$ 191,573**	**$ 175,832**	**$ 170,848**	**$ 193,917**	**$ 732,170**
Impairment of Oil and Gas Properties [1]	**—**	**—**	**4,614**	**—**	**4,614**
Operating Income [2]	**79,185**	**70,245**	**55,521**	**69,742**	**274,693**
Net Income [2]	**48,547**	**41,376**	**35,453**	**42,047**	**167,423**
Basic Earnings per Share	**0.50**	**0.43**	**0.37**	**0.43**	**1.73**
Diluted Earnings per Share	**0.50**	**0.42**	**0.36**	**0.43**	**1.71**
2006					
Operating Revenues	$ 214,768	$ 190,794	$ 184,744	$ 171,682	$ 761,988
Impairment of Oil and Gas Properties [1]	—	—	—	3,886	3,886
Operating Income [2] [3]	91,224	77,881	304,746	55,095	528,946
Net Income [2]	53,165	46,864	189,020	32,126	321,175
Basic Earnings per Share [4]	0.55	0.48	1.96	0.33	3.32
Diluted Earnings per Share [4]	0.54	0.47	1.92	0.33	3.26

(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 third and fourth quarters of 2006 and first and second quarters of 2007 contain the gain on the disposition of offshore and certain south Louisiana properties of $229.7 million, $1.5 million, $7.9 million and $4.4 million, respectively.

(3) Included in Operating Income in the first quarter is the cumulative effect loss of $0.4 million, previously reported in a separate line item below Operating Income. Due to immateriality for year end reporting purposes, this amount was reclassified to the General and Administrative Expense component of Operating Income in the Consolidated Statement of Operations.

(4) All earnings per share figures have been retroactively adjusted for the 2-for-1 split of the Company's common stock effective March 30, 2007.

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 the end of December 31, 2007, 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 significant 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, 2007. 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, 2007, 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, 2007, 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 2008 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 2008 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 2008 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 2008 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 2008 annual stockholders' meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 64.

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.

Exhibit Number	Description
3.1	Certificate of Incorporation of the Company (Registration Statement No. 33-32553).
3.2	Amended and Restated Bylaws of the Company amended May 2, 2007 (Form 10-Q for the quarter ended March 31, 2007).
3.3	Certificate of Amendment of Certificate of Incorporation (Form 8-K for July 1, 2002).
3.4	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for July 1, 2002).
3.5	Certificate of Amendment of Certificate of Incorporation (Form 8-K for June 1, 2006).
3.6	Certificate of Increase of Shares Designated Series A Junior Participating Preferred Stock (Form 8-K for June 1, 2006).
4.1	Form of Certificate of Common Stock of the Company (Registration Statement No. 33-32553).
4.2	Certificate of Designation for Series A Junior Participating Preferred Stock (Form 10-K for 1994).

Exhibit Number	Description
4.3	Rights Agreement dated as of March 28, 1991, between the Company and The First National Bank of Boston, as Rights Agent, which includes as Exhibit A the form of Certificate of Designation of Series A Junior Participating Preferred Stock (Form 8-A, File No. 1-10477). (a) Amendment No. 1 to the Rights Agreement dated February 24, 1994 (Form 10-K for 1994). (b) Amendment No. 2 to the Rights Agreement dated December 8, 2000 (Form 8-K for December 21, 2000). (c) Amendment to the Rights Agreement dated January 1, 2003 (The Bank of New York as rights agent) (Form 10-Q for the quarter ended March 31, 2007). (d) Amendment to the Rights Agreement dated March 30, 2007 (regarding uncertified shares) (Form 10-Q for the quarter ended March 31, 2007).
4.4	Certificate of Designation for 6% Convertible Redeemable Preferred Stock (Form 10-K for 1994).
4.5	Amended and Restated Credit Agreement dated as of May 30, 1995, among the Company, Morgan Guaranty Trust Company, as agent and the banks named therein (Form 10-K for 1995). (a) Amendment No. 1 to Credit Agreement dated September 15, 1995 (Form 10-K for 1995). (b) Amendment No. 2 to Credit Agreement dated December 24, 1996 (Form 10-K for 1996).
4.6	Note Purchase Agreement dated November 14, 1997, among the Company and the purchasers named therein (Form 10-K for 1997).
4.7	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).
4.8	Credit Agreement dated as of October 28, 2002 among the Company, the Banks Parties Hereto and Fleet National Bank, as administrative agent (Form 10-Q for the quarter ended September 30, 2002). (a) Amendment No. 1 to Credit Agreement dated December 10, 2004 (Form 10-K for 2004).
* 10.1	Form of Change in Control Agreement between the Company and Certain Officers (Form 10-K for 2001).
* 10.2	Supplemental Executive Retirement Agreements of the Company (Form 10-K for 1991).
* 10.3	1990 Non-employee Director Stock Option Plan of the Company (Form S-8 dated June 23, 1990). (a) First Amendment to 1990 Non-employee Director Stock Option Plan (Post-Effective Amendment No. 2 to Form S-8 dated March 7, 1994). (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 September 1, 2001 (Form 10-K for 2001).
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	Credit Agreement dated as of December 17, 1998, between the Company and the banks named therein (Form 10-K for 1998).
* 10.11	Employment Agreement between the Company and Dan O. Dinges dated August 29, 2001 (Form 10-K for 2001).
* 10.12	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).

