Cabot Oil & Gas Corporation

2006 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.

Financial Highlights

	Year Ended December 31, 2004	2005	2006
Financial Data *(In millions, except share amounts)*			
Operating Revenues	$ 530.4	$ 682.8	**$ 762.0**
Net Income	$ 88.4	$ 148.4	**$ 321.2**
Per Share (1)	$ 1.81	$ 3.04	**$ 6.64**
Discretionary Cash Flow (2)	$ 294.3	$ 374.4	**$ 355.8**
Per Share (1)	$ 6.04	$ 7.66	**$ 7.35**
Capital and Exploration Expenditures	$ 259.5	$ 425.6	**$ 537.5**
Common Dividends per Share (1)	$ 0.11	$ 0.15	**$ 0.16**
Average Common Shares Outstanding *(In thousands)*	48,733	48,856	**48,402**
Capitalization *(In millions)*			
Long-Term Debt	$ 250.0	$ 320.0	**$ 220.0**
Shareholders' Equity *(Successful Efforts Method)*	$ 455.7	$ 600.2	**$ 945.2**
Annual Production Volume			
Bcfe	84.8	84.4	**88.2**
% Growth	(5%)	(1%)	**5%**
% Gas	86%	88%	**90%**
Proved Reserves (3)			
Natural Gas *(Bcf)*	1,134.1	1,262.1	**1,368.3**
Oil, Condensate and Natural Gas Liquids *(Mmbbl)*	11.4	11.5	**8.0**
Total Proved *(Bcfe)*	1,202.4	1,330.9	**1,416.1**
Total Developed *(Bcfe)*	909.7	999.7	**1,032.2**
% Gas	94%	95%	**97%**
% Developed	76%	75%	**73%**
Reserve Life *(Years)*	14.2	15.8	**16.1**
Reserve Additions			
Drilling Additions *(Bcfe)*	147.4	187.9	**252.6**
Drilling Additions, Revisions and Purchases *(Bcfe)*	146.2	212.9	**241.1**
Reserve Replacement %	172%	252%	**273%**
Reserve Replacement Costs – Additions *($ per Mcfe)*	$ 1.63	$ 1.77	**$ 1.97**
Reserve Replacement Costs – Additions, Revisions and Purchases *($ per Mcfe)*	$ 1.67	$ 1.91	**$ 2.10**
Wells Drilled			
Total Gross	256	316	**387**
Total Net	219.8	247.1	**307.0**
Gross Success Rate %	95%	95%	**96%**
Produced Average Natural Gas Sales Price *($ per Mcf)*			
East	$ 5.60	$ 8.02	**$ 7.99**
Gulf Coast	$ 5.27	$ 6.38	**$ 7.37**
West	$ 4.75	$ 6.00	**$ 6.05**
Canada	$ 4.69	$ 6.79	**$ 6.18**
Total Company	$ 5.20	$ 6.74	**$ 7.13**
Crude and Condensate Price *($ per Bbl)*	$ 31.55	$ 44.19	**$ 65.03**

(1) Prior years have been adjusted to reflect a 3-for-2 stock split in 2005.

(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 104 of this report for details.*

To Our Shareholders:

2006 can easily be described as our best year as a public company. Operationally, we hit our stride with growth coming from all regions. Strategically, we refined our portfolio by selling assets no longer core to our direction. Financially, we achieved our maximum profit so far and used the asset sales proceeds to de-lever the Company.

Production

Cabot returned to a growing production profile in 2006 with an absolute growth rate of 4.6 percent. The 88.2 Bcfe reported production figure was the third highest ever reported and came even after the asset sale of 36 Mmcfe per day that was completed on September 29, 2006. In the sale, the Company sold its high decline south Louisiana and offshore portfolios, reducing its overall annual decline curve from 20 percent to 15 percent in the process.

The 2006 growth figures for Cabot improve dramatically when comparing production levels for the "going forward" assets. Pro forma production for 2006 was 74.9 Bcfe, compared to 64.0 Bcfe for 2005, providing for 17 percent growth in the Company's production.

Just as important is the impact to the growth profile of the Gulf Coast region. After removing production attributed to the sold assets for both 2006 and 2005, year over year growth is 40 percent.

From the revised base, Cabot expects double-digit production growth year after year. For 2007, the pro forma guidance is 12 to 18 percent from the organic program. These are levels the Company has experienced only once, and that was as a result of an acquisition. Based on the capital allocations going forward, each region will contribute to the growth profile in 2007.

Because of these events, our market value has increased 47 percent since our correspondence last year, surpassing $3.0 billion at year end for the first time. This move prompted the Board of Directors to declare a two-for-one stock split, effective March 30, 2007. What is impressive is that this move occurred in a commodity price market that experienced a 16 percent drop in natural gas prices and a 17 percent increase in oil prices between year ends.

What has changed? Cabot Oil & Gas today has transitioned from a company whose investment profile focused heavily on higher risk opportunities to a company focused on low-risk resources, complemented by exploration. Our refined portfolio and dedicated employee base afford us repeatable growth opportunities for both reserves and production, at "top of the class" finding cost levels.

Operational Highlights

- For the first time since 2002, Cabot grew production versus the prior year. The 4.6 percent growth level was achieved in spite of removing 36 Mmcfe per day of Gulf Coast production in the fourth quarter due to the asset sale (see inset regarding production for more details).
- Total proved reserves increased to 1,416 Bcfe on the strength of the Company's largest drilling program in its history. The 6.4 percent increase reflects sold reserves of 68 Bcfe and suppressed year-end commodity prices that resulted in a reduction in the overall growth of reserves. However, more importantly, the drilling program added a record 253 Bcfe.
- The inflationary period we have experienced for goods and services in the energy sector has adversely affected the cost management for many companies. In this environment it is impressive to be able to report an all-in finding cost of $2.10 per Mcfe. This clearly separates Cabot as an industry leader.

Strategic

- During the first half of 2006, we made the decision to exit south Louisiana and offshore due to the risk profile of the remaining opportunities and our expanded portfolio of lower risk opportunities in our core areas.
- In the asset sale transaction (which closed September 29, 2006) the Company received $340 million for 68 Bcfe of proved reserves, a $5.00 per Mcfe price. This turned out to be one of the top – if not the top – prices paid in 2006 for reserves in the ground.
- The sale had the positive effect of reducing our overall annual decline curve from 20 percent to 15 percent. This affords us the availability of additional growth capital to allocate each year as we now have less production decline to overcome.

Financial

- On the strength of an expanded production profile and stronger realized commodity prices, assisted by a strong hedge position, the Company recorded net income of $178.5 million, or $3.69 per share for the year from its traditional operations. Including the gain associated with the sale of our south Louisiana and offshore portfolios, the reported net income figure is a robust $321.2 million, or $6.64 per share.
- During the year, the energy sector moved in and out of favor in response to commodity prices. We took advantage of those swings and repurchased 1.1 million shares of our common stock at a weighted average price of $42.71 per share.
- From the asset sale, Cabot received $340 million of proceeds, which the Company used to payoff its revolving line of credit, repurchase shares, fund operations and pay the associated tax bill. The Company ended the year with $240 million of debt, $42 million in cash and book equity of $945 million – resulting in a net debt-to-capitalization ratio of 17 percent, well below any other time in our history.

After transitioning Cabot back to its development/exploitation roots, we are positioned for years of low-risk growth through our organic portfolio. The long-term plans, which were set in motion in 2002, have now made way for our short-term initiatives of growth year after year.

Looking Ahead

In 2007, our plan is to execute the largest organic drilling program this Company has experienced. This program will deliver double-digit growth in production and reserves – all at an industry leading finding cost.

We are aware of the volatility in the commodity price environment, but with approximately 50 percent of our anticipated production for 2007 hedged with an average floor price of over $8.00 per Mcfe and an unlevered balance sheet, we are prepared to execute our 2007 program.

We will continue to take advantage of the volatility in the marketplace to buy back stock, particularly when the implied repurchase price is competitive with the finding cost from our organic program. Additionally, our goal is to be dilution neutral after equity awards to our employees.

In 2007, a strategic objective is to establish a method to accelerate our realizations of reserves, i.e., bring our asset closer. We calculated that we have a 20 year drilling inventory (including proved undeveloped, probable and possible locations) at current activity levels. The value accretion if we could accelerate our program by a third or more would be significant.

In the last three years we have tripled our market value and I believe strongly that with our program for drilling, portfolio of assets and financial position the next three years will also see significant value creation. I look forward to next year's update and continued positive value creation.

Sincerely,

Dan O. Dinges

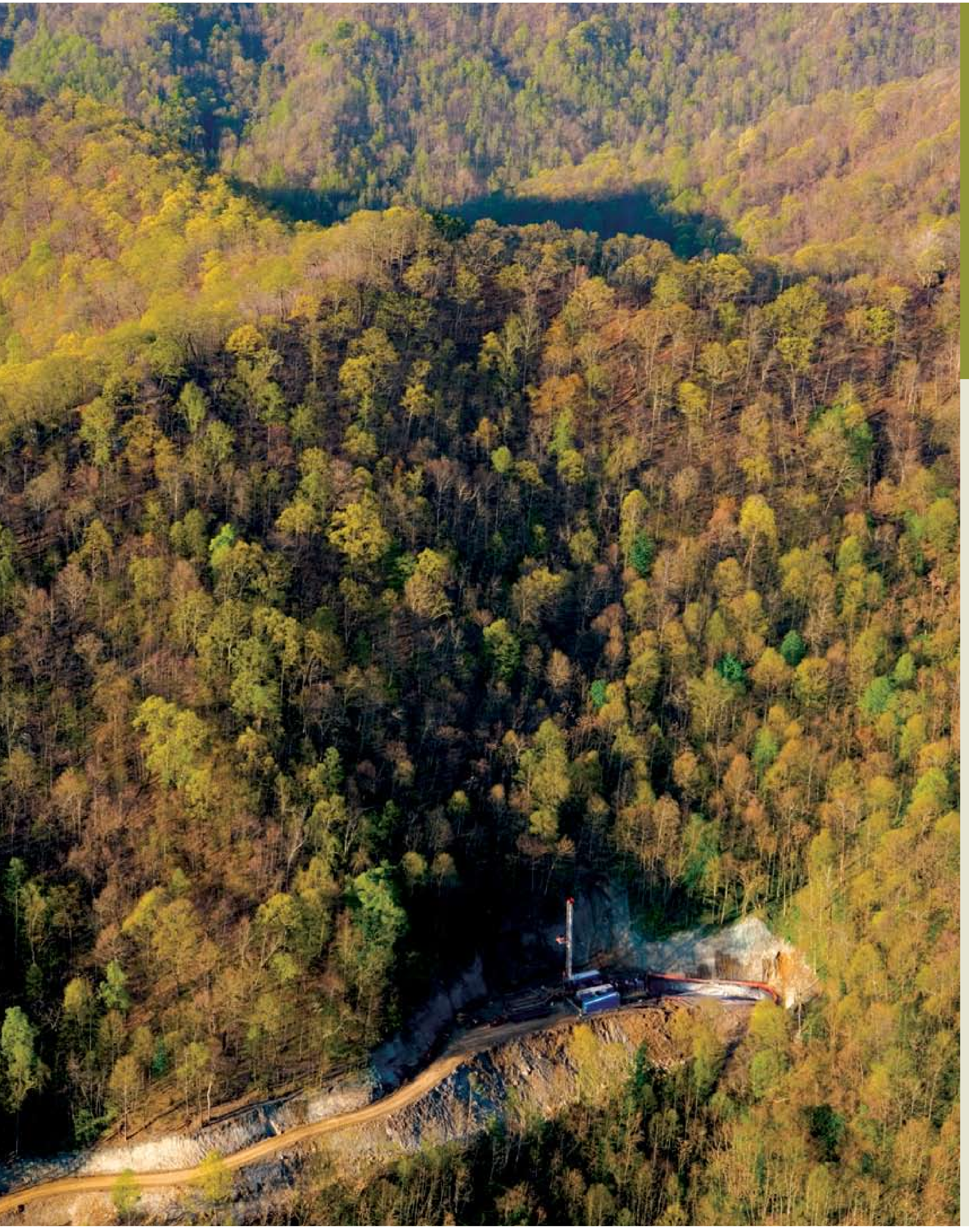
Dan O. Dinges

Chairman, President and Chief Executive Officer

East Region

Everything old is new again. In an industry that is hungry for new opportunities, the previously undervalued Appalachian basin has attracted renewed interest. Buoyed by high commodity prices, low risk, and a niche geographic position relative to the premium northeast market, the basin has experienced a dramatic increase in investment over the last few years.

Left to right: Jeff Keim, Regional Land Manager; Doug Gosnell, District Engineer; Jim Wilson, District Geologist and Tim Tonkin, District Landman at Danville Compressor Station, Boone County, West Virginia



Cabot's legacy asset position in the East continued to grow in 2006 as the reserves in the region increased to 704 Bcfe from 637 Bcfe in 2005. More importantly, the East region drilling program contributed over 88 Bcfe of new reserves, replacing 100 percent of Cabot's total production.

East Production *(Bcfe)*

2006	23.7
2005	21.6
2004	19.6

East Reserves *(Bcfe)*

2006	703.6
2005	637.4
2004	550.5

East Gross Wells Drilled

2006	200
2005	185
2004	171

Cabot's shale play in the East continued to gain momentum with over 50 percent of 2006 wells having a "shale" component. In addition to the benefit of being in a premium gas price market, the Company's Cranberry pipeline system interconnects with three major interstate pipelines, a variety of local distribution companies and numerous end users. This system provides flexibility to secure advantageous pricing and transportation resources for its customers. The production in this region is 99 percent natural gas weighted.

Cabot's legacy asset position in the East continued to grow in 2006 as reserves in the region increased to 704 Bcfe from 637 Bcfe in 2005. More importantly, the East region drilling program contributed over 88 Bcfe of new reserves, replacing 100 percent of Cabot's total production. This was accomplished while employing only 24 percent of the Company's total capital spending. In 2006, Cabot – through its Cranberry subsidiary – invested approximately $18 million in the East region infrastructure to provide additional capacity for the production increases from an expanding drilling program. This investment allows for the Company to maximize production from the approximately 270 wells it plans to drill in 2007, of which 165 will have a shale component. This represents a 72 percent increase over the 96 shale wells drilled in 2006.

Since 2002, when the Company began refocusing on its Appalachian properties, 698 wells have been drilled in the East region. The execution of this program would not have been possible without the dedicated efforts from Cabot employees. The region's Danville team (pictured on page 7) has added substantial value by executing an expanded program and identifying additional drilling opportunities in this district. In addition to drilling wells, these individuals completed the Henlawson pipeline project which allowed for the drilling of two significant leases previously underdeveloped. Since this project's completion, Cabot has drilled and completed over 60 wells in this area and successfully tied them into the Henlawson system.

The Pineville district is also a great success story. It has been the traditional growth area due to good conventional reserves and available expansion in the infrastructure. The Sissonville district, where the horizontal play has developed, has become a focal point for the Company in its effort to accelerate production and reserve realizations. In the last year, Cabot has worked to implement and improve a horizontal drilling technique for this region. Horizontal drilling provides the opportunity to access more reserves per well, accelerating the exploitation of reserve assets. While the horizontal program was developed to enhance production from the Devonian shale, the Company is looking at the opportunity to employ this technique in some other traditional reservoirs.

Cabot's West Virginia properties provide for organic growth with a drilling inventory of over 8,000 locations and a significant undeveloped acreage position. The estimated unrisked resource potential is 2.4 to 3.6 Tcfe. Cabot owns a 100 percent working interest in the majority of the areas it operates.

In preparing for increased levels of drilling, the Company has steadily invested in infrastructure, technology and employees in recent years. Cabot's facility engineers have performed exceptionally well by modeling existing and needed infrastructure, while successfully maximizing efficiencies. The Company is positioned to operate in an accelerated environment with the continued investment in people, infrastructure and organic drilling opportunity.

Gulf Coast

Since Cabot's strategic decision to invest in lower risk resources, the greatest transformation was successfully achieved in the Gulf Coast region. In 2002, the Company began its transition from investing and drilling in high-risk properties to securing and drilling properties characterized by a lower risk profile. By the end of 2006, a portfolio of lower risk, repeatable opportunities was successfully amassed in the region, which allowed for the timely divestiture of Cabot's south Louisiana and offshore properties.

Dawson #1 well in Minden field near Henderson, Texas. Left to right: Dan Houchin, Production Engineer; Robin Lancaster, Geologist; Dan Knight, Geologist and Tod Hensarling, Landman

In 2006, Cabot divested its south Louisiana and offshore properties, but not until new acreage positions were sufficient to replace production and cash flow coming from the region in a short time frame.

* The dashed line represents 3.3 Bcfe of production related to the asset sale that removed 68 Bcfe from the region.

The Gulf Coast region has contributed approximately 50 percent to total Company discretionary cash flow over the last five years. This robust contribution was supported by higher production rates and favorable pricing in the region. In 2006, Cabot divested its south Louisiana and offshore properties, but not until new acreage positions were sufficient to replace production and cash flow coming from the region in a short time frame. The divestiture is the result of the Company's decision to redirect investment to lower risk properties, reduce Cabot's baseline decline curve, and capture the premium price environment in the divestiture market for these types of assets. The Company's new portfolio in this region stretches from south Texas to north Louisiana and is all onshore.

Cabot continues to identify and invest in its focus areas, which include the Minden and County Line prospects located in east Texas, McCampbell and Raymondville fields in south Texas and Castor prospect in north Louisiana. The Company is active in the Cotton Valley, Hosston/Travis Peak, and James and Pettet formations in east Texas and north Louisiana. The team (pictured on page 11) has been instrumental in Cabot's ability to build the lower risk repeatable portfolio in east Texas and north Louisiana.

- East Texas – This year, the first horizontal well was successfully completed in the County Line prospect, located southeast of the Company's Minden field. Based upon this success, a significant drilling program has been designed for the region for 2007 in County Line utilizing horizontals. At Minden, Cabot has drilled over 40 wells to date with a 100 percent success rate. The Company has acquired approximately 11,000 net acres and has identified 200 to 250 potential locations in Minden. Three to four rigs have been working in Minden. This multi-rig drilling effort will progress throughout 2007 and will test the horizontal concept as well. Cabot owns 100 percent working interest in the majority of these areas in east Texas.
- South Texas – The Company's south Texas program includes drilling in the Raymondville and McCampbell fields. In 2006, Cabot drilled three wells in Raymondville, which contributed to the region's net daily production. The McCampbell field is a success due to the exceptional well design implemented in the region. The Company holds approximately 5,000 net acres in the field. In 2006, Cabot drilled 13 south Texas wells and plans to drill 15 in 2007. The Company owns greater than 90 percent working interest in its active areas of south Texas.
- North Louisiana – Cabot has drilled two successful wells in its Castor prospect in north Louisiana. These wells came on-line in December 2006 at a combined rate of 6.5 gross Mmcfe per day. Production from these wells is from the Hosston and Cotton Valley producing intervals. With the success from initial drilling, at least four additional wells are scheduled to be drilled in 2007 and an estimated 30 potential locations have been identified in the field. The Company controls 100 percent working interest in this prospect. Additionally, Cabot has plans for several other prospects in north Louisiana.

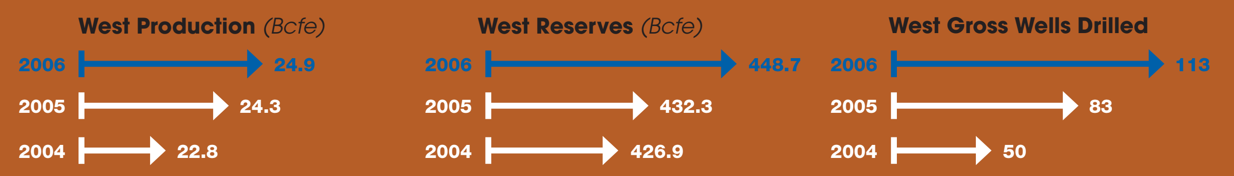
The Company drilled 64 wells in the Gulf Coast region in 2006 and plans to drill 50 to 75 in 2007. Cabot has significant opportunity for growth in this region with 600 to 700 locations identified and an estimated unrisked resource potential of 700 Bcfe to 1.0 Tcfe.

West Region and Canada

The West region is composed of two core areas – the Rocky Mountains, including Wyoming, Utah and Colorado, and the Mid-Continent area in Oklahoma, Kansas and the Texas Panhandle. Cabot has created a balance among an extensive down-spacing effort on the Moxa Arch, in the Rocky Mountains, stable growth with highly successful development in the Mid-Continent, and focused exploration in its Paradox Basin. In Canada, the effort is on exploiting recent exploration success.

Tom Belis, Geologist; Pat Tracy, Landman and Mark Kachmar, Reservoir Engineer share ideas in a Morrow team planning session for the Mid-Continent area.

Since 2003 when Cabot entered Canada on an organic growth platform, opportunities in the region have been identified in five core areas. These areas include Musreau, Hinton, Narraway, Smoky (Bolton) and Chime.



West includes Rocky Mountain and Mid-Continent areas only. (Canada is a separate region.)

In the Mid-Continent area, Cabot has several active development projects, including expansion of the Morrow and Chester plays. These Mid-Continent plays provide consistent and repeatable drilling results. Since re-emphasis in this area, the Company has had success in 106 of 111 wells drilled for a success rate of 95 percent. Cabot today owns a total of 265,000 gross acres (194,000 net) in the Mid-Continent area on which it continues to exploit and expand. The Company has identified 240 potential locations in the Mid-Continent, approximately 160 more than three years ago. Over the last two years, the efforts of the team (pictured on page 15) has established the Mid-Continent as a key growth area for the region. Cabot employees continue to produce strong results and represent an invaluable resource for the future. For example, since 2004, this team expanded the acreage position in Ellis County, Oklahoma, from 3,600 to over 25,000 net acres. The Company drilled 50 Mid-Continent wells in 2006 with a 96 percent success rate and plans to drill 53 wells in 2007.

Additionally, Cabot is pursuing an infill drilling program on the Moxa Arch in the Rocky Mountains. This 80-acre infill Frontier/Dakota program was implemented in 2006. The Company owns 187,000 gross acres (107,000 net) and drilled 35 wells with a 100 percent success rate in 2006. Based on the success of the 2006 program, an additional 40 to 50 wells in the Frontier/Dakota are included in the 2007 drilling program. The Dakota formation in this program provides upside. While more stratigraphic in nature, the Dakota can be prolific – as Cabot experienced in its Ballerina well where the Company had an initial production rate of over 8 Mmcfe per day. Cabot will continue to look for similar opportunities. Over 700 potential locations have been identified on the Company's Moxa Arch acreage. The majority of these locations are not recognized in Cabot's reserve bookings.

The Company maintains an exploratory drilling effort primarily in the Paradox Basin of Utah and Colorado. Last year, Cabot drilled three exploration and four development wells in the Paradox Basin. The results were mixed with two unsuccessful wells and one well being evaluated at year end in the exploration program. The Company experienced a 100 percent success rate in the development program. Four additional exploratory wells are planned in 2007. Cabot has 334,742 gross acres in the basin.

Canada

Canada provides the Company with grass roots focused exploration/exploitation with additional development upon success. Additionally, because of the Canadian system for developing fields, there exist many opportunities for down-spacing. This creates added upside to existing fields. Since 2003 when Cabot entered Canada on an organic growth platform, opportunities in the region have been identified in five core areas. These areas include Musreau, Hinton, Narraway, Smoky (Bolton) and Chime. The Company's position in Canada includes over 52,000 net acres with an unrisked resource potential of 225 to 275 Bcfe. Cabot drilled 10 gross wells in 2006 with planned drilling of 10 to 15 additional wells in 2007. Based on the Company's evaluation, approximately 226 drilling locations have been identified.

Musreau # 6-15 in Alberta, Canada pictured on opposite page.

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.

James G. Floyd
Former President, Chief Executive Officer and Director, The Houston Exploration Company

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
James G. Floyd
Robert Kelley

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

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

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

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, 2006**

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 [ ].

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer" and "large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer_X_ Accelerated filer___ Non-accelerated filer___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).

Yes___ No_X_

The aggregate market value of Common Stock, par value $.10 per share ("Common Stock"), held by non-affiliates (based upon the closing sales price on the New York Stock Exchange on June 30, 2006), as of the last business day of registrant's most recently completed second fiscal quarter was approximately $2.4 billion.

As of January 31, 2007, there were 48,329,613 shares of Common Stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held May 2, 2007 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, 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, we have four regional offices located in Houston, Texas; Charleston, West Virginia; Denver, Colorado; and Calgary, Alberta.

Net income for 2006 of $321.2 million, or $6.64 per share, exceeded the prior year's net income of $148.4 million, or $3.04 per share, by $172.8 million, or 116% over the prior year net income. The year-over-year net income increase was achieved primarily due to the recognition of a gain of $231.2 million ($144.5 million, net of tax) in 2006 related to the disposition of our offshore and certain south Louisiana properties, along with higher realized natural gas and crude oil production revenues as a result of more favorable settlements of production hedges on natural gas and increases in crude oil prices. These increases were partially offset by higher operating expenses of $41.0 million between 2005 and 2006. Higher operating expenses were principally due to increased depreciation, depletion and amortization costs, general and administrative expenses, and direct operations expenses. In addition, income tax expenses increased by $101.5 million primarily as a result of the gain on the disposition of properties discussed above. At December 31, 2006, our debt-to-total-capital ratio was 20%, down from 36% at the end of 2005.

Operating Revenues increased by $79.2 million, or 12%, over the prior year due to increased natural gas production as well as strong realized commodity prices. Natural gas production revenues increased by $68.9 million, or 14%, over the prior year due to increased natural gas production in all regions as well as higher realized natural gas prices. Crude oil and condensate revenues increased by $9.0 million, or 11%, over the prior year due primarily to an increase in crude oil prices. Somewhat offsetting the crude oil price increase was the decrease in crude oil production of approximately 19% in 2006. Both of these increases were net of the effect of the loss of production due to the sale of our offshore and certain south Louisiana properties at the end of the third quarter of 2006. In addition, crude oil revenues for 2005 included an unrealized gain on crude oil derivatives of $5.5 million, and there was no unrealized impact in 2006. Brokered natural gas revenues decreased by $4.9 million due to a decrease in sales price partially offset by an increase in brokered volumes.

In 2006, energy commodity prices remained strong throughout the year. Our 2006 realized natural gas price was $7.13 per Mcf, six percent higher than the 2005 realized price of $6.74. Our realized crude oil price was $65.03 per Bbl, 47% higher than the 2005 realized price of $44.19. These realized prices include the realized impact of derivative instruments (costless 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. The continued strength in the forward curve above historical levels and our receivable hedge position allowed us to pursue our largest organic capital program ever in 2006. This program included a significant level of drilling and investment in new leaseholds for the future. While operating cash flow for the year did not cover this capital program, the proceeds from the sale of assets allowed us to fund our investment plans. We believe that as a result of the activity in 2006, we have the financial and operational flexibility to take advantage of opportunities as they arise.

On an equivalent basis, our production level in 2006 increased by five percent from 2005. We produced 88.2 Bcfe, or 241.7 Mmcfe per day, in 2006, as compared to 84.4 Bcfe, or 231.1 Mmcfe per day, in 2005. Natural gas production increased to 79.7 Bcf in 2006 from 73.9 Bcf in 2005, with increases in natural gas production occurring in all regions. This growth primarily resulted from our 2005 and 2006 drilling programs, which focused on projects in basins traditionally known for gas development. Highlights included the East region, the Minden field in the Gulf Coast and Canada. This natural gas production increase includes the effects of the divestiture of our offshore and certain south Louisiana properties. Oil production decreased by 334 Mbbls from 1,739 Mbbls in 2005 to 1,405 Mbbls in 2006 due primarily to a decrease in production in the Gulf Coast region resulting from the continued natural decline of the CL&F lease in south Louisiana as well as the sale in September 2006 of this lease and other offshore and certain south Louisiana properties.

A portion of our production was covered by oil and gas hedge instruments throughout 2006. Again during 2006 as in 2005, we employed the use of collars to hedge our price exposure on our production. For 2006, collars covered 34% of the natural gas production and had a weighted average floor of $8.25 per Mcf and a weighted average ceiling of $12.74 per Mcf. At December 31, 2006, approximately 49% of the anticipated 2007 natural gas production is hedged with a weighted average floor of $8.99 per Mcf and a weighted average ceiling of $12.19 per Mcf. For 2006, collars covered 26% of the crude oil production with an average floor of $50.00 per Bbl and an average ceiling of $76.00 per Bbl. At December 31, 2006, approximately 47% of our anticipated crude oil production is hedged for 2007 with a weighted average floor of $60.00 per Bbl and a weighted average ceiling of $80.00 per Bbl. As of December 31, 2006, no derivatives are in place for 2008. Our decision to hedge 2007 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. With greater volumes hedged for 2007 than in 2006 and hedged levels at higher prices, the market would have to soften considerably for us not to match 2006 realized prices in 2007.

For the year ended December 31, 2006, we drilled 387 gross wells with a success rate of 96% compared to 316 gross wells with a success rate of 95% for the prior year. In 2007, we plan to drill approximately 440 gross wells.

Our 2006 capital and exploration spending was $537.5 million compared to $425.6 million of total capital and exploration spending in 2005. Total 2005 capital and exploration spending included $73.1 million, primarily in the Gulf Coast, to acquire proved producing properties. 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. In 2006, we allocated our planned program for capital and exploration expenditures among our various operating regions, and we plan to continue to do so in 2007. For 2007, the East region will start the year with the largest allocation of capital, followed by the Gulf Coast, the West and Canada. This is the first time since 1997 that the Gulf Coast is not the leading capital allocation recipient. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long term. In 2007, we plan to spend approximately $434 million on capital and exploration activities.

Our proved reserves totaled approximately 1,416 Bcfe at December 31, 2006, of which 97% was natural gas. This reserve level was up by six percent from 1,331 Bcfe at December 31, 2005 on the strength of results from our drilling program and the increase in our capital spending. The reserve levels set forth below reflect the impact of approximately 68 Bcfe of proved reserves at December 31, 2005 associated with the offshore and certain south Louisiana properties sold at the end of the third quarter of 2006.

The following table presents certain reserve, production and well information as of December 31, 2006.

			West				
	East	Gulf Coast	Rocky Mountains	Mid-Continent	Total	Canada	**Total**
Proved Reserves at Year End *(Bcfe)*							
Developed	491.5	153.9	193.8	168.1	361.9	24.9	**1,032.2**
Undeveloped	212.1	81.3	62.2	24.6	86.8	3.7	**383.9**
Total	**703.6**	**235.2**	**256.0**	**192.7**	**448.7**	**28.6**	**1,416.1**
Average Daily Production *(Mmcfe per day)*	64.9	101.2	37.9	30.4	68.3	7.3	**241.7**
Reserve Life Index *(In years)* (1)	29.7	6.4	18.5	17.4	18.0	10.8	**16.1**
Gross Wells	2,926	566	638	728	1,366	28	**4,886**
Net Wells (2)	2,719.4	380.4	281.2	502.6	783.8	8.2	**3,891.8**
Percent Wells Operated *(Gross)*	96.8%	77.4%	49.8%	76.4%	64.0%	53.6%	**85.1%**

(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.

SALE OF PROPERTIES

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. The properties sold included proved reserves of approximately 98 Bcfe, as of the August 1, 2006 effective date, including 68 Bcfe of proved reserves recorded as of December 31, 2005, and had average daily production for the first nine months of 2006 of 47.4 Mmcfe.

Pursuant to the asset purchase agreement for the sale, dated August 25, 2006, the gross sales price was offset by the net cash flow from operation of the properties from August 1, 2006 through the closing date and other purchase price adjustments. The net proceeds from the sale were used to add funding to our capital program, repurchase shares of common stock, repay outstanding debt under the revolving credit facility and pay taxes related to the transaction. Also pursuant to the agreement, we entered into certain commodity price swaps on behalf of Phoenix. At closing on September 29, 2006, these derivative instruments were assigned to Phoenix, and we were released from all rights and obligations with respect thereto. There was no ultimate impact on our financial statements due to the existence of these swaps.

Through December 31, 2006, the Company had received approximately $327.5 million in net proceeds from the sale, which reflects the $340.0 million gross sales price, reduced by purchase price adjustments of $4.0 million as well as amounts attributable to consents and preferential rights expected to be settled in the first quarter of 2007 of $8.5 million. A net gain of $231.2 million ($144.5 million, net of tax) was recorded in the Consolidated Statement of Operations in 2006 and an additional gain of approximately $12 million is expected to be recognized in the first quarter of 2007 in connection with the closing of certain property sales to Phoenix for which third party consents (including deferred amounts) had not been obtained as of December 31, 2006 and sales to other parties that exercised their contractual preferential rights. This gain will be subject to customary purchase price adjustments.

EAST REGION

Our East activities are concentrated primarily in 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 2006 and 2005, respectively, were $145.4 million, or 27% of our total 2006 capital and exploration expenditures, and $99.0 million, or 23% of our total 2005 capital and exploration expenditures. Of the total company year-over-year increase in capital and exploration expenditures, 42% was attributable to an increase in the East region spending. For 2007, we have budgeted approximately $160 million for capital and exploration expenditures in the region.

At December 31, 2006, we had 2,926 wells (2,719.4 net), of which 2,833 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 9,300 feet, with an average depth of approximately 3,750 feet. Average net daily production in 2006 was 64.9 Mmcfe. 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 reserves is relatively long. At December 31, 2006, we had 703.6 Bcfe of proved reserves (substantially all natural gas) in the East region, constituting 50% of our total proved reserves. This region is managed from our office in Charleston, West Virginia.

In 2006, we drilled 200 wells (190.7 net) in the East region, of which 197 wells (188.0 net) were development wells. In 2007, we plan to drill approximately 270 wells.

In 2006, we produced and marketed approximately 65 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 2,700 miles of pipeline with interconnects to three interstate transmission systems, seven local distribution companies and numerous end users as of the end of 2006. 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 65% 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 north Louisiana and in south and east Texas. A regional office in Houston manages the operations. Principal producing intervals are in the Cotton Valley and Hosston formations in north Louisiana and east Texas and the Frio, Vicksburg and Wilcox formations in south Texas at depths ranging from 2,200 to 17,000 feet, with an average depth of approximately 9,600 feet. Capital and exploration expenditures were $234.8 million for 2006, or 44% of our total 2006 capital and exploration expenditures, and $233.5 million for 2005, or 55% of our total 2005 capital and exploration expenditures. For 2007, we have budgeted approximately $135 million for capital and exploration expenditures in the region. Our 2007 Gulf Coast drilling program will emphasize activity in our focus areas of east Texas, north Louisiana and south Texas.

In 2006, we drilled 64 wells (50.8 net) in the Gulf Coast region, of which 52 wells (41.4 net) were development and extension wells. In 2007, we plan to drill 51 wells. We had 566 wells (380.4 net) in the Gulf Coast region as of December 31, 2006, of which 438 wells are operated by us. Average daily production in 2006 was 101.2 Mmcfe. At December 31, 2006, we had 235.2 Bcfe of proved reserves (89% natural gas) in the Gulf Coast region, which represented 16% of our total proved reserves.

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 2006, we produced and marketed approximately 3,177 barrels of crude oil/condensate per day in the Gulf Coast region at market responsive prices.

WEST REGION

Our activities in the West region are managed by a regional office in Denver, Colorado. At December 31, 2006, we had 448.7 Bcfe of proved reserves (96% natural gas) in the West region, constituting 32% of our total proved reserves.

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, 2006, we had 256.0 Bcfe of proved reserves (95% natural gas) in the Rocky Mountains area, or 18% of our total proved reserves. Capital and exploration expenditures in the Rocky Mountains were $66.2 million for 2006, or 12% of our total 2006 capital and exploration expenditures, and $45.4 million for 2005, or 11% of our total 2005 capital and exploration expenditures. For 2007, we have budgeted approximately $59 million for capital and exploration expenditures in the area.

We had 638 wells (281.2 net) in the Rocky Mountains area as of December 31, 2006, of which 318 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 4,500 to 14,200 feet, with an average depth of approximately 10,950 feet. Average net daily production in the Rocky Mountains during 2006 was 37.9 Mmcfe.

In 2006, we drilled 63 wells (27.6 net) in the Rocky Mountains, of which 61 wells (25.9 net) were development wells. In 2007, we plan to drill 55 wells.

Mid-Continent

Our Mid-Continent activities are concentrated in the Anadarko Basin in southwest Kansas, Oklahoma and the panhandle of Texas. Capital and exploration expenditures were $39.8 million for 2006, or seven percent of our total 2006 capital and exploration expenditures, and $23.7 million for 2005, or six percent of our total 2005 capital and exploration expenditures. For 2007, we have budgeted approximately $43 million for capital and exploration expenditures in the area.

As of December 31, 2006, we had 728 wells (502.6 net) in the Mid-Continent area, of which 556 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 2006 was 30.4 Mmcfe. At December 31, 2006, we had 192.7 Bcfe of proved reserves (97% natural gas) in the Mid-Continent area, or 14% of our total proved reserves.

In 2006, we drilled 50 wells (32.5 net) in the Mid-Continent, all of which were development and extension wells. In 2007, we plan to drill 53 wells.

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 75% 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 23% of the natural gas production is sold under short-term arrangements at index-based prices, and the remaining two 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 2006, we produced and marketed approximately 573 barrels of crude oil/condensate per day in the West region at market responsive prices.

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 Provinces of Alberta and British Columbia. At December 31, 2006, we had 28.6 Bcfe of proved reserves (98% natural gas) in the Canada region, constituting two percent of our total proved reserves.

Capital and exploration expenditures in Canada were $49.0 million for 2006, or nine percent of our total 2006 capital and exploration expenditures, and $22.9 million for 2005, or five percent of our total 2005 capital and exploration expenditures. For 2007, we have budgeted approximately $35 million for capital and exploration expenditures in the area.