Exhibit Number	Description
*10.13	2004 Performance Award Agreement (Form 10-Q for the quarter ended June 30, 2004).
* 10.14	2004 Annual Target Cash Incentive Plan Measurement Criteria for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
* 10.15	Form of Restricted Stock Awards Terms and Conditions for Cabot Oil & Gas Corporation (Form 8-K for February 10, 2005).
* 10.16	2005 Form of Non-Employee Director Restricted Stock Unit Award Agreement (Form 8-K for May 24, 2005).
* 10.17	Savings Investment Plan of the Company, as amended and restated effective January 1, 2001 (Form 10-K for 2005). (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).
* 10.18	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).
10.19	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).
10.20	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).
* 10.21	Form of Amendment of Employee Award Agreements (Form 8-K for December 19, 2006).
* 10.22	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.
* 10.23	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.
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).
16.1	Letter, dated March 12, 2007, from UHY Mann Frankfort Stein & Lipp CPAs, LLP to the Securities and Exchange Commission (Form 8-K for March 8, 2007).
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.

** Compensatory plan, contract or arrangement.*

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 27th of February 2008.

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 27, 2008
/s/ Scott C. Schroeder Scott C. Schroeder	Vice President and Chief Financial Officer (Principal Financial Officer)	February 27, 2008
/s/ Henry C. Smyth Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	February 27, 2008
/s/ John G. L. Cabot John G. L. Cabot	Director	February 27, 2008
/s/ David M. Carmichael David M. Carmichael	Director	February 27, 2008
/s/ Robert L. Keiser Robert L. Keiser	Director	February 27, 2008
/s/ Robert Kelley Robert Kelley	Director	February 27, 2008
/s/ P. Dexter Peacock P. Dexter Peacock	Director	February 27, 2008
/s/ William P. Vititoe William P. Vititoe	Director	February 27, 2008

Corporate **Information**

Officers

Dan O. Dinges
Chairman, President and Chief Executive Officer

Michael B. Walen
Senior Vice President, Chief Operating Officer

Scott C. Schroeder
Vice President and Chief Financial Officer

J. Scott Arnold
Vice President, Land and Associate 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

Thomas S. Liberatore
Vice President, Regional Manager, East Region

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

Henry C. Smyth
Vice President, Controller and Treasurer

Annual Meeting

The annual meeting of the shareholders will be held Wednesday, April 30, 2008, at 8:00 a.m. (CDT) at the corporate office in Houston, Texas.

Corporate Office

Cabot Oil & Gas Corporation
1200 Enclave Parkway
Houston, Texas 77077
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 and Chief Financial Officer
(281) 589-4993
scott.schroeder@cabotog.com

Transfer Agent/Registrar

BNY Mellon Shareowner Services
P.O. Box 358015
Pittsburgh, Pennsylvania 15252-8015
(866) 201-5655
(201) 680-6685 (Outside the U.S.)
(800) 231-5469 (Hearing Impaired – TDD Phone)
(201) 680-6610 (TDD Foreign Shareholders)
www.bnymellon.com/shareowner/isd

Send Certificates for Transfer and Address Changes to:
BNY Mellon Shareowner Services
480 Washington Boulevard
Jersey City, New Jersey 07310-1900

Corporate Governance Matters

On May 2, 2007, 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 2007 quarterly reports on Form 10-Q and the 2007 annual report on Form 10-K as mandated by the Sarbanes-Oxley Act of 2002.

Design: CROXSON Design, www.croxsondesign.com

1200 Enclave Parkway Houston, Texas 77077-1607 (281) 589-4600 www.cabotog.com

Cabot Oil & Gas Corporation