We had 28 wells (8.2 net) in the Canada region as of December 31, 2006, of which 15 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 9,500 to 12,000 feet. Average net daily production in Canada during 2006 was 7.3 Mmcfe.

In 2006, we drilled 10 wells (5.4 net) in Canada, of which 7 wells (3.6 net) were development and extension wells. In 2007, we plan to drill 11 wells.

In 2006, we produced and marketed approximately 32 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 2006 we employed natural gas and crude oil price collar agreements 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. In 2005, we employed natural gas and crude oil price collars along with natural gas and crude oil price swap agreements. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place. At December 31, 2006, we have natural gas and crude oil price collar arrangements in place for 2007.

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, 2006.

	Natural Gas *(Mmcf)*			Liquids [1] *(Mbbl)*			Total [2] *(Mmcfe)*		
	Developed	Undeveloped	Total	Developed	Undeveloped	Total	Developed	Undeveloped	**Total**
East	488,790	212,107	700,897	456	—	456	491,528	212,107	**703,635**
Gulf Coast	137,250	71,337	208,587	2,782	1,654	4,436	153,941	81,259	**235,200**
Rocky Mountains	184,156	59,934	244,090	1,600	383	1,983	193,753	62,234	**255,987**
Mid-Continent	162,202	24,409	186,611	984	40	1,024	168,109	24,646	**192,755**
Canada	24,452	3,656	28,108	73	1	74	24,891	3,661	**28,552**
Total	**996,850**	**371,443**	**1,368,293**	**5,895**	**2,078**	**7,973**	**1,032,222**	**383,907**	**1,416,129**

(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 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 2006, we filed estimates of our oil and gas reserves for the year 2005 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 2006. If we had considered the impact of our hedging activities, which were in a receivable position at December 31, 2006, 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—Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated” 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, 2003	**1,069,484**	**12,103**	**1,142,108**
Revision of Prior Estimates	(7,850)	185	(6,739)
Extensions, Discoveries and Other Additions	140,986	1,074	147,426
Production	(72,833)	(2,002)	(84,847)
Purchases of Reserves in Place	5,384	24	5,525
Sales of Reserves in Place	(1,090)	—	(1,090)
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**
Proved Developed Reserves			
December 31, 2003	812,280	9,405	868,712
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**

(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,		
	2006	2005	2004
Net Wellhead Sales Volume			
Natural Gas *(Bcf)*			
East	**23.5**	21.4	19.4
Gulf Coast	**30.0**	28.1	31.3
West	**23.6**	23.2	21.9
Canada	**2.6**	1.2	0.2
Crude/Condensate/Ngl *(Mbbl)*			
East	**24**	27	27
Gulf Coast	**1,164**	1,530	1,809
West	**214**	172	163
Canada	**13**	18	3
Produced Natural Gas Sales Price *($/Mcf)* (1)			
East	**$ 7.99**	$ 8.02	$ 5.60
Gulf Coast	**7.37**	6.38	5.27
West	**6.05**	6.00	4.75
Canada	**6.18**	6.79	4.69
Weighted Average	**7.13**	6.74	5.20
Crude/Condensate Sales Price *($/Bbl)* (1)	**$ 65.03**	$ 44.19	$ 31.55
Production Costs *($/Mcfe)* (2)	**$ 1.31**	$ 1.23	$ 0.99

(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).

(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, 2006. 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	204,594	131,896	220,862	145,949
Kansas	29,067	27,745	0	0	29,067	27,745
Louisiana	8,367	6,189	52,652	51,427	61,019	57,616
Mississippi	0	0	565,916	322,095	565,916	322,095
Montana	397	210	9,982	9,085	10,379	9,295
New York	2,379	961	621	256	3,000	1,217
Ohio	6,260	2,384	20,152	18,963	26,412	21,347
Oklahoma	176,303	122,978	23,334	15,912	199,637	138,890
Pennsylvania	111,496	63,549	19,213	19,148	130,709	82,697
Texas	108,748	75,082	41,350	26,884	150,098	101,966
Utah	2,820	1,609	191,404	99,412	194,224	101,021
Virginia	22,298	20,201	2,854	1,770	25,152	21,971
West Virginia	591,571	558,578	297,758	276,661	889,329	835,239
Wyoming	139,103	72,034	273,704	152,638	412,807	224,672
Total	**1,217,058**	**965,998**	**1,708,925**	**1,130,112**	**2,925,983**	**2,096,110**

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	97,455	79,488	51,603	49,671	149,058	129,159
Total	**132,743**	**112,071**	**65,051**	**52,596**	**197,794**	**164,667**
Aggregate Total	**1,349,801**	**1,078,069**	**1,773,976**	**1,182,708**	**3,123,777**	**2,260,777**

Canada Leasehold Acreage by Province

	Developed		Undeveloped		Total	
	Gross	Net	Gross	Net	Gross	Net
Alberta	8,320	3,627	99,931	34,099	108,251	37,726
British Columbia	700	280	11,988	4,730	12,688	5,010
Saskatchewan	0	0	9,903	9,903	9,903	9,903
Total	**9,020**	**3,907**	**121,822**	**48,732**	**130,842**	**52,639**

Total Net Leasehold Acreage by Region of Operation

	Developed	Undeveloped	Total
East	645,673	316,798	962,471
Gulf Coast	54,419	404,243	458,662
West	265,906	409,071	674,977
Canada	3,907	48,732	52,639
Total	**969,905**	**1,178,844**	**2,148,749**

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, 2006. The figures below assume no future successful development or renewal of undeveloped acreage.

	2007	2008	2009
East	52,924	33,405	24,494
Gulf Coast	49,242	18,907	5,601
West	68,998	158,124	47,164
Canada	19,781	11,856	4,289
Total	**190,945**	**222,292**	**81,548**

Well Summary

The following table presents our ownership at December 31, 2006, 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 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	2,901	2,707.4	25	12.0	2,926	2,719.4
Gulf Coast	455	278.0	111	102.4	566	380.4
West	1,311	749.6	55	34.2	1,366	783.8
Canada	28	8.2	0	0.0	28	8.2
Total	**4,695**	**3,743.2**	**191**	**148.6**	**4,886**	**3,891.8**

(1) Total does not include service wells of 50 (49.0 net).

Drilling Activity

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

	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**

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, particularly in the West and Gulf Coast regions and Canada.

OTHER BUSINESS MATTERS

Major Customer

In 2006, no customer accounted for more than 10% of our total sales. In each of 2005 and 2004, 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, and the FERC has been directed to establish new regulations that are intended to increase natural gas pricing transparency through, among other things, expanded dissemination of information about the availability and prices of gas sold. 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. In December 2006, Congress enacted the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006, which reauthorizes the programs adopted under the 2002 Act, proposes enhancements for state programs to reduce excavation damage to pipelines, establishes increased federal enforcement of one-call excavation programs, and establishes a new program for review of pipeline security plans and critical facility inspections. In addition, beginning in October 2005, the DOT's Pipeline and Hazardous Materials Safety Administration commenced a rulemaking proceeding to develop rules that would better distinguish onshore gathering lines from production facilities and transmission lines, and to develop safety requirements better tailored to gathering line risks. On March 15, 2006, the DOT revised its regulations to define more clearly the categories of gathering facilities subject to DOT regulation, establish new safety rules for certain gathering lines in rural areas, revise the current regulations applicable to safety and inspection of gathering lines in non-rural areas, and adopt new compliance deadlines. We are not able to predict with certainty the final outcome of these new 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-yearly 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, 2006, we had 374 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.

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 2006, 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 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.

Reserve estimates depend on many assumptions that may prove to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions could cause the quantities and net present value of our reserves to be overstated.

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 uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysic, engineering and production data. As a result, estimates of different engineers may vary. In addition, the extent, quality and reliability of this technical data can vary. The degree of uncertainty varies among the four regions in which we operate. The estimation of reserves for certain properties sold in 2006 as well as a small number of properties currently held in the Gulf Coast region requires more estimates than in Canada and the East and West regions and inherently has more uncertainty surrounding reserve estimation. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. 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. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

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.

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, 2006, we owned or operated approximately 2,900 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.

In accordance with customary industry practice, 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. 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, particularly in the Rocky Mountains, Mid-Continent, Canada and Gulf Coast areas. 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 2006 we primarily employed natural gas and crude oil price collar agreements to attempt to manage price risk. 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. In addition, we employed natural gas and crude oil price swap agreements during 2005. The price swaps call for payments to, or receipts from, counterparties based on whether the market price of natural gas or crude oil for the period is greater or less than the fixed price established for that period when the swap is put in place.

These hedging arrangements limit the benefit to us of increases in prices. In addition, these arrangements expose us to risks of financial loss in a variety of circumstances, including when:

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

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

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

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

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

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

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 have requested class certification and allege 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.

Discovery and pleadings necessary to place the class certification issue before the state court have been ongoing. The Court entered an order on June 1, 2005 granting the motion for class certification. The parties have negotiated a modification to the order which will result in the dismissal of the claims related to the gas sales contract settlement in connection with the Columbia Gas Transmission bankruptcy proceedings and that will limit the claims to those arising on and after December 17, 1991. The Court postponed the trial date from April 17, 2006, in light of the case involving an unrelated party pending before the West Virginia Supreme Court of Appeals described below. We intend to challenge the class certification order by filing a Petition for Writ of Prohibition with the West Virginia Supreme Court of Appeals.

The West Virginia Supreme Court of Appeals issued a decision in 2006 in a case against another producer (the Tawney case) that raised some of the same issues as are raised in our case. This recent decision may negatively impact some of the defenses we have raised in our litigation with respect to the issue of deductibility of post-production expenses under certain leases, but we believe that in a significant number of leases we have lease language, factual distinctions and defenses that are not implicated by the ruling.

The Tawney case involves claims concerning the deductibility of post-production expenses and the failure to properly inform, issues shared with our case, but also involves additional claims not raised in our case. The most significant additional claims are related to sales under long-term, fixed-price agreements at prices considered significantly below market value, as well as claims for certain volume reductions and unmetered production. The Tawney case went to trial in January 2007, and the jury returned a verdict against the producer for $130 million in compensatory damages and $270 million in punitive damages. Judgment has not yet been entered in the Tawney case, and an appeal is expected. We are closely monitoring developments in the Tawney case, and we continue to investigate how this recent ruling may impact our defense of our case. The case against us has been re-activated to the docket and trial is set for August 13, 2007.

We are vigorously defending the case. A reserve has been established that management believes is adequate based on its estimate of the probable outcome of this case.

Texas Title Litigation

On January 6, 2003, we were served with Plaintiffs' Second Amended Original Petition in Romeo Longoria, et al. v. Exxon Mobil Corporation, et al. in the 79th Judicial District Court of Brooks County, Texas. Plaintiffs filed their Second Supplemental Original Petition on November 12, 2004 and their Third Supplemental Original Petition on February 22, 2005 (which added Wynn-Crosby 1996, Ltd. and Dominion Oklahoma Texas Exploration & Production, Inc.). Plaintiffs filed their Third Amended Original Petition on February 21, 2006, which incorporated all prior supplemental petitions. Plaintiffs allege that they are the owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. Cody Energy, LLC, our subsidiary, acquired certain leases and wells in 1997 and 1998.

The plaintiffs allege that they are entitled to be declared the rightful owners of an undivided interest in minerals and all improvements on the lands on which we acquired these leases. The plaintiffs also assert claims for trespass to try title, action to remove a cloud on the title, failure to properly account for royalty, fraud, trespass and conversion, all for unspecified actual and exemplary damages. Plaintiffs claim that they acquired title to the property by adverse possession. Plaintiffs also assert the discovery rule and a claim of fraudulent concealment to avoid the affirmative defense of limitations. In August 2005, the case was abated until late February 2006, during which time the parties were allowed to amend pleadings or add additional parties to the litigation. Plaintiffs did not join additional parties by the abatement deadline. Defendants, including us, re-urged our motion to dismiss, and on April 5, 2006, the Court granted the motion, dismissing the oil company defendants, without prejudice. Because all defendants were not dismissed at that time, the order dismissing us was not then final. A motion to finalize the proceedings in the trial court via severance of the dismissed defendants was filed April 25, 2006, and the remaining defendants moved to join the motions that led to the dismissal of us. In 2006, the Court dismissed the claims. Plaintiffs have filed a Notice of Appeal. Although the record is not yet complete and, therefore, specific appellate deadlines have not been set, we expect that, following briefing and oral argument, the appellate court will issue its decision by the end of 2007 or early 2008.

Raymondville Area

In April 2004, our wholly owned subsidiary, Cody Energy, LLC, filed suit in state court in Willacy County, Texas against certain of our co-working interest owners in the Raymondville Area, located in Kenedy and Willacy Counties. In early 2003, we had proposed a new prospect under the terms of the Joint Operating Agreement. Some of the co-working interest owners elected not to participate. The initial well was successful and subsequent wells have been drilled to exploit the discovery made in the first well.

The working interest owners who elected not to participate notified us that they believed that they had the right to participate in wells drilled after the initial well. We contend that the working interest owners that elected not to participate are required to assign their interest in the prospect to those who elected to participate. The defendants filed a counter claim against us, and one of the defendants filed a lien against our interest in the leases in the Raymondville Area.

We have signed a settlement agreement with certain of the defendants representing approximately three percent of the interest in the area. Cody and the remaining defendant filed cross motions for summary judgment. In August 2005, the trial judge entered an order granting our Motion for Summary Judgment requiring the remaining defendant to assign to us all of its interest in the prospect and to remove the lien filed against our interest.

On July 12, 2006, we entered into a Purchase and Sale Agreement to acquire all of the defendant's interest in the Raymondville Field. The agreement would make the summary judgment ruling by the trial judge a final order, dismiss, with prejudice, all pending counter claims filed by such defendant and remove the lien against our properties filed by such defendant. We completed the acquisition in the third quarter of 2006. The lien has been removed, the summary judgment has become a final order and all of the defendant's claims have been dismissed.

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 $9.1 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 2006.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table shows certain information as of February 16, 2007 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	53	Chairman, President and Chief Executive Officer	2001
Michael B. Walen	58	Senior Vice President, Chief Operating Officer	1998
Scott C. Schroeder	44	Vice President and Chief Financial Officer	1997
J. Scott Arnold	53	Vice President, Land and Associate General Counsel	1998
Robert G. Drake	59	Vice President, Information Services and Operational Accounting	1998
Abraham D. Garza	60	Vice President, Human Resources	1998
Jeffrey W. Hutton	51	Vice President, Marketing	1995
Thomas S. Liberatore	50	Vice President, Regional Manager, East Region	2003
Lisa A. Machesney	51	Vice President, Managing Counsel and Corporate Secretary	1995
Henry C. Smyth	60	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 28, 2005, we announced that our Board of Directors had declared a 3-for-2 split of our 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, we paid cash based on the closing price of the common stock on the record date. All common stock accounts and per share data, including cash dividends per share, have been retroactively adjusted to give effect to the 3-for-2 split of our common stock.

		High	Low	Dividends
2006				
	First Quarter	**$ 52.01**	**$ 43.18**	**$ 0.04**
	Second Quarter	**54.44**	**38.42**	**0.04**
	Third Quarter	**55.15**	**44.15**	**0.04**
	Fourth Quarter	**65.71**	**44.38**	**0.04**
2005				
	First Quarter	$ 38.04	$ 27.78	$ 0.027
	Second Quarter	38.13	28.29	0.04
	Third Quarter	50.81	36.05	0.04
	Fourth Quarter	51.54	40.48	0.04

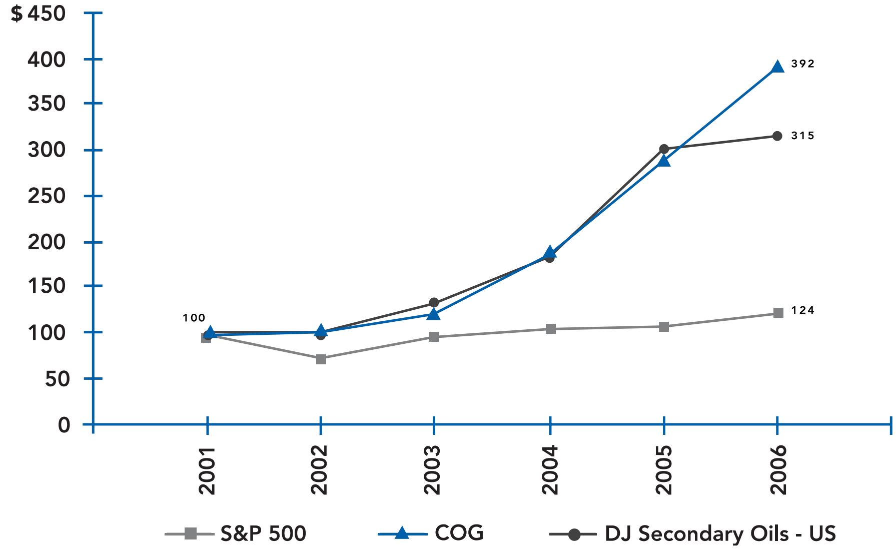
As of January 31, 2007, there were 590 registered holders of the common stock. Shareholders include individuals, brokers, nominees, custodians, trustees, and institutions such as banks, insurance companies and pension funds. Many of these hold large blocks of stock on behalf of other individuals or firms.

Issuer Purchases of Equity Securities

On August 13, 1998, we announced that our Board of Directors authorized the repurchase of two million shares of our common stock in the open market or in negotiated transactions. As a result of the 3-for-2 stock split effected in March 2005, this figure has been adjusted to three million shares. On October 26, 2006, we announced that our Board of Directors increased the number of shares of our common stock authorized for repurchase by an additional two million shares. All purchases executed have been through open market transactions. There is no expiration date associated with the authorization to repurchase our securities. We did not repurchase any shares under the program in the fourth quarter of 2006. As of December 31, 2006, 2,397,650 shares remained authorized for repurchase under the plan.

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 Secondary Oils-US Index for the period December 2001 through December 2006. The graph assumes that the value of the investment in our common stock and in each index was $100 on December 31, 2001 and that all dividends were reinvested.



Calculated Values	2001	2002	2003	2004	2005	**2006**
S&P 500	100.0	76.6	96.9	105.6	108.7	**123.5**
COG	100.0	104.1	124.4	189.1	290.6	**392.2**
DJ Secondary Oils-US	100.0	100.8	130.4	183.2	300.6	**314.6**

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

ITEM 6. SELECTED FINANCIAL DATA

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

	Year Ended December 31,				
(In thousands, except per share amounts)	**2006**	2005	2004	2003	2002
Statement of Operations Data					
Operating Revenues	**$ 761,988**	$ 682,797	$ 530,408	$ 509,391	$ 353,756
Impairment of Oil and Gas Properties [1]	**3,886**	—	3,458	93,796	2,720
Gain / (Loss) on Sale of Assets [2]	**232,017**	74	(124)	12,173	244
Income from Operations	**528,946**	258,731	160,653	66,587	49,088
Net Income	**321,175**	148,445	88,378	21,132	16,103
Basic Earnings per Share [3][4]	**$ 6.64**	$ 3.04	$ 1.81	$ 0.44	$ 0.34
Dividends per Common Share [3]	**$ 0.160**	$ 0.147	$ 0.107	$ 0.107	$ 0.107
Balance Sheet Data					
Properties and Equipment, Net	**$ 1,480,201**	$ 1,238,055	$ 994,081	$ 895,955	$ 971,754
Total Assets	**1,834,491**	1,495,370	1,210,956	1,055,056	1,100,947
Current Portion of Long-Term Debt	**20,000**	20,000	20,000	—	—
Long-Term Debt	**220,000**	320,000	250,000	270,000	365,000
Stockholders' Equity	**945,198**	600,211	455,662	365,197	350,657

(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 2006 reflects $231.2 million related to the sale of offshore and certain south Louisiana properties in the third quarter of 2006.

(3) All Earnings per Share and Dividends per Common Share figures have been retroactively adjusted for 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 $0.14 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 constantly compete for available capital: drilling opportunities, acquisition opportunities and financial opportunities such as debt repayment or repurchase of common stock. 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 2005 and 2006, the futures market reported strong natural gas and crude oil contract prices. Our realized natural gas and crude oil price was $7.13 per Mcf and $65.03 per Bbl, respectively, in 2006. 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 2005 to 2006.

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, natural gas liquids and crude oil prices, and therefore, we cannot determine 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 2005 and 2006. "Index" represents the first of the month Henry Hub index price per Mmbtu. The "2005" and "2006" 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 – 2006

(In $ per Mcf)	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**

Natural Gas Prices by Month – 2005

(In $ per Mcf)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 6.21	$ 6.29	$ 6.30	$ 7.33	$ 6.77	$ 6.13	$ 6.98	$ 7.65	$10.97	$13.93	$13.85	$11.21
2005	**$ 5.78**	**$ 5.84**	**$ 5.52**	**$ 6.28**	**$ 6.19**	**$ 5.55**	**$ 6.05**	**$ 6.58**	**$ 7.76**	**$ 8.94**	**$ 8.53**	**$ 7.78**

Prices for crude oil have continued to maintain strength in 2005 and rose further in 2006. The tables below contain the NYMEX monthly average crude oil price (Index) and our realized per barrel (Bbl) crude oil prices by month for 2005 and 2006. The "2005" and "2006" 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 – 2006

(In $ per Bbl)	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**

Crude Oil Prices by Month – 2005

(In $ per Bbl)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Index	$ 46.85	$ 48.05	$ 54.63	$ 53.22	$ 49.87	$ 56.42	$ 59.03	$ 64.99	$ 65.55	$ 62.27	$ 58.34	$ 59.45
2005	**$ 38.18**	**$ 40.57**	**$ 47.30**	**$ 44.95**	**$ 41.88**	**$ 44.58**	**$ 46.24**	**$ 46.62**	**$ 45.05**	**$ 45.92**	**$ 45.59**	**$ 43.70**

We reported earnings of $6.64 per share, or $321.2 million, for 2006. This is up from the $3.04 per share, or $148.4 million, reported in 2005. Earnings increased from 2005 to 2006 due to the $231.2 million ($144.5 million, net of tax) gain recorded in 2006 related to the sale of our offshore and certain south Louisiana properties. In addition, the stronger price environment, favorable natural gas hedge settlements and increased natural gas production were primary contributors to the earnings increase due to the increase in natural gas and oil revenues. Prices, including the realized impact of derivative instruments, rose six percent for natural gas and 47% for oil.

We drilled 387 gross wells with a success rate of 96% in 2006 compared to 316 gross wells with a 95% success rate in 2005. Total capital and exploration expenditures increased by $111.9 million to $537.5 million in 2006, of which $6.7 million was for property acquisitions, compared to $425.6 million in 2005, of which $73.1 million was for property acquisitions. We believe our operating cash flow in 2007 will be sufficient to fund a substantial portion of our budgeted capital and exploration spending of approximately $434 million, with minimal borrowings from our credit facility.

Our 2007 strategy will remain consistent with 2006. We will 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. In the current year we have allocated our planned program for capital and exploration expenditures among our various operating regions. We believe these strategies are appropriate in the current industry environment and will continue to add shareholder value over the long term.

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

FINANCIAL CONDITION

Capital Resources and Liquidity

Our primary sources of cash in 2006 were from funds generated from the sale of natural gas and crude oil production and proceeds from the sale of our offshore and certain south Louisiana properties and, to a lesser extent, proceeds from the exercise of stock options under our stock plans. 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. Working capital is also substantially influenced by these variables. During 2005, approximately 1.4 Bcfe of expected production in our Gulf Coast region was deferred due to the impacts of Hurricanes Katrina and Rita. These hurricanes did not have a material adverse impact on our capital resources nor liquidity. Fluctuation 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. Cash flows provided by operating activities were primarily used to fund exploration and development expenditures and to pay dividends. Proceeds from the disposition of our offshore and certain south Louisiana properties were used to fund additional capital expenditures, reduce borrowings under our revolving credit facility and to purchase treasury stock. Proceeds from the exercise of stock options under stock option plans and the tax benefit of stock based compensation during 2006 partially offset our repurchase of 1,088,500 treasury shares of common stock at a weighted average purchase price of $42.71. See below for additional discussion and analysis of cash flow.

	Year-Ended December 31,		
(In thousands)	**2006**	2005	2004
Cash Flows Provided by Operating Activities	**$ 357,104**	$ 364,560	$ 273,022
Cash Flows Used by Investing Activities	**(187,353)**	(412,150)	(255,357)
Cash Flows (Used in) / Provided by Financing Activities	**(138,523)**	48,190	(8,363)
Net Increase in Cash and Cash Equivalents	**$ 31,228**	$ 600	$ 9,302

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 related to the sale of our offshore and south Louisiana properties, partially offset by an increase in earnings and an increase in working capital changes. 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. While we believe 2007 commodity production may exceed 2006 levels, 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 2005 increased $91.5 million over 2004. This increase was primarily due to higher commodity prices. Key components impacting net operating cash flows were commodity prices, production volumes and operating costs. Average realized natural gas prices increased 30% over 2004, while crude oil realized prices increased 40% over the same period. Production volumes declined slightly, with a less than one percent reduction of equivalent production in 2005 compared to 2004. 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, our capital expenditures may be periodically adjusted during any given year. Cash flows used in investing activities decreased by $224.8 million from 2005 to 2006 and increased by $156.8 million from 2004 to 2005. 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 sale of our offshore and certain south Louisiana properties.

The increase from 2004 to 2005 was primarily due to an increase in drilling activity in the East region and the Rocky Mountains area of our West region in response to higher commodity prices. Our continued drilling activity in Canada also contributed to the increase. In addition, we spent $73.1 million in proved property acquisitions, primarily in the Gulf Coast.

Financing Activities. 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. Cash flows used in financing activities for 2004 were $8.4 million, resulting from proceeds from the exercise of stock options, offset by the purchase of treasury shares and dividend payments.

At December 31, 2006, we had $10 million of debt outstanding under our credit facility. 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.

In August 1998, we announced that our Board of Directors authorized the repurchase of two million shares of our common stock in the open market or in negotiated transactions. As a result of the 3-for-2 stock split effected in March 2005, this figure was adjusted to three million shares. In October 2006, we announced that our Board of Directors increased the number of shares of our common stock authorized for repurchase by an additional two million shares for a total of five million shares. During 2006, we repurchased 1,088,500 shares of our common stock at a weighted average price of $42.71. All purchases executed to date have been through open market transactions. There is no expiration date associated with the authorization to repurchase our securities. The maximum number of shares that may yet be purchased under the plan as of December 31, 2006 was 2,397,650. 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,	
(In millions)	**2006**	2005
Debt (1)	**$ 240.0**	$ 340.0
Stockholders' Equity	**945.2**	600.2
Total Capitalization	**$1,185.2**	$ 940.2
Debt to Capitalization	**20%**	36%
Cash and Cash Equivalents	**$ 41.9**	$ 10.6

(1) Includes $20.0 million of current portion of long-term debt at both December 31, 2006 and 2005. Includes $10 million and $90 million, respectively, of borrowings under our revolving credit facility at December 31, 2006 and 2005.

For the year ended December 31, 2006, we paid dividends of $7.8 million on our common stock. A regular dividend of $0.04 per share of common stock, or $0.027 per share for dividends prior to the 3-for-2 stock split as adjusted for the split, has been declared for each quarter since we became a public company in 1990.

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 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, 2006.

(In millions)	**2006**	2005	2004
Capital Expenditures			
Drilling and Facilities	**$ 406.9**	$ 249.3	$ 174.0
Leasehold Acquisitions	**42.6**	22.1	18.3
Pipeline and Gathering	**24.2**	17.9	13.5
Other	**7.7**	1.4	1.6
	481.4	290.7	207.4
Proved Property Acquisitions	**6.7**	73.1	4.0
Exploration Expense	**49.4**	61.8	48.1
Total	**$ 537.5**	$ 425.6	$ 259.5

We plan to drill approximately 440 gross wells in 2007 compared with 387 gross wells drilled in 2006. This 2007 drilling program includes approximately $434 million in total capital and exploration expenditures, down from $537.5 million in 2006. 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 2007, 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 three years, and downward reserve revisions. This change is currently estimated to be approximately 15% greater than 2006 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 is five years. All loans are collateralized by the interests transferred to the employees in the producing properties. The outstanding loan balances are approximately $0.3 million in the aggregate, and the fair value of these guarantees are immaterial to our financial statements.

A summary of our known contractual obligations as of December 31, 2006 are set forth in the following table:

		Payments Due by Year			
(In thousands)	**Total**	2007	2008 to 2009	2010 to 2011	2012 & Beyond
Long-Term Debt (1)	**$ 240,000**	$ 20,000	$ 50,000	$ 75,000	$ 95,000
Interest on Long-Term Debt (2)	**91,888**	17,596	30,878	24,914	18,500
Firm Gas Transportation Agreements (3)	**85,118**	9,864	15,356	7,140	52,758
Drilling Rig Commitments (3)	**120,261**	54,382	63,629	2,250	—
Operating Leases (3)	**14,076**	5,014	8,254	808	—
Total Contractual Cash Obligations	**$ 551,343**	**$106,856**	**$ 168,117**	**$ 110,112**	**$ 166,258**

(1) Including current portion. At December 31, 2006, we had $10 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 $230 million long-term debt outstanding at December 31, 2006. Interest payments on the $10 million of outstanding borrowings on our revolving credit facility were calculated by assuming that the December 31, 2006 outstanding balance of $10 million will be outstanding through the 2009 maturity date and by assuming a constant interest rate of 8.25%, which was the December 31, 2006 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, 2006 was $22.7 million, down from $43.0 million at December 31, 2005, primarily due to the sale of the offshore and certain south Louisiana properties during the end of the third quarter of 2006.

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 uncertain, and the reserve data included in this document are only estimates. The process relies on interpretations of available geologic, geophysic, engineering and production data. The extent, quality and reliability of this technical data can vary. The degree of uncertainty varies among the four regions in which we operate. The estimation of reserves for certain properties sold in 2006 as well as a small number of properties currently held in the Gulf Coast region requires more estimates than in Canada and the East and West regions and inherently has more uncertainty surrounding reserve estimation. The differences in the reserve estimation process are substantially due to the geological conditions in which the wells are drilled. 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. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the accuracy of various mandated economic assumptions; and
- the judgment of the persons preparing the estimate.

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 $0.05 to $0.06 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 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 2006, 2005 and 2004, 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 $2.1 million or decrease by approximately $2.0 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, three and seven years, respectively. Average property lives in Canada are estimated to be four 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% annualized for 2006, and the Citigroup Pension Liability Index, which was 5.9% at the end of 2006. We look to these benchmarks as well as considering durations of expected benefit payments. We have determined based on these assumptions that a discount rate of 5.75% at December 31, 2006 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, 2006, the assumed rate of increase was 8.0%. 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 by a minimum of two percent annually 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 2006, 2005 and 2004. 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 $0.3 million for the year ended December 31, 2006. 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 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 record 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 year ended December 31, 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 granted to retirement-eligible employees in 2006 was $0.6 million.

We issued stock appreciation rights to executive employees 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 $1.0 million, before the effect of taxes, for 2006. In addition, a new type of performance share was issued to non-executive employees. These awards measure our performance based on three internal metrics, rather than a peer group's stock performance which we use to measure our other performance share awards. These awards cliff vest at the end of the three year service period. Compensation cost related to these new internal-metric based performance share awards granted to employees was $1.4 million, before the effect of taxes, for 2006. In addition, we incurred a $0.6 million ($0.4 million, net of tax) cumulative effect charge in the first quarter of 2006, which is included 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 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.

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 "Business" 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 the Company's 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, 2006, 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, the Company 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, in previous years, 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 the Company not being able to realize the full benefit of a market improvement.

Recently Issued Accounting Pronouncements

In February 2006, the Financial Accounting Standards Board (FASB) issued SFAS No. 155, "Accounting for Certain Hybrid Financial Instruments-an amendment of FASB Statements No. 133 and 140." SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument's form. We do not believe that our financial position, results of operations or cash flows will be impacted by SFAS No. 155 as we do not currently hold any hybrid financial instruments.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109." FIN No. 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 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 No. 48 provides additional guidance on measuring the amount of the uncertain tax position. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. We are completing our evaluation of the impact of the adoption of FIN No. 48 and believe that the impact will not have a material effect on our financial position, results of operations or cash flows.

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 U.S. 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. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. We are currently evaluating what impact SFAS No. 157 may have on our financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)." SFAS No. 158 requires recognition of the funded status of a benefit plan in the balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be as of a company's balance sheet date. Additional disclosures in the notes to the financial statements are required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. For public companies, the effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. The effective date of the new measurement date provision is for fiscal years ending after December 15, 2008; however, our measurement date is currently our balance sheet date, so no change will be required. The incremental effect of SFAS No. 158, as discussed in Note 5 of the Notes to the Consolidated Financial Statements, was an increase to total long-term liabilities of $21.7 million, an increase to current liabilities of $0.6 million, an increase to total assets of $8.2 million and a decrease to total stockholders' equity of $14.1 million based on actuarial reports as of December 31, 2006.

In September 2006, the SEC Staff issued Staff Accounting Bulletin (SAB) No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. We have adopted the provisions of SAB No. 108 and there was no impact to our financial position, results of operations and cash flows as a result of this pronouncement.

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

2006 and 2005 Compared

We reported net income for the year ended December 31, 2006 of $321.2 million, or $6.64 per share. During 2005, we reported net income of $148.4 million, or $3.04 per share. Net income increased in the current period 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 disposition of our offshore and certain south Louisiana properties 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 divestiture of our offshore and certain south Louisiana properties. 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 sale of properties 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 Mbbl 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.

Other Operating Revenues

Other operating revenues increased by $6.2 million from 2005 to 2006. This change was primarily a result of an increase in revenues from net profits interest that originated in 2006 as well as a decrease in our payout liability associated with a favorable legal ruling in the first quarter of 2006, which correspondingly increased other revenues, and favorable settlements of state severance tax audits. This variance also results, to a lesser extent, from changes in our wellhead gas imbalances over the previous year period.

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.

2005 and 2004 Compared

We reported net income for the year ended December 31, 2005 of $148.4 million, or $3.04 per share. During 2004, we reported net income of $88.4 million, or $1.81 per share. Operating income increased by $98.0 million compared to the prior year, from $160.7 million to $258.7 million. The increase in operating income from 2004 to 2005 was principally due to an increase in natural gas and oil production revenues partially offset by an increase in total operating expenses. Net income increased from 2004 to 2005 by $60.0 million due to an increase in operating income partially offset by an increase of $37.6 million in income tax expense.

Natural Gas Production Revenues

Our average total company realized natural gas production sales price, including the realized impact of derivative instruments, was $6.74 per Mcf compared to $5.20 per Mcf for the comparable period of the prior year. These prices include the realized impact of derivative instruments, which reduced these prices by $1.33 per Mcf in 2005 and $0.76 per Mcf in 2004. The following table excludes the unrealized gain from the change in derivative fair value of $1.1 million and $0.9 million for the years ended December 31, 2005 and 2004, respectively. 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	
	2005	2004	Amount	Percent
Natural Gas Production *(Mmcf)*				
East	21,435	19,442	1,993	10%
Gulf Coast	28,071	31,358	(3,287)	(10%)
West	23,224	21,866	1,358	6%
Canada	1,149	167	982	588%
Total Company	73,879	72,833	1,046	1%
Natural Gas Production Sales Price *($/Mcf)*				
East	$ 8.02	$ 5.60	$ 2.42	43%
Gulf Coast	$ 6.38	$ 5.27	$ 1.11	21%
West	$ 6.00	$ 4.75	$ 1.25	26%
Canada	$ 6.79	$ 4.69	$ 2.10	45%
Total Company	$ 6.74	$ 5.20	$ 1.54	30%
Natural Gas Production Revenue *(In thousands)*				
East	$ 171,902	$ 108,935	$ 62,967	58%
Gulf Coast	179,061	165,177	13,884	8%
West	139,298	103,851	35,447	34%
Canada	7,802	784	7,018	895%
Total Company	$ 498,063	$ 378,747	$119,316	32%

Price Variance Impact on Natural Gas Production Revenue *(In thousands)*	
East	$ 51,798
Gulf Coast	31,200
West	28,997
Canada	2,414
Total Company	$ 114,409

Volume Variance Impact on Natural Gas Production Revenue *(In thousands)*	
East	$ 11,170
Gulf Coast	(17,317)
West	6,448
Canada	4,606
Total Company	$ 4,907

The increase in Natural Gas Production Revenue is due substantially to the increase in natural gas sales prices. In addition, the slight increase in production was due to the successful drilling programs in the East, West and Canada. Partially offsetting this was the decrease in the Gulf Coast production. The increase in the realized natural gas price combined with the increase in production resulted in a net revenue increase of $119.3 million.

Brokered Natural Gas Revenue and Cost

	Year Ended December 31,		Variance	
	2005	2004	Amount	Percent
Sales Price *($/Mcf)*	$ 9.14	$ 6.56	$ 2.58	39%
Volume Brokered *(Mmcf)*	10,793	12,876	(2,083)	(16%)
Brokered Natural Gas Revenues *(In thousands)*	$ 98,605	$ 84,416		
Purchase Price *($/Mcf)*	$ 8.08	$ 5.84	$ 2.24	38%
Volume Brokered *(Mmcf)*	10,793	12,876	(2,083)	(16%)
Brokered Natural Gas Cost *(In thousands)*	$ 87,183	$ 75,217		
Brokered Natural Gas Margin *(In thousands)*	$ 11,422	$ 9,199	$ 2,223	24%

(In thousands)	
Sales Price Variance Impact on Revenue	$ 27,852
Volume Variance Impact on Revenue	(13,664)
	$ 14,188

(In thousands)	
Purchase Price Variance Impact on Purchases	$ (24,130)
Volume Variance Impact on Purchases	12,165
	$ (11,965)

The increased brokered natural gas margin of $2.2 million was driven by an increased sales price that outpaced the increase in purchase cost, offset in part by a decrease in volume.

Crude Oil and Condensate Revenues

Our average total company realized crude oil sales price for 2005, including the realized impact of derivative instruments, was $44.19 per Bbl compared to $31.55 per Bbl for 2004. These prices include the realized impact of derivative instruments, which reduced these prices by $9.93 per Bbl in 2005 and $8.98 per Bbl in 2004. The following table excludes the unrealized gain from the change in derivative fair value of $5.5 million and the unrealized loss from the change in derivative fair value of $2.9 million for the years ended December 31, 2005 and 2004, respectively. 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	
	2005	2004	Amount	Percent
Crude Oil Production *(Mbbl)*				
East	27	27	—	—
Gulf Coast	1,528	1,805	(277)	(15%)
West	166	159	7	4%
Canada	18	4	14	350%
Total Company	1,739	1,995	(256)	(13%)
Crude Oil Sales Price *($/Bbl)*				
East	$ 53.84	$ 38.28	$ 15.56	41%
Gulf Coast	$ 42.81	$ 30.67	$ 12.14	40%
West	$ 55.37	$ 40.29	$ 15.08	37%
Canada	$ 43.39	$ 37.93	$ 5.46	14%
Total Company	$ 44.19	$ 31.55	$ 12.64	40%
Crude Oil Revenue *(In thousands)*				
East	$ 1,463	$ 1,049	$ 414	39%
Gulf Coast	65,427	55,357	10,070	18%
West	9,155	6,404	2,751	43%
Canada	791	129	662	513%
Total Company	$ 76,836	$ 62,939	$ 13,897	22%
Price Variance Impact on Crude Oil Revenue *(In thousands)*				
East	$ 423			
Gulf Coast	18,547			
West	2,496			
Canada	100			
Total Company	$ 21,566			
Volume Variance Impact on Crude Oil Revenue *(In thousands)*				
East	$ —			
Gulf Coast	(8,492)			
West	299			
Canada	524			
Total Company	$ (7,669)			

The increase in the realized crude oil price combined with the decline in production resulted in a net revenue increase of $13.9 million. The decrease in oil production is primarily the result of the decrease in the Gulf Coast region production due to the continued natural decline of the CL&F lease in south Louisiana, as well as the impact of hurricanes which included the shutting in and deferring of production at the Breton Sound offshore lease, one of our largest areas of offshore oil production.

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,			
	2005		2004	
(In thousands)	Realized	Unrealized	Realized	Unrealized
Operating Revenues - Increase/(Decrease) to Revenue				
Cash Flow Hedges				
Natural Gas Production	$ (98,223)	$ 1,114	$ (54,564)	$ 137
Crude Oil	(2,430)	(6)	—	6
Total Cash Flow Hedges	(100,653)	1,108	(54,564)	143
Other Derivative Financial Instruments				
Natural Gas Production	—	—	(444)	777
Crude Oil	(14,842)	5,518	(17,908)	(2,923)
Total Other Derivative Financial Instruments	(14,842)	5,518	(18,352)	(2,146)
	$ (115,495)	$ 6,626	$ (72,916)	$ (2,003)

We are exposed to market risk 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.

Other Operating Revenues

Other operating revenues decreased $3.6 million. This change was primarily a result of an increase in our payout liability associated with the reduction of our interest due to customary reversionary interest owned by others, which correspondingly decreased other operating revenues. In addition, our revenues from net profits interest declined over the prior year. This revenue variance also results, to a lesser extent, from changes in our wellhead gas imbalances over the previous year.

Operating Expenses

Total costs and expenses from operations increased $54.5 million for the year ended December 31, 2005 compared to the year ended December 31, 2004. The primary reasons for this fluctuation are as follows:

- Exploration expense increased $13.7 million in 2005, primarily as a result of increased dry hole expenses partially offset by decreased spending on geological and geophysical expenses. During 2005, we spent $6.8 million less on geological and geophysical activities but incurred an additional $18.9 million in dry hole expense. In addition, we spent an additional $0.8 million on delay rentals. The increase in dry hole expense is mainly due to expenses incurred in the Gulf Coast and, to a smaller extent, in Canada and the West.
- Taxes Other Than Income increased by $13.3 million from 2004 compared to 2005, primarily due to increased production taxes as a result of increased commodity prices. Additionally, ad valorem and franchise taxes were higher compared to the prior year.
- Brokered Natural Gas Cost increased by $12.0 million from 2004 to 2005. See the preceding table labeled "Brokered Natural Gas Revenue and Cost" for further analysis.
- Direct Operations expense increased by $8.2 million. This is primarily the result of increased expenses for outside operated properties and workovers. In addition, there were increases over the prior year in maintenance charges, equipment expenses and employee related expenses.
- Depreciation, Depletion and Amortization increased by $5.1 million in 2005. This is primarily due to an increase in offshore DD&A rates associated with the commencement of offshore production in late 2004 and increased production in the East and West regions.
- Impairment of Oil and Gas Properties decreased by $3.5 million as we incurred no impairment expense in the current year. The costs incurred in the prior year related to a field in south Louisiana. Further analysis of this impairment is discussed in Note 2 of the Notes to the Consolidated Financial Statements.
- Impairment of Unproved Properties increased $2.8 million over the prior year. This is due to increased amortization related to unproved property additions both offshore and onshore, including an increase in our Canadian additions.

- General and Administrative expense increased by $2.9 million in 2005. This increase is primarily due to increased stock compensation expense relating to performance share awards, increased professional services fees and higher employee related expenses. Partially offsetting these increases was a decrease in miscellaneous expenses, primarily due to the reversal of the reserve attributable to litigation that was settled in the 2005 period.

Interest Expense, Net

Interest expense, net increased $0.1 million. Interest expense related to borrowings under our revolving credit facility was higher in the current year due to higher average borrowings. Weighted average borrowings based on daily balances were approximately $32 million during 2005 compared to approximately $10 million during 2004. In addition, the effective interest rate on the credit facility increased to 6.9% during 2005 from 4.2% during the prior year. Partially offsetting this was an increase in interest income on our short-term investments.

Income Tax Expense

Income tax expense increased $37.6 million due to an increase in our pre-tax net income. The effective tax rates for 2005 and 2004 were 37.2% and 36.2%, 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, 2006, we had 20 cash flow hedges open: 19 natural gas price collar arrangements and one crude oil price collar arrangement. At December 31, 2006, an $82.0 million ($51.2 million, net of tax) unrealized gain was recorded to Accumulated Other Comprehensive Income, along with an $82.0 million short-term derivative receivable. 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.

Assuming no change in commodity prices, after December 31, 2006 we would expect to reclassify to the Consolidated Statement of Operations, over the next 12 months, $51.2 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, 2006 related to anticipated 2007 production.

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 2006, natural gas price collars covered 27,179 Mmcf of our gas production, or 34% of our gas production with a weighted average floor of $8.25 per Mcf and a weighted average ceiling of $12.74 per Mcf. During 2006, an oil price collar covered 365 Mbbl of our crude oil production, or 26% of our crude oil production with an average floor of $50.00 per Mbbl and an average ceiling of $76.00 per Mbbl.

At December 31, 2006, we had open natural gas price collar contracts covering our 2007 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, 2006			
First Quarter 2007	10,487	$12.19/$8.99	
Second Quarter 2007	10,604	12.19/8.99	
Third Quarter 2007	10,721	12.19/8.99	
Fourth Quarter 2007	10,721	12.19/8.99	
Full Year 2007	**42,533**	**$12.19/$8.99**	**$ 81,393**

At December 31, 2006, we had one open crude oil price collar contract covering our 2007 production as follows:

	Crude Oil Price Collar		
Contract Period	Volume in Mbbl	Average Ceiling / Floor *(per Bbl)*	Net Unrealized Gain *(In thousands)*
As of December 31, 2006			
First Quarter 2007	90	$80.00/$60.00	
Second Quarter 2007	91	80.00/60.00	
Third Quarter 2007	92	80.00/60.00	
Fourth Quarter 2007	92	80.00/60.00	
Full Year 2007	**365**	**$80.00/$60.00**	**$ 589**

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

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

Fair Market Value of Financial Instruments

The estimated fair value of financial instruments is the amount at which the instrument could be exchanged currently between willing parties. The carrying amounts reported in the consolidated balance sheet for cash and cash equivalents, accounts receivable, and accounts payable approximate fair value. The Company uses 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, 2006		December 31, 2005	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Long-Term Debt				
7.19% Notes	**$ 60,000**	**$ 61,749**	$ 80,000	$ 83,295
7.26% Notes	**75,000**	**80,335**	75,000	81,713
7.36% Notes	**75,000**	**82,025**	75,000	83,990
7.46% Notes	**20,000**	**22,547**	20,000	23,083
Credit Facility	**10,000**	**10,000**	90,000	90,000
Current Maturities				
7.19% Notes	**(20,000)**	**(20,299)**	(20,000)	(20,357)
Long-Term Debt, excluding Current Maturities	**$ 220,000**	**$ 236,357**	$ 320,000	$ 341,724

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:

We have completed integrated audits of Cabot Oil & Gas Corporation's consolidated financial statements and of its internal control over financial reporting as of December 31, 2006 in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of Cabot Oil & Gas Corporation and its subsidiaries at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Notes 1 and 5 to the consolidated financial statements, effective December 31, 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)."

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in *Internal Control – Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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 28, 2007

CONSOLIDATED STATEMENT OF OPERATIONS

	Year Ended December 31,		
(In thousands, except per share amounts)	**2006**	2005	2004
OPERATING REVENUES			
Natural Gas Production	**$ 568,097**	$ 499,177	$ 379,661
Brokered Natural Gas	**93,651**	98,605	84,416
Crude Oil and Condensate	**91,380**	82,348	60,022
Other	**8,860**	2,667	6,309
	761,988	682,797	530,408
OPERATING EXPENSES			
Brokered Natural Gas Cost	**83,375**	87,183	75,217
Direct Operations - Field and Pipeline	**74,790**	61,750	53,581
Exploration	**49,397**	61,840	48,130
Depreciation, Depletion and Amortization	**128,975**	108,458	103,343
Impairment of Unproved Properties	**11,117**	12,966	10,145
Impairment of Oil & Gas Properties (Note 2)	**3,886**	—	3,458
General and Administrative	**58,168**	37,650	34,735
Taxes Other Than Income	**55,351**	54,293	41,022
	465,059	424,140	369,631
Gain / (Loss) on Sale of Assets	**232,017**	74	(124)
INCOME FROM OPERATIONS	**528,946**	258,731	160,653
Interest Expense and Other	**18,441**	22,497	22,029
Income Before Income Taxes	**510,505**	236,234	138,624
Income Tax Expense	**189,330**	87,789	50,246
NET INCOME	**$ 321,175**	$ 148,445	$ 88,378
Basic Earnings Per Share	**$ 6.64**	$ 3.04	$ 1.81
Diluted Earnings Per Share	**$ 6.51**	$ 2.99	$ 1.79
Weighted Average Common Shares Outstanding	**48,402**	48,856	48,733
Diluted Common Shares (Note 13)	**49,300**	49,725	49,339

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

CONSOLIDATED BALANCE SHEET

(In thousands, except per share amounts)	December 31 2006	2005
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	**$ 41,854**	$ 10,626
Accounts Receivable, Net	**116,546**	156,009
Income Taxes Receivable	**24,512**	12,239
Inventories	**32,997**	24,616
Deferred Income Taxes	**9,386**	15,674
Derivative Contracts	**81,982**	1,736
Other	**8,405**	9,412
Total Current Assets	**315,682**	230,312
PROPERTIES AND EQUIPMENT, NET (Successful Efforts Method)	**1,480,201**	1,238,055
Deferred Income Taxes	**30,912**	19,587
OTHER ASSETS	**7,696**	7,416
	$ 1,834,491	$ 1,495,370
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts Payable	**$ 147,680**	$ 140,006
Current Portion of Long-Term Debt	**20,000**	20,000
Deferred Income Taxes	**31,962**	941
Derivative Contracts	**—**	22,478
Income Taxes Payable	**9,282**	41
Accrued Liabilities	**42,103**	35,118
Total Current Liabilities	**251,027**	218,584
LONG-TERM LIABILITY FOR PENSION BENEFITS (Note 5)	**7,219**	5,904
LONG-TERM LIABILITY FOR POSTRETIREMENT BENEFITS (Note 5)	**18,204**	6,517
LONG-TERM DEBT (Note 4)	**220,000**	320,000
DEFERRED INCOME TAXES	**347,430**	289,381
OTHER LIABILITIES	**45,413**	54,773
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS' EQUITY		
Common Stock:		
Authorized – 120,000,000 and 80,000,000 Shares of $.10 Par Value in 2006 and 2005, respectively		
Issued – 50,709,110 Shares and 50,081,983 Shares in 2006 and 2005, respectively	**5,071**	5,008
Additional Paid-in Capital	**423,066**	397,349
Retained Earnings	**565,591**	252,167
Accumulated Other Comprehensive Income / (Loss) (Note 14)	**37,160**	(15,115)
Less Treasury Stock, at Cost:		
2,602,350 and 1,513,850 Shares in 2006 and 2005, respectively	**(85,690)**	(39,198)
Total Stockholders' Equity	**945,198**	600,211
	$ 1,834,491	$ 1,495,370

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

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended December 31,		
(In thousands)	**2006**	2005	2004
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 321,175**	$ 148,445	$ 88,378
Adjustments to Reconcile Net Income to Cash			
Provided by Operating Activities:			
Depreciation, Depletion and Amortization	**128,975**	108,458	103,343
Impairment of Unproved Properties	**11,117**	12,966	10,145
Impairment of Oil & Gas Properties	**3,886**	—	3,458
Deferred Income Tax Expense	**52,011**	39,628	31,769
(Gain) / Loss on Sale of Assets	**(232,017)**	(74)	124
Exploration Expense	**49,397**	61,840	48,130
Unrealized (Gain) / Loss on Derivatives	**—**	(6,626)	2,003
Stock-Based Compensation Expense and Other	**21,271**	9,803	6,904
Changes in Assets and Liabilities:			
Accounts Receivable	**39,463**	(43,938)	(50,200)
Income Taxes Receivable	**(11,198)**	1,444	10,796
Inventories	**(8,381)**	(567)	(5,808)
Other Current Assets	**1,007**	1,188	3,255
Other Assets	**(733)**	(192)	(491)
Accounts Payable and Accrued Liabilities	**(29,694)**	26,147	17,254
Income Taxes Payable	**18,398**	3,656	(23)
Other Liabilities	**1,912**	2,382	3,985
Stock-Based Compensation Tax Benefit	**(9,485)**	—	—
Net Cash Provided by Operating Activities	**357,104**	364,560	273,022
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital Expenditures	**(467,430)**	(351,306)	(207,346)
Proceeds from Sale of Assets	**329,474**	996	119
Exploration Expense	**(49,397)**	(61,840)	(48,130)
Net Cash Used in Investing Activities	**(187,353)**	(412,150)	(255,357)
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase in Debt	**205,000**	265,000	187,000
Decrease in Debt	**(305,000)**	(195,000)	(187,000)
Sale of Common Stock Proceeds	**6,235**	4,586	12,474
Stock-Based Compensation Tax Benefit	**9,485**	—	—
Purchase of Treasury Stock	**(46,492)**	(19,183)	(15,631)
Dividends Paid	**(7,751)**	(7,213)	(5,206)
Net Cash (Used in) / Provided by Financing Activities	**(138,523)**	48,190	(8,363)
Net Increase in Cash and Cash Equivalents	**31,228**	600	9,302
Cash and Cash Equivalents, Beginning of Period	**10,626**	10,026	724
Cash and Cash Equivalents, End of Period	**$ 41,854**	$ 10,626	$ 10,026

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

CONSOLIDATED STATEMENT OF STOCKHOLDERS' EQUITY

(In thousands)	Common Shares	Stock Par	Treasury Shares	Treasury Stock	Paid-In Capital	Accumulated Other Comprehensive Income (Loss)[1]	Retained Earnings	Total
Balance at December 31, 2003	48,807	$ 4,881	454	$ (4,384)	$ 360,072	$ (23,135)	$ 27,763	$ 365,197
Net Income							88,378	88,378
Exercise of Stock Options	794	79			12,392			12,471
Purchase of Treasury Stock			608	(15,631)				(15,631)
Tax Benefit of Stock-Based Compensation					2,642			2,642
Stock Amortization and Vesting	80	8			5,019			5,027
Cash Dividends at $0.107 per Share							(5,206)	(5,206)
Other Comprehensive Income						2,784		2,784
Balance at December 31, 2004	49,681	$ 4,968	1,062	$ (20,015)	$ 380,125	$ (20,351)	$ 110,935	$ 455,662
Net Income							148,445	148,445
Exercise of Stock Options	300	30			4,555			4,585
Purchase of Treasury Stock			452	(19,183)				(19,183)
Tax Benefit of Stock-Based Compensation					3,662			3,662
Stock Amortization and Vesting	101	10			9,007			9,017
Cash Dividends at $0.147 per Share							(7,213)	(7,213)
Other Comprehensive Income						5,236		5,236
Balance at December 31, 2005	50,082	$ 5,008	1,514	$ (39,198)	$ 397,349	$ (15,115)	$ 252,167	$ 600,211
Net Income							321,175	**321,175**
Exercise of Stock Options	438	44			6,171			**6,215**
Purchase of Treasury Stock			1,088	(46,492)				**(46,492)**
Tax Benefit of Stock-Based Compensation					9,485			**9,485**
Stock Amortization and Vesting	189	19			10,061			**10,080**
Cash Dividends at $0.16 per Share							(7,751)	**(7,751)**
Effect of Adoption of SFAS No. 158						(14,079)		**(14,079)**
Other Comprehensive Income						66,354		**66,354**
Balance at December 31, 2006	**50,709**	**$ 5,071**	**2,602**	**$ (85,690)**	**$ 423,066**	**$ 37,160**	**$ 565,591**	**$ 945,198**

(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)	**2006**	2005	2004
Net Income	**$ 321,175**	$ 148,445	$ 88,378
Other Comprehensive Income, net of taxes			
Reclassification Adjustment for Settled Contracts, net of taxes of $10,686, ($38,404) and ($20,394), respectively	**(17,580)**	62,249	33,122
Changes in Fair Value of Hedge Positions, net of taxes of ($49,311), $35,293 and $18,486, respectively	**81,679**	(57,266)	(30,008)
Minimum Pension Liability, net of taxes of ($1,848), $77 and $535, respectively	**3,081**	(128)	(869)
Foreign Currency Translation Adjustment, net of taxes of $507, ($427) and ($123), respectively	**(826)**	381	539
Total Other Comprehensive Income	**66,354**	5,236	2,784
Comprehensive Income	**$ 387,529**	$ 153,681	$ 91,162

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 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 have been retroactively adjusted to give effect to the 3-for-2 split of the Company's common stock.

Recently Issued Accounting Pronouncements

In February 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 155, "Accounting for Certain Hybrid Financial Instruments-an amendment of FASB Statements No. 133 and 140." SFAS No. 155 amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," and also resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155 was issued to eliminate the exemption from applying SFAS No. 133 to interests in securitized financial assets so that similar instruments are accounted for in a similar fashion, regardless of the instrument's form. The Company does not believe that its financial position, results of operations or cash flows will be impacted by SFAS No. 155 as it does not currently hold any hybrid financial instruments.

In July 2006, the FASB issued FASB Interpretation (FIN) No. 48, "Accounting for Uncertainty in Income Taxes-an interpretation of FASB Statement No. 109." FIN No. 48 provides guidance for recognizing and measuring uncertain tax positions, as defined in SFAS No. 109, "Accounting for Income Taxes." FIN No. 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 No. 48 provides additional guidance on measuring the amount of the uncertain tax position. Guidance is also provided regarding derecognition, classification, interest and penalties, interim period accounting, transition and disclosure of these uncertain tax positions. FIN No. 48 is effective for fiscal years beginning after December 15, 2006. The Company is completing its evaluation of the impact of the adoption of FIN No. 48 and believes that the impact will not have a material effect on its financial position, results of operations or cash flows.

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 U.S. 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. No new fair value measurements are prescribed, and SFAS No. 157 is intended to codify the several definitions of fair value included in various accounting standards. However, the application of this Statement may change current practices for certain companies. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007. The Company is currently evaluating what impact SFAS No. 157 may have on its financial position, results of operations or cash flows.

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)." SFAS No. 158 requires recognition of the funded status of a benefit plan in the balance sheet and the recognition through other comprehensive income of gains, losses, prior service costs and credits, net of tax, arising during the period but not included as a component of periodic benefit cost. In addition, the measurement date of plan assets and obligations must be as of a company's balance sheet date. Additional disclosures in the notes to the financial statements are required and guidance is prescribed regarding the selection of discount rates to be used in measuring the benefit obligation. For public companies, the effective date of SFAS No. 158 is as of the end of the fiscal year ending after December 15, 2006. The effective date of the new measurement date provision is for fiscal years ending after December 15, 2008; however, the Company's measurement date is currently its balance sheet date, so no change will be required. The incremental effect of SFAS No. 158, as discussed in Note 5 of the Notes to the Consolidated Financial Statements, was an increase to total long-term liabilities of $21.7 million, an increase to current liabilities of $0.6 million, an increase to total assets of $8.2 million and a decrease to total stockholders' equity of $14.1 million based on actuarial reports as of December 31, 2006.

In September 2006, the SEC Staff issued Staff Accounting Bulletin (SAB) No. 108, "Considering the Effects of Prior Year Misstatements when Quantifying Misstatements in Current Year Financial Statements," in an effort to address diversity in the accounting practice of quantifying misstatements and the potential for improper amounts on the balance sheet. Prior to the issuance of SAB No. 108, the two methods used for quantifying the effects of financial statement errors were the "roll-over" and "iron curtain" methods. Under the "roll-over" method, the primary focus is the income statement, including the reversing effect of prior year misstatements. The criticism of this method is that misstatements can accumulate on the balance sheet. On the other hand, the "iron curtain" method focuses on the effect of correcting the ending balance sheet, with less importance on the reversing effects of prior year errors in the income statement. SAB No. 108 establishes a "dual approach" which requires the quantification of the effect of financial statement errors on each financial statement, as well as related disclosures. Public companies are required to record the cumulative effect of initially adopting the "dual approach" method in the first year ending after November 16, 2006 by recording any necessary corrections to asset and liability balances with an offsetting adjustment to the opening balance of retained earnings. The use of this cumulative effect transition method also requires detailed disclosures of the nature and amount of each error being corrected and how and when they arose. The Company has adopted the provisions of SAB No. 108 and there was no impact to its financial position, results of operations and cash flows as a result of this pronouncement.

Inventories

Inventories are comprised of natural gas and 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. A determination of whether a well has found proved reserves is made shortly after drilling is completed. The determination is based on a process which relies on interpretations of available geologic, geophysic, 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.

In the absence of a determination as to whether the reserves that have been found can be classified as proved, the costs of drilling such an exploratory well is not carried as an asset for more than one year following completion of drilling. If, after that year has passed, a determination that proved reserves exist cannot be made, the well is assumed to be impaired, and its costs are charged to expense. Its costs can, however, continue to be capitalized if a sufficient quantity of reserves are discovered in the well to justify its completion as a producing well and sufficient progress is made in assessing the reserves and the well's economic and operating feasibility.

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. The Company determines if an impairment has occurred through either adverse changes or as a result of the annual review of all fields. During 2006 and 2004, the Company recorded total impairments of $3.9 million and $3.5 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 amortized over 12 to 25 years, gathering and compression equipment is amortized over 10 years and storage equipment and facilities are amortized 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 certain assets during 2006.

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 $10.3 million, $11.4 million and $9.2 million of brokered natural gas margin in 2006, 2005 and 2004, 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.

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, 2006 and 2005 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 Balance Sheet, was $4.6 million and $5.6 million at December 31, 2006 and 2005, respectively.

Risk Management Activities

From time to time, the Company enters into derivative contracts, such as natural gas and crude oil price swaps or costless 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.

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, 2006 and 2005, 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.

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 and deferred income taxes. Actual results could differ from those estimates.

2. Properties and Equipment

Properties and equipment are comprised of the following:

	December 31,	
(In thousands)	**2006**	2005
Unproved Oil and Gas Properties	**$ 114,108**	$ 107,787
Proved Oil and Gas Properties	**2,109,045**	1,970,407
Gathering and Pipeline Systems	**205,473**	178,876
Land, Building and Improvements	**4,976**	4,892
Other	**34,067**	33,077
	2,467,669	2,295,039
Accumulated Depreciation, Depletion and Amortization	**(987,468)**	(1,056,984)
	$ 1,480,201	$ 1,238,055

On January 1, 2005, the Company adopted FASB Staff Position (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 2006, 2005 and 2004.

	December 31,		
(In thousands)	**2006**	2005	2004
Beginning balance at January 1	**$ 6,132**	$ 8,591	$ 3,681
Additions to capitalized exploratory well costs pending the determination of proved reserves	**8,317**	6,132	8,591
Reclassifications to wells, facilities, and equipment based on the determination of proved reserves	**(5,926)**	(1,069)	(3,395)
Capitalized exploratory well costs charged to expense	**(95)**	(7,522)	(286)
Ending balance at December 31	**$ 8,428**	$ 6,132	$ 8,591

At December 31, 2006, the Company had four projects that had exploratory well costs that were capitalized for a period greater than one year. At December 31, 2005 and 2004, the Company did not have any projects that have been 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)	**2006**	2005	2004
Capitalized exploratory well costs that have been capitalized for a period of one year or less	**$ 8,317**	$ 6,132	$ 8,591
Capitalized exploratory well costs that have been capitalized for a period greater than one year	**111**	—	—
Balance at December 31	**$ 8,428**	$ 6,132	$ 8,591
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 is being 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.

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 addition, there is another well that completed drilling in January 2007 and is awaiting completion results before confirmation of proved reserves can be made in the first quarter of 2007.

At December 31, 2005, the Company had no wells that had completed drilling where a determination of whether proved reserves existed could not be made.

At December 31, 2004, the Company had three wells that had completed drilling where a determination of whether proved reserves existed could not be made. One well was in the Rocky Mountains area and reached total depth in November 2004. It could not be completed due to the Bureau of Land Management stipulation which prohibited activity until the summer of 2005. Two wells in Canada completed drilling in October and December 2004. These wells were awaiting completion or sidetracking which was anticipated to commence by May 2005. Additional operations were performed on each of these wells, and all were determined to be unsuccessful. In 2005, $8.0 million was charged to expense for these wells, which was made up of $3.1 million for the Rocky Mountains area well and $4.9 million for the two wells in Canada.

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. During 2005, the Company did not record any impairments. During 2004, the Company recorded an impairment of $3.5 million. The impairment was recorded on a two-well field in south Louisiana and was due to production performance issues related to water encroachment. These 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.

Disposition of Assets

On September 29, 2006, the Company substantially completed the sale of its offshore portfolio and certain south Louisiana properties to Phoenix Exploration Company LP (Phoenix) for a gross sales price of $340.0 million. The properties sold included proved reserves of approximately 98 Bcfe, as of the August 1, 2006 effective date, including 68 Bcfe of proved reserves recorded as of December 31, 2005 and had average daily production for the first nine months of 2006 of 47.4 Mmcfe.

Pursuant to the asset purchase agreement for the sale, dated August 25, 2006, the gross sales price was offset by the net cash flow from operation of the properties from August 1, 2006 through the closing date and other purchase price adjustments. The net proceeds from the sale were used to add funding to the Company's capital program, repurchase shares of common stock, repay outstanding debt under the revolving credit facility and pay taxes related to the transaction. Also pursuant to the agreement, the Company entered into certain commodity price swaps on behalf of Phoenix. At closing on September 29, 2006, these derivative instruments were assigned to Phoenix, and the Company was released from all rights and obligations with respect thereto. There was no ultimate impact on the Company's financial statements due to the existence of these swaps.

Through December 31, 2006, the Company had received approximately $327.5 million in net proceeds from the sale, which reflects the $340.0 million gross sales price, reduced by purchase price adjustments of $4.0 million as well as amounts attributable to consents and preferential rights expected to be settled in the first quarter of 2007 of $8.5 million. A net gain of $231.2 million ($144.5 million, net of tax) was recorded in the Consolidated Statement of Operations for the year ended December 31, 2006, calculated as follows:

(In millions)	
Cash Proceeds	$ 327.5
Less:	
Remaining purchase price adjustments	11.1
Carrying value of properties sold	104.2
Asset retirement obligation of properties sold	(23.9)
Deferred gain	4.4
Transaction costs	0.5
Pre-tax gain	**$ 231.2**

The net impact of the purchase price adjustments will be reflected in cash flows from investing activities when such settlements are made. In addition, a gain of approximately $12 million is expected to be recognized in the first quarter of 2007 in connection with the closing of certain property sales to Phoenix for which third party consents (including deferred amounts) had not been obtained as of December 31, 2006 and sales to other parties that exercised their contractual preferential rights. This gain will be subject to customary purchase price adjustments.

3. Additional Balance Sheet Information

Certain balance sheet amounts are comprised of the following:

	December 31,	
(In thousands)	**2006**	2005
ACCOUNTS RECEIVABLE		
Trade Accounts	**$ 102,023**	$ 147,016
Joint Interest Accounts	**18,574**	14,319
Other Accounts	**501**	315
	121,098	161,650
Allowance for Doubtful Accounts	**(4,552)**	(5,641)
	$ 116,546	$ 156,009
INVENTORIES		
Natural Gas and Oil in Storage	**$ 22,717**	$ 18,279
Tubular Goods and Well Equipment	**7,680**	7,161
Pipeline Imbalances	**2,600**	(824)
	$ 32,997	$ 24,616
OTHER CURRENT ASSETS		
Drilling Advances	**$ 651**	$ 2,169
Prepaid Balances	**7,416**	6,939
Other Accounts	**338**	304
	$ 8,405	$ 9,412
ACCOUNTS PAYABLE		
Trade Accounts	**$ 28,569**	$ 18,227
Natural Gas Purchases	**8,356**	12,208
Royalty and Other Owners	**37,230**	49,312
Capital Costs	**59,524**	37,489
Taxes Other Than Income	**4,805**	10,329
Drilling Advances	**1,506**	5,760
Wellhead Gas Imbalances	**2,288**	2,175
Other Accounts	**5,402**	4,506
	$ 147,680	$ 140,006
ACCRUED LIABILITIES		
Employee Benefits	**$ 13,575**	$ 7,316
Current Liability for Pension Benefits	**67**	1,204
Current Liability for Postretirement Benefits	**577**	500
Taxes Other Than Income	**15,696**	16,188
Interest Payable	**5,995**	6,818
Other Accounts	**6,193**	3,092
	$ 42,103	$ 35,118
OTHER LIABILITIES		
Rabbi Trust Deferred Compensation Plan	**$ 6,077**	$ 4,883
Accrued Plugging and Abandonment Liability	**22,655**	42,991
Other Accounts	**16,681**	6,899
	$ 45,413	$ 54,773

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 starting in November 2005. The Company made the required $20 million payments in both 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 $10 million and $90 million were outstanding at December 31, 2006 and 2005, 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 effective interest rates for the credit facility during the years ended December 31, 2006, 2005 and 2004 were 7.9%, 6.9% and 4.2%, respectively. As of December 31, 2006, the weighted average interest rate on the Company's credit facility was 8.25%. 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 was in compliance in all material respects with its covenants contained in its various debt agreements at December 31, 2006 and 2005 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 fixed income investments and equity securities. 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)	**2006**	2005	2004
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 41,211**	$ 36,066	$ 33,547
Service Cost	**2,720**	1,803	2,014
Interest Cost	**2,333**	1,981	2,078
Actuarial Loss	**5**	1,852	1,798
Plan Amendments	**(3)**	120	—
Benefits Paid	**(791)**	(611)	(3,371)
Benefit Obligation at End of Year	**45,475**	41,211	36,066
Change in Plan Assets			
Fair Value of Plan Assets at Beginning of Year	**23,765**	18,092	18,683
Actual Return on Plan Assets	**3,587**	1,544	957
Employer Contributions	**12,008**	5,000	2,000
Benefits Paid	**(791)**	(611)	(3,371)
Expenses Paid	**(380)**	(260)	(177)
Fair Value of Plan Assets at End of Year	**38,189**	23,765	18,092
Funded Status at End of Year	**$ (7,286)**	$ (17,446)	$ (17,974)

Amounts Recognized in the Balance Sheet

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

(In thousands)	**2006**	2005	2004
Long-Term Assets	**$ —**	$ 454	$ 570
Current Liabilities	**(67)**	(1,204)	(3,579)
Long-Term Liabilities	**(7,219)**	(5,904)	(5,089)
	$ (7,286)	$ (6,654)	$ (8,098)

Amounts Recognized in Accumulated Other Comprehensive Income

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

(In thousands)	2006	2005	2004
Prior Service Cost	$ 336	$ —	$ —
Net Actuarial Loss	12,946	—	—
Minimum Pension Liability	—	(5,119)	(4,914)
	$ 13,282	$ (5,119)	$ (4,914)

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 $0.7 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 approximately $0.1 million each.

The combined accumulated benefit obligation for both pension plans was $34.8 million, $30.9 million and $26.8 million at December 31, 2006, 2005 and 2004, respectively.

Components of Net Periodic Benefit Cost

Qualified Pension Plan

(In thousands)	2006	2005	2004
Qualified Components of Net Periodic Benefit Cost			
Current Year Service Cost	$ 2,518	$ 2,485	$ 1,619
Interest Cost	2,211	1,896	1,697
Expected Return on Plan Assets	(1,962)	(1,507)	(1,474)
Amortization of Prior Service Cost	98	99	88
Amortization of Net Loss	1,125	921	383
Net Periodic Pension Cost	$ 3,990	$ 3,894	$ 2,313

Non-Qualified Pension Plan

(In thousands)	2006	2005	2004
Non-Qualified Components of Net Periodic Benefit Cost			
Current Year Service Cost	$ 203	$ (682)	$ 395
Interest Cost	122	85	381
Amortization of Prior Service Cost	77	77	77
Amortization of Net Loss / (Gain)	85	(22)	428
Net Periodic Pension Cost / (Income)	$ 487	$ (542)	$ 1,281

Assumptions

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

	2006	2005	2004
Discount Rate	**5.75%**	5.50%	5.75%
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:

	2006	2005	2004
Discount Rate	**5.50%**	5.75%	6.25%
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 2006, 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 by a minimum of two percent annually 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 2006, 2005 and 2004. 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, 2006 and 2005, the non-qualified pension plan did not have plan assets. The plan assets of the Company's qualified pension plan at December 31, 2006 and 2005, by asset category are as follows:

	2006		2005	
(In thousands)	Amount	Percent	Amount	Percent
Equity securities	**$ 27,124**	**71%**	$ 19,556	82%
Debt securities	**10,605**	**28%**	840	4%
Other (1)	**460**	**1%**	3,369	14%
Total	**$ 38,189**	**100%**	$ 23,765	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 2006, the Company did not have any required minimum funding obligations; however, it chose to fund $12 million into the qualified plan. In 2007, the Company does not have any required minimum funding obligations for the qualified pension plan. The Company will fund less than $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 2007.

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
2007	$ 960	$ 73	$ 1,033
2008	1,030	102	1,132
2009	1,306	128	1,434
2010	1,345	237	1,582
2011	1,537	167	1,704
Years 2012 - 2016	13,451	1,991	15,442

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 244 retirees and their dependants at the end of 2006 and 245 retirees and their dependants at the end of 2005.

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. As the postretirement plan does not have any plan assets, 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)	**2006**	2005	2004
Change in Benefit Obligation			
Benefit Obligation at Beginning of Year	**$ 11,793**	$ 14,101	$ 6,181
Service Cost	**789**	675	671
Interest Cost	**877**	605	784
Actuarial Loss / (Gain)	**6,337**	(876)	864
Plan Amendments	**(153)**	(1,434)	6,901
Benefits Paid	**(862)**	(1,278)	(1,300)
Benefit Obligation at End of Year	**18,781**	11,793	14,101
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	**$ (18,781)**	$ (11,793)	$ (14,101)

Amounts Recognized in the Balance Sheet

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

(In thousands)	2006	2005	2004
Current Liabilities	**$ (577)**	$ (500)	$ (500)
Long-Term Liabilities	**(18,204)**	(6,514)	(4,093)
	$ (18,781)	$ (7,014)	$ (4,593)

Amounts Recognized in Accumulated Other Comprehensive Income

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

(In thousands)	2006	2005	2004
Transition Obligation	**$ 3,159**	N/A	N/A
Prior Service Cost	**2,570**	N/A	N/A
Net Actuarial Loss	**3,705**	N/A	N/A
	$ 9,434	N/A	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)	2006	2005	2004
Components of Net Periodic Postretirement Benefit Cost			
Current Year Service Cost	**$ 789**	$ 675	$ 671
Interest Cost	**877**	605	784
Amortization of Prior Service Cost	**952**	910	1,211
Amortization of Net Obligation at Transition	**632**	648	662
Amortization of Net Loss / (Gain)	**32**	(79)	(59)
SFAS 106 Net Periodic Postretirement Cost	**3,282**	2,759	3,269
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	**$ 3,196**	$ 3,078	$ 3,269

Assumptions

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

	2006	2005	2004
Discount Rate [1]	5.75%	5.50%	5.75%
Health Care Cost Trend Rate for Medical Benefits Assumed for Next Year	8.00%	9.00%	10.00%
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	2010	2010	2009

(1) Represents the year end rates used to determine the projected benefit obligation. To compute postretirement cost in 2006, 2005 and 2004, respectively, the beginning of year discount rates of 5.5%, 5.75% and 6.25% 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	$ 385	$ (306)
Effect on postretirement benefit obligation	3,189	(2,582)

Cash Flows

Contributions

The Company expects to contribute approximately $0.6 million to the postretirement benefit plan in 2007.

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)	
2007	$ 594
2008	626
2009	662
2010	700
2011	753
Years 2012 - 2016	5,361

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 $1.8 million, $1.6 million and $1.4 million in 2006, 2005, and 2004, 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. At December 31, 2006, the balance in the Deferred Compensation Plan's rabbi trust was $6.1 million.

The employee participants guide the diversification of trust assets. The trust assets are invested in mutual funds that cover the investment spectrum from equity to money market. These mutual funds are publicly quoted and reported at market value. No shares of the Company's stock are held by the trust. Settlement payments are made to participants in cash, either in a lump sum or in periodic installments. The market value of the trust assets is recorded on the Company's balance sheet as a component of Other Assets and the corresponding liability is recorded as a component of Other Liabilities.

There is no impact on earnings or earnings per share from the changes in market value of the deferred compensation plan assets for two reasons. First, 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. Second, no shares of the Company's stock are held in the trust.

The Company charged to expense plan contributions of less than $20,000 in each of 2006, 2005 and 2004.

6. Income Taxes

Income tax expense (benefit) is summarized as follows:

	Year Ended December 31,		
(In thousands)	**2006**	2005	2004
Current			
Federal	**$ 123,155**	$ 42,976	$ 14,767
State	**14,164**	5,185	3,710
Total	**137,319**	48,161	18,477
Deferred			
Federal	**49,911**	37,565	31,779
State	**2,100**	2,063	(10)
Total	**52,011**	39,628	31,769
Total Income Tax Expense	**$ 189,330**	$ 87,789	$ 50,246

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

	Year Ended December 31,		
(In thousands)	**2006**	2005	2004
Statutory Federal Income Tax Rate	**35%**	35%	35%
Computed "Expected" Federal Income Tax	**$ 178,818**	$ 82,682	$ 48,518
State Income Tax, Net of Federal Income Tax Benefit	**14,494**	7,030	4,353
Other, Net	**(3,982)** (1)	(1,923) (2)	(2,625) (3)
Total Income Tax Expense	**$ 189,330**	$ 87,789	$ 50,246

(1) Other, Net includes credit adjustments of $2.3 million related to the qualified production activities deduction, $0.6 million related to the recognition of benefit for federal statutory depletion in excess of basis, $0.8 million related to the recognition of benefit for state statutory depletion in excess of basis, $2.6 million related to the reduction of the state statutory rate, and other permanent items. Other, Net also includes debit adjustments of $1.2 million related to excess compensation, $1.0 million related to performance shares, and other permanent items.

(2) Other, Net includes credit adjustments of $1.3 million related to the qualified production activities deduction, $0.6 million related to the recognition of benefit for federal statutory depletion in excess of basis, $1.0 million related to the recognition of benefit for state statutory depletion in excess of basis, $0.6 million related to the reduction of the state statutory rate and other permanent items. Other, Net also includes debit adjustments of $0.7 million related to excess compensation, $0.7 million related to Internal Revenue Service audit adjustments and other permanent items.

(3) Other, Net includes credit adjustments of $1.6 million related to the recognition of benefit for federal statutory depletion in excess of basis, $0.9 million related to the recognition of benefit for state statutory depletion in excess of basis, and other permanent items.

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:

	Year Ended December 31,	
(In thousands)	**2006**	2005
Deferred Tax Liabilities		
Property, Plant and Equipment	**$ 346,198**	$ 288,602
Items Accrued for Financial Reporting Purposes	**33,194**	1,720
Total	**379,392**	290,322
Deferred Tax Assets		
Net Operating Loss Carryforwards	**1,281**	2,591
Items Accrued for Financial Reporting Purposes	**30,564**	22,840
Other Comprehensive Income	**8,453**	9,830
Total	**40,298**	35,261
Net Deferred Tax Liabilities	**$ 339,094**	$ 255,061

As of December 31, 2006, the Company had a net operating loss carryforward of $25.5 million for state income tax reporting purposes, the majority of which will expire between 2020 and 2026 and none available for regular federal income tax purposes. It is expected that these deferred tax benefits will be utilized prior to their expiration.

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 region and the East region. The remaining terms on these agreements range from less than one year to 21 years and require the Company to pay transportation demand charges regardless of the amount of pipeline capacity utilized by the Company.

Future obligations under firm gas transportation agreements in effect at December 31, 2006 are as follows:

(In thousands)	
2007	$ 9,864
2008	8,248
2009	7,108
2010	3,716
2011	3,424
Thereafter	52,758
	$ 85,118

Drilling Rig Commitments

The Company has seven drilling rigs in the Gulf Coast that are under contract. Three existing drilling rigs are under contract with rig providers in the Gulf Coast. An additional four drilling rigs were built for rig providers for use by the Company, three of which were delivered in the fourth quarter of 2006. The fourth rig is expected to be delivered by April 2007. As of December 31, 2006, the Company is obligated over the next four years to pay $120.3 million as follows:

(In thousands)	
2007	$ 54,382
2008	41,127
2009	22,502
2010	2,250
	$ 120,261

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 three 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 $10.7 million, $9.1 million and $8.7 million for the years ended December 31, 2006, 2005, and 2004, respectively.

Future minimum rental commitments under non-cancelable leases in effect at December 31, 2006 are as follows:

(In thousands)	
2007	$ 5,014
2008	4,785
2009	3,469
2010	710
2011	98
Thereafter	—
	$ 14,076

Guarantees

On June 28, 2006, the Company announced the commencement of an offering under its Mineral, Royalty and Overriding Royalty Interest Plan. The Company assisted certain non-executive employees in obtaining loans to purchase interests offered under the 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 is five years. The outstanding loan balances are approximately $0.3 million in the aggregate, and the fair value of these guarantees are immaterial to the Company's financial statements. All loans are 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 have requested class certification and allege 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.

Discovery and pleadings necessary to place the class certification issue before the state court have been ongoing. The Court entered an order on June 1, 2005 granting the motion for class certification. The parties have negotiated a modification to the order which will result in the dismissal of the claims related to the gas sales contract settlement in connection with the Columbia Gas Transmission bankruptcy proceedings and that will limit the claims to those arising on and after December 17, 1991. The Court postponed the trial date from April 17, 2006, in light of the case involving an unrelated party pending before the West Virginia Supreme Court of Appeals described below. The Company intends to challenge the class certification order by filing a Petition for Writ of Prohibition with the West Virginia Supreme Court of Appeals.

The West Virginia Supreme Court of Appeals issued a decision in 2006 in a case against another producer (the Tawney case) that raised some of the same issues as are raised in the Company's case. This recent decision may negatively impact some of the defenses the Company has raised in its litigation with respect to the issue of deductibility of post-production expenses under certain leases, but it believes that in a significant number of leases the Company has lease language, factual distinctions and defenses that are not implicated by the ruling.

The Tawney case involves claims concerning the deductibility of post-production expenses and the failure to properly inform, issues shared with the Company's case, but also involves additional claims not raised in its case. The most significant additional claims are related to sales under long-term, fixed-price agreements at prices considered significantly below market value, as well as claims for certain volume reductions and unmetered production. The Tawney case went to trial in January 2007, and the jury returned a verdict against the producer for $130 million in compensatory damages and $270 million in punitive damages. Judgment has not yet been entered in the Tawney case, and an appeal is expected. The Company is closely monitoring developments in the Tawney case, and it continues to investigate how this recent ruling may impact its defense of the case. The case against the Company has been re-activated to the docket and trial is set for August 13, 2007.

The Company is vigorously defending the case. A reserve has been established that management believes is adequate based on its estimate of the probable outcome of this case.

Texas Title Litigation. On January 6, 2003, the Company was served with Plaintiffs' Second Amended Original Petition in Romeo Longoria, et al. v. Exxon Mobil Corporation, et al. in the 79th Judicial District Court of Brooks County, Texas. Plaintiffs filed their Second Supplemental Original Petition on November 12, 2004 and their Third Supplemental Original Petition on February 22, 2005 (which added Wynn-Crosby 1996, Ltd. and Dominion Oklahoma Texas Exploration & Production, Inc.). Plaintiffs filed their Third Amended Original Petition on February 21, 2006, which incorporated all prior supplemental petitions. Plaintiffs allege that they are the owners of a one-half undivided mineral interest in and to certain lands in Brooks County, Texas. Cody Energy, LLC, a subsidiary of the Company, acquired certain leases and wells in 1997 and 1998.

The plaintiffs allege that they are entitled to be declared the rightful owners of an undivided interest in minerals and all improvements on the lands on which the Company acquired these leases. The plaintiffs also assert claims for trespass to try title, action to remove a cloud on the title, failure to properly account for royalty, fraud, trespass and conversion, all for unspecified actual and exemplary damages. Plaintiffs claim that they acquired title to the property by adverse possession. Plaintiffs also assert the discovery rule and a claim of fraudulent concealment to avoid the affirmative defense of limitations. In August 2005, the case was abated until late February 2006, during which time the parties were allowed to amend pleadings or add additional parties to the litigation. Plaintiffs did not join additional parties by the abatement deadline. Defendants, including the Company, re-urged its motion to dismiss, and on April 5, 2006, the Court granted the motion, dismissing the oil company defendants, without prejudice. Because all defendants were not dismissed at that time, the order dismissing the Company was not then final. A motion to finalize the proceedings in the trial court via severance of the dismissed defendants was filed April 25, 2006, and the remaining defendants moved to join the motions that led to the dismissal of the Company. In 2006, the Court dismissed the claims.

Plaintiffs have filed a Notice of Appeal. Although the record is not yet complete and, therefore, specific appellate deadlines have not been set, the Company expects that, following briefing and oral argument, the appellate court will issue its decision by the end of 2007 or early 2008.

Raymondville Area. In April 2004, the Company's wholly owned subsidiary, Cody Energy, LLC, filed suit in state court in Willacy County, Texas against certain of its co-working interest owners in the Raymondville Area, located in Kenedy and Willacy Counties. In early 2003, Cody had proposed a new prospect under the terms of the Joint Operating Agreement. Some of the co-working interest owners elected not to participate. The initial well was successful and subsequent wells have been drilled to exploit the discovery made in the first well.

The working interest owners who elected not to participate notified Cody that they believed that they had the right to participate in wells drilled after the initial well. Cody contends that the working interest owners that elected not to participate are required to assign their interest in the prospect to those who elected to participate. The defendants filed a counter claim against Cody, and one of the defendants filed a lien against Cody's interest in the leases in the Raymondville Area.

Cody has signed a settlement agreement with certain of the defendants representing approximately three percent of the interest in the area. Cody and the remaining defendant filed cross motions for summary judgment. In August 2005, the trial judge entered an order granting Cody's Motion for Summary Judgment requiring the remaining defendant to assign to Cody all of its interest in the prospect and to remove the lien filed against Cody's interest.

On July 12, 2006, Cody entered into a Purchase and Sale Agreement to acquire all of the defendant's interest in the Raymondville Field. The agreement would make the summary judgment ruling by the trial judge a final order, dismiss, with prejudice, all pending counter claims filed by such defendant and remove the lien against Cody's properties filed by such defendant. Cody completed the acquisition in the third quarter of 2006. The lien has been removed, the summary judgment has become a final order and all of the defendant's claims have been dismissed.

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 $9.1 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 for interest and income taxes is as follows:

	Year Ended December 31,		
(In thousands)	**2006**	2005	2004
Interest	**$ 24,088**	$ 17,366	$ 16,415
Income Taxes	**128,752**	47,142	29,861

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, $3.7 million and $2.6 million for the years ended December 31, 2006, 2005 and 2004, respectively, for tax deductions taken due to employee stock option exercises and restricted stock grant vesting.

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 addition to the automatic award of an option to purchase 15,000 shares of common stock on the date the non-employee directors first join the board of directors. A total of 2,550,000 shares of common stock may be issued under the 2004 Incentive Plan. In addition, shares remaining available for award under the 1994 Long-Term Incentive Plan and the Second Amended and Restated 1994 Non-Employee Director Stock Option Plan (herein "Prior Plans") were subsumed into the 2004 Incentive Plan (342,597 shares post-split). Under the 2004 Incentive Plan, no more than 900,000 shares may be used for stock awards that are not subject to the achievement of performance based goals, and no more than 1,500,000 shares may be issued pursuant to incentive stock options. Awards outstanding under the Prior Plans will remain outstanding in accordance with their original terms and conditions.

Stock Split

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 have been retroactively adjusted to give effect to the 3-for-2 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

In August 1998, the Company announced that its Board of Directors authorized the repurchase of two million shares of the Company's common stock in the open market or in negotiated transactions. As a result of the 3-for-2 stock split of the Company's common stock in March 2005, this figure was adjusted to three million shares. On October 26, 2006, the Company announced that its Board of Directors increased the number of shares of the Company's common stock authorized for repurchase by an additional two million shares. 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, 2006, the Company repurchased 1,088,500 shares with a weighted average price per share of $42.71 for a total cost of approximately $46.5 million. All of the repurchases occurred during the second and third quarters. The repurchased shares are held as treasury stock. Since the authorization date, the Company has repurchased 2,602,350 shares, or 52% of the five million total shares authorized for repurchase at December 31, 2006, for a total cost of approximately $85.7 million. 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.

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, 2006 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 the 3-for-2 stock split, 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 two-thirds of one one-hundredth of a share of preferred stock at a purchase price of approximately $36.67 per two-thirds of one one-hundredth of a share. The redemption price of each right is now two-thirds 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, 2006, 2005 and 2004 was $21.2 million, $9.6 million and $6.5 million, respectively, and is included in General and Administrative Expense in the Consolidated Statement of Operations. The primary reason for this increase was due to an increase in the liability component of the performance share awards as well as expense related to performance shares granted in 2006. In 2006, compensation expense included amortization of restricted stock grants, stock options, SARs, restricted stock units and performance shares at fair value. 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, $3.7 million and $2.6 million for the years ended December 31, 2006, 2005 and 2004, respectively, for tax deductions taken due to employee stock option exercises and restricted stock grant vesting.

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 years ended December 31, 2005 and 2004:

	Year Ended December 31,	
(In thousands, except per share amounts)	2005	2004
Net Income, as reported	$ 148,445	$ 88,378
Add: Employee stock-based compensation expense, net of related tax effects, included in net income, as reported	5,965	4,043
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)	(5,614)
Pro forma net income	$ 147,478	$ 86,807
Earnings per Share:		
Basic - as reported	$ 3.04	$ 1.81
Basic - pro forma	$ 3.02	$ 1.78
Diluted - as reported	$ 2.99	$ 1.79
Diluted - pro forma	$ 2.97	$ 1.76
Share Count	48,856	48,733
Diluted Share Count	49,725	49,339

In September 2006, the SEC Staff issued a letter summarizing their 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 for awards that vest 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 a 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 terminations 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 the Company's ten year 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, 2006:

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, 2005	588,465	$ 26.68		
Granted	46,850	47.60		
Vested	(231,493)	21.76		
Forfeited	(5,000)	31.26		
Non-vested shares outstanding at December 31, 2006	**398,822**	**$ 31.93**	**1.4**	**$ 24,189**

(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, 2006 by the number of non-vested restricted stock awards outstanding.

As shown in the table above, there were 46,850 restricted stock awards granted to employees during 2006. All of these awards were granted in the first quarter of 2006. These awards granted in 2006 vest over a three year service period on a graded-vesting schedule. During the year ended December 31, 2005, 327,623 restricted stock awards were granted with a weighted-average grant date fair value per share of $31.88. During the year ended December 31, 2004, 215,250 restricted stock awards were granted with a weighted-average grant date fair value per share of $23.75. The total fair value of shares vested during 2006, 2005 and 2004 was $5.0 million, $2.2 million and $2.0 million, respectively.

Compensation expense recorded for restricted stock awards for the years ended December 31, 2006, 2005 and 2004 was $6.1 million, $5.6 million and $3.1 million, respectively. Included in the 2006 expense was $0.6 million related to the expensing of the entire value of shares granted to retirement-eligible employees. Unamortized expense as of December 31, 2006 for all outstanding restricted stock awards was $4.3 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, 2006:

Restricted Stock Units	Shares	Weighted-Average Grant Date Fair Value per share	Aggregate Intrinsic Value *(In thousands)*[(1)]
Outstanding at December 31, 2005	30,100	$ 31.30	
Granted and fully vested	17,220	50.82	
Issued	(8,600)	31.30	
Forfeited	—	—	
Outstanding at December 31, 2006	**38,720**	**$ 39.98**	**$ 2,348**

(1) The intrinsic value of restricted stock units is calculated by multiplying the closing market price of the Company's stock on December 31, 2006 by the number of outstanding restricted stock units as of December 31, 2006.

As shown in the table above, 17,220 restricted stock units were granted during 2006. During 2005, 19,600 restricted stock units were granted with a weighted-average grant date fair value per share of $35.58. During 2004, 10,500 restricted stock units were granted with a weighted-average grant date fair value per share of $23.32.

The compensation cost, which reflects the total fair value of these units, recorded entirely in the second quarter of 2006 was $0.9 million. Compensation expense recorded during the years ended December 31, 2005 and 2004 for restricted stock units was $0.7 million and $0.2 million, respectively.

Stock Options

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 on the date of grant) of the Company's stock at the date of grant. During the year ended December 31, 2006, 30,000 stock options, with an exercise price of $47.60 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. During 2004, 36,750 stock options were granted with an exercise price of $23.32 per share.

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 2006 for these stock options was $0.3 million. 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 2004 and no compensation expense was recorded. Unamortized expense as of December 31, 2006 for all outstanding stock options was $0.2 million. The weighted average period over which this compensation will be recognized is approximately 2.2 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,		
	2006	2005	2004
Weighted-Average Value per Option Granted During the Period (1)	**$ 14.65**	$ —	$ 7.54
Assumptions			
Stock Price Volatility	**31.5%**	—	38.4%
Risk Free Rate of Return	**4.6%**	—	3.3%
Expected Dividend	**0.3%**	—	0.8%
Expected Term (*In years*)	**4.0**	—	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 thorough 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 $0.04 per share dividend each quarter.

The following table is a summary of stock option activity for the years ended December 31, 2006, 2005 and 2004:

	2006		2005		2004	
Stock Options	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price	Shares	Weighted-Average Exercise Price
Outstanding at Beginning of Year	913,348	$ 15.32	1,217,534	$ 15.22	2,024,252	$ 15.26
Granted	30,000	47.60	—	—	36,750	23.32
Exercised	(438,473)	14.39	(300,493)	14.92	(793,775)	15.69
Forfeited or Expired	(900)	18.20	(3,693)	14.85	(49,693)	14.25
Outstanding at December 31(1)	**503,975**	**$ 18.05**	913,348	$ 15.32	1,217,534	$ 15.22
Options Exercisable at December 31(2)	**473,975**	**$ 16.18**	895,848	$ 15.30	565,994	$ 15.18

(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, 2006 was $21.5 million. The weighted-average remaining contractual term is 1.3 years.

(2) The aggregate intrinsic value of options exercisable at December 31, 2006 was $21.1 million. The weighted-average remaining contractual term is 1.1 years.

The total intrinsic value of options exercised during the years ended December 31, 2006, 2005 and 2004 was $17.7 million, $6.9 million and $5.8 million, respectively.

At December 31, 2006, the exercise price range for outstanding options was $12.84 to $47.60 per share. The following tables provide more information about the options by exercise price.

Options with exercise prices between $12.84 and $15.00 per share:

Options Outstanding	
Number of Options	7,350
Weighted Average Exercise Price	$ 12.84
Weighted Average Contractual Term *(In years)*	0.1

Options Exercisable	
Number of Options	7,350
Weighted Average Exercise Price	$ 12.84
Weighted Average Contractual Term *(In years)*	0.1

Options with exercise prices between $15.01 and $30.00 per share:

Options Outstanding	
Number of Options	466,625
Weighted Average Exercise Price	$ 16.23
Weighted Average Contractual Term *(In years)*	1.1

Options Exercisable	
Number of Options	466,625
Weighted Average Exercise Price	$ 16.23
Weighted Average Contractual Term *(In years)*	1.1

Options with exercise prices between $30.01 and $47.60 per share:

Options Outstanding	
Number of Options	30,000
Weighted Average Exercise Price	$ 47.60
Weighted Average Contractual Term *(In years)*	4.2

None of the options with exercise prices between $30.01 and $47.60 were exercisable as of December 31, 2006.

Stock Appreciation Rights

On February 23, 2006, the Compensation Committee granted 132,800 SARs to employees. These awards allow the employee to receive any intrinsic value over the $47.60 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 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 of December 31, 2006, there were 132,800 SARs outstanding and none were excercisable. The aggregate intrinsic value of these awards was $1.7 million at December 31, 2006. 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, 2006
Weighted-Average Value per Option Granted During the Period (1)	**$ 14.19**
Assumptions	
Stock Price Volatility	**31.6%**
Risk Free Rate of Return	**4.6%**
Expected Dividend	**0.3%**
Expected Term *(In years)*	**3.75**

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

Compensation expense recorded during the year ended December 31, 2006 for these SARs was $1.0 million. As no SARs were outstanding during 2005 and 2004, no compensation expense was recorded for this type of award. In addition, all SARs were unvested at December 31, 2006. Unamortized expense as of December 31, 2006 for all outstanding SARs was $0.9 million which will be recognized over the next 2.2 years.

Performance Share Awards

During 2006, the Compensation Committee granted two types of performance share awards to employees for a total of 142,750 performance shares. The performance period for both of these awards commenced January 1, 2006 and ends December 31, 2008. Certain of these awards, totaling 52,900 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 vesting performance period. Depending on the Company's performance, employees may earn up to 100% of the award in common stock, and an additional 100% of the award in cash. A new type of award was granted to non-executive employees in 2006, for a total of 89,850 shares, which measures the Company's performance based on internal metrics rather than a peer group. 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 three performance criteria set by the Company's Compensation Committee. An employee will earn one-third of the award granted for each internal metric performance criteria 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, 2006, it is currently considered probable that these three criteria will be met.

Both of these types of awards vest at the end of a designated three year performance period. For all awards granted to employees before and after January 1, 2006, an annual forfeiture rate ranging from 0% to 5.0% was assumed based on the Company's history for this type of award to various employee groups.

On December 31, 2006, the performance period ended for the performance shares awarded in 2004, which were based on total shareholder return. Due to the ranking of the Company compared to its peers in its predetermined peer group, 100% of the award, valued at $4.8 million based on the average of the high and low stock price on the grant date, is payable in 225,000 shares of common stock. An additional 33 percent, equal to one-third of the total value of the award, calculated by using the high and low stock price on December 29, 2006 multiplied by the number of performance shares earned, or $4.6 million, is payable in cash. These amounts were paid in January 2007. The calculation of the award payout was approved by the Compensation Committee on January 4, 2007, and the vesting of these shares will be reported in the first quarter of 2007.

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 was 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 were bifurcated. On the grant date, the equity component was valued using a Monte Carlo binomial model and is being amortized on a straight-line basis over the vesting period of three years. The liability component was 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 stock price movement. The risk-free rate was generated from the Federal Reserve website for constant maturity treasuries for six-month and 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. A sample of correlation statistics were reviewed between the Company and its peers and the average ranged between 87% and 93%.

The following assumptions were used as of December 31, 2006 for the Monte Carlo model to value the liability components of the peer group measured performance share awards. The equity portion of the award granted in 2006 was valued on the date of grant using the Monte Carlo model and this portion was not marked to market.

	Asof December 31, 2006
Risk Free Rate of Return	4.8% - 4.9%
Stock Price Volatility	32.6%
Correlation in stock price movement	90%
Expected dividend	0.3%

The Monte Carlo value per share for the liability for performance share awards at December 31, 2006 ranged from $20.26 to $52.36. The long-term liability, included in Other Liabilities in the Consolidated Balance Sheet, and short-term liability, included in Accrued Liabilities in the Consolidated Balance Sheet, for performance share awards at December 31, 2006 was $3.9 million and $4.6 million, respectively.

The following table is a summary of performance share award activity for the year ended December 31, 2006:

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, 2005	346,150	$ 24.34		
Granted	142,750	42.13		
Vested[3]	(15,300)	25.17		
Forfeited	(3,550)	33.26		
Non-vested shares outstanding at December 31, 2006	**470,050**	**$ 29.65**	**1.7**	**$ 28,509**

(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, 2006 by the number of non-vested performance share awards outstanding.

(3) These shares vested as a result of the death of one of the Company's officers.

During the year ended December 31, 2005, 110,200 performance share awards were granted with a grant date fair value per share of $30.43. During the year ended December 31, 2004, 252,750 performance share awards were granted with a grant date fair value per share of $21.49. No performance shares vested in 2005 or 2004. During 2005 and 2004, 8,700 and 8,100 performance shares, respectively, were forfeited.

Total unamortized compensation cost related to the equity component of performance shares at December 31, 2006 was $5.1 million and will be recognized over the next 1.7 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, 2006, 2005 and 2004 was $12.9 million, $3.3 million and $3.2 million, respectively.

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 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 the Company's financial position, results of operations or cash flows.

Long-Term Debt

	December 31, 2006		December 31, 2005	
(In thousands)	**Carrying Amount**	**Estimated Fair Value**	Carrying Amount	Estimated Fair Value
Long-Term Debt				
7.19% Notes	**$ 60,000**	**$ 61,749**	$ 80,000	$ 83,295
7.26% Notes	**75,000**	**80,335**	75,000	81,713
7.36% Notes	**75,000**	**82,025**	75,000	83,990
7.46% Notes	**20,000**	**22,547**	20,000	23,083
Credit Facility	**10,000**	**10,000**	90,000	90,000
Current Maturities				
7.19% Notes	**(20,000)**	**(20,299)**	(20,000)	(20,357)
Long-Term Debt, excluding Current Maturities	**$ 220,000**	**$ 236,357**	$ 320,000	$ 341,724

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, 2006, the Company had 20 cash flow hedges open: 19 natural gas price collar arrangements and one crude oil collar arrangement. At December 31, 2006, an $82.0 million ($51.2 million, net of tax) unrealized gain was recorded in Accumulated Other Comprehensive Income, along with an $82.0 million short-term derivative receivable. 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 2006, there was no ineffectiveness recorded in the Consolidated Statement of Operations. For the years ended December 31, 2005 and 2004, a $6.6 million gain and a $2.0 million loss were recorded as components 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, 2006 the Company would expect to reclassify to the Consolidated Statement of Operations, over the next 12 months, $51.2 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, 2006 related to anticipated 2007 production.

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 2006, natural gas price collars covered 27,179 Mmcf of the Company's gas production, or 34% of gas production with a weighted average floor of $8.25 per Mcf and a weighted average ceiling of $12.74 per Mcf. During 2006, an oil price collar covered 365 Mbbl of the Company's crude oil production, or 26% of crude oil production with an average floor of $50.00 per Mbbl and an average ceiling of $76.00 per Mbbl.

At December 31, 2006, the Company had open natural gas price collar contracts covering its 2007 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, 2006			
First Quarter 2007	10,487	$ 12.19/$8.99	
Second Quarter 2007	10,604	12.19/8.99	
Third Quarter 2007	10,721	12.19/8.99	
Fourth Quarter 2007	10,721	12.19/8.99	
Full Year 2007	**42,533**	**$ 12.19/$8.99**	**$ 81,393**

At December 31, 2006, the Company had one open crude oil price collar contract covering its 2007 production as follows:

	Crude Oil Price Collar		
Contract Period	Volume in Mbbl	Average Ceiling/Floor *(per Bbl)*	Net Unrealized Gain *(In thousands)*
As of December 31, 2006			
First Quarter 2007	90	$ 80.00/$60.00	
Second Quarter 2007	91	80.00/60.00	
Third Quarter 2007	92	80.00/60.00	
Fourth Quarter 2007	92	80.00/60.00	
Full Year 2007	**365**	**$80.00/$60.00**	**$ 589**

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 2006, no customer accounted for more than 10% of the Company's total sales. In each of 2005 and 2004 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, 2006, 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, 2006 and 2005 was $1.4 million in each year and $1.7 million for the year ended December 31, 2004, 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, 2005	$ 42,991
Liabilities added during the current period	2,089
Liabilities settled and divested during the current period	(23,775)
Current period accretion expense	1,350
Carrying amount of asset retirement obligations at December 31, 2006	**$ 22,655**

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 using the treasury stock method except that the denominator is increased to reflect the potential dilution that could occur if stock options and stock awards outstanding at the end of the applicable period were exercised.

The following is a calculation of basic and diluted weighted average shares outstanding for the years ended December 31, 2006, 2005 and 2004:

	December 31,		
(In thousands)	**2006**	2005	2004
Shares - basic	**48,401,642**	48,856,491	48,732,504
Dilution effect of stock options and awards at end of period	**898,850**	868,904	606,297
Shares - diluted	**49,300,492**	49,725,395	49,338,801
Stock awards and shares excluded from diluted earnings per share due to the anti-dilutive effect	**—**	—	—

14. Accumulated Other Comprehensive Income

Changes in the components of accumulated other comprehensive income, net of taxes, for the years ended December 31, 2006, 2005 and 2004 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, 2003	$ (20,957)	$ (2,173)	$ (5)	$ (23,135)
Net change in unrealized gains on cash flow hedges, net of taxes of ($1,908)	3,114	—	—	3,114
Net change in minimum pension liability, net of taxes of $535	—	(869)	—	(869)
Change in foreign currency translation adjustment, net of taxes of ($123)	—	—	539	539
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**

15. Subsequent Event-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 will be distributed on March 30, 2007 to shareholders of record on March 16, 2007. The pro forma effect on the December 31, 2006 balance sheet is to reduce Additional Paid-in-Capital by $5.1 million and increase Common Stock by $5.1 million. Common shares outstanding, giving retroactive effect to the stock split at December 31, 2006 and 2005, would have been 96.2 million and 97.1 million, respectively. Weighted-average common shares outstanding, giving retroactive effect to the stock split at December 31, 2006, 2005 and 2004, would have been 96.8 million, 97.7 million and 97.5 million, respectively. Pro forma earnings per share, giving retroactive effect to the stock split are as follows:

	December 31,		
	2006	2005	2004
Basic Earnings per Share - as reported (pre-stock split)	**$ 6.64**	$ 3.04	$ 1.81
Basic Earnings per Share - pro forma (post-stock split)	**3.32**	1.52	0.91
Diluted Earnings per Share - as reported (pre-stock split)	**6.51**	2.99	1.79
Diluted Earnings per Share - pro forma (post-stock split)	**3.26**	1.49	0.90

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, 2006, 2005, and 2004 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, 2007, 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, 2006, 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)	**2006**	2005	2004
Proved Reserves			
Beginning of Year	**1,262,096**	1,134,081	1,069,484
Revisions of Prior Estimates	**(17,675)**	(1,543)	(7,850)
Extensions, Discoveries and Other Additions	**246,197**	185,884	140,986
Production	**(79,722)**	(73,879)	(72,833)
Purchases of Reserves in Place	**1,946**	17,567	5,384
Sales of Reserves in Place	**(44,549)**	(14)	(1,090)
End of Year	**1,368,293**	1,262,096	1,134,081
Proved Developed Reserves	**996,850**	944,897	857,834
Percentage of Reserves Developed	**72.9%**	74.9%	75.6%

(Thousands of barrels)	Liquids December 31, 2006	2005	2004
Proved Reserves			
Beginning of Year	**11,463**	11,384	12,103
Revisions of Prior Estimates	**673**	1,073	185
Extensions, Discoveries and Other Additions	**1,066**	334	1,074
Production	**(1,415)**	(1,747)	(2,002)
Purchases of Reserves in Place	**38**	419	24
Sales of Reserves in Place	**(3,852)**	—	—
End of Year	**7,973**	11,463	11,384
Proved Developed Reserves	**5,895**	9,127	8,652
Percentage of Reserves Developed	**73.9%**	79.6%	76.0%

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.

(In thousands)	December 31, 2006	2005	2004
Aggregate Capitalized Costs Relating to Oil and Gas Producing Activities	**$ 2,462,693**	$ 2,290,147	$ 1,933,848
Aggregate Accumulated Depreciation, Depletion and Amortization	**983,079**	1,052,654	940,447

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

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

(In thousands)	Year Ended December 31, 2006	2005	2004
Property Acquisition Costs, Proved	**$ 6,688**	$ 73,127	$ 3,953
Property Acquisition Costs, Unproved	**42,551**	22,126	18,250
Exploration and Extension Well Costs (1)	**109,525**	102,957	85,415
Development Costs	**346,787**	208,124	136,311
Total Costs	**$ 505,551**	$ 406,334	$ 243,929

(1) Includes administrative exploration costs of $13,486, $12,423 and $11,354 for the years ended December 31, 2006, 2005, and 2004, 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)	**2006**	2005	2004
Operating Revenues	**$ 659,884**	$ 581,849	$ 439,988
Costs and Expenses			
Production	**115,786**	103,477	84,015
Other Operating	**46,212**	30,120	27,787
Exploration (1)	**49,397**	61,840	48,130
Depreciation, Depletion and Amortization	**139,207**	119,122	114,906
Total Costs and Expenses	**350,602**	314,559	274,838
Income Before Income Taxes	**309,282**	267,290	165,150
Provision for Income Taxes	**113,355**	100,353	60,361
Results of Operations	**$ 195,927**	$ 166,937	$ 104,789

(1) Includes administrative exploration costs of $13,486, $12,423 and $11,354 for the years ended December 31, 2006, 2005, and 2004, 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, 2006, 2005, and 2004 for natural gas ($ per Mcf) were $5.54, $9.53 and $6.26, respectively, and for oil ($ per Bbl) were $59.50, $58.48 and $41.24, 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, 2006	2005	2004
Future Cash Inflows	**$ 8,054,737**	$ 12,700,390	$ 7,561,728
Future Production Costs	**(2,000,993)**	(2,271,917)	(1,577,787)
Future Development Costs	**(688,955)**	(536,333)	(396,431)
Future Income Tax Expenses	**(1,763,458)**	(3,588,877)	(2,009,644)
Future Net Cash Flows	**3,601,331**	6,303,263	3,577,866
10% Annual Discount for Estimated Timing of Cash Flows	**(2,125,081)**	(3,652,030)	(1,997,509)
Standardized Measure of Discounted Future Net Cash Flows (1)	**$ 1,476,250**	$ 2,651,233	$ 1,580,357

(1) The standardized measures of discounted future net cash flows before taxes were $2,010,228, $4,001,769 and $2,358,430 for the years ended December 31, 2006, 2005 and 2004, 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, 2006	2005	2004
Beginning of Year	**$ 2,651,233**	$ 1,580,357	$ 1,479,408
Discoveries and Extensions, Net of Related Future Costs	**278,258**	494,773	321,026
Net Changes in Prices and Production Costs	**(1,843,272)**	1,278,303	(17,976)
Accretion of Discount	**400,177**	235,843	219,604
Revisions of Previous Quantity Estimates,Timing and Other	**(106,253)**	(49,550)	(46,115)
Development Costs Incurred	**85,993**	61,802	32,940
Sales and Transfers, Net of Production Costs	**(544,650)**	(471,638)	(357,939)
Net Purchases (Sales) of Reserves in Place	**(261,795)**	91,180	10,853
Net Change in Income Taxes	**816,559**	(569,837)	(61,444)
End of Year	**$ 1,476,250**	$ 2,651,233	$ 1,580,357

SELECTED DATA (UNAUDITED)

QUARTERLY FINANCIAL INFORMATION (UNAUDITED)

(In thousands, except per share amounts)	First	Second	Third	Fourth	Total
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	**1.09**	**0.96**	**3.92**	**0.67**	**6.64**
Diluted Earnings per Share	**1.08**	**0.94**	**3.84**	**0.66**	**6.51**
2005					
Operating Revenues	$ 144,074	$ 151,884	$ 161,757	$ 225,082	$ 682,797
Impairment of Oil and Gas Properties (1)	—	—	—	—	—
Operating Income	38,044	61,722	59,023	99,942	258,731
Net Income	20,762	35,422	33,756	58,505	148,445
Basic Earnings per Share	0.43	0.72	0.69	1.20	3.04
Diluted Earnings per Share	0.42	0.71	0.68	1.18	2.99

(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 contain the gain on the disposition of offshore and certain south Louisiana properties of $229.7 million and $1.5 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.

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, 2006, 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 issuer 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, 2006. 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, 2006, the Company's internal control over financial reporting is effective based on those criteria.

Cabot Oil & Gas Corporation's independent registered public accounting firm has audited management's assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2006 as stated in their report entitled "Report of Independent Registered Public Accounting Firm" 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 2007 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 2007 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 2007 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 2007 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 2007 annual stockholders' meeting.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

A. INDEX

1. Consolidated Financial Statements

See Index on page 66.

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 September 6, 2001 (Form 10-K for 2001).
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).
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).
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).

Exhibit Number	Description
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.
*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. (a) Form of Restricted Stock Award Agreement. (b) Form of Stock Appreciation Rights Award Agreement. (c) Form of Performance Share Award Agreement.
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.
*10.23	Pension Plan of the Company, as amended and restated 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).
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 28th of February 2007.

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 28, 2007
/s/ Scott C. Schroeder Scott C. Schroeder	Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2007
/s/ Henry C. Smyth Henry C. Smyth	Vice President, Controller and Treasurer (Principal Accounting Officer)	February 28, 2007
/s/ John G. L. Cabot John G. L. Cabot	Director	February 28, 2007
/s/ David M. Carmichael David M. Carmichael	Director	February 28, 2007
/s/ James G. Floyd James G. Floyd	Director	February 28, 2007
/s/ Robert L. Keiser Robert L. Keiser	Director	February 28, 2007
/s/ Robert Kelley Robert Kelley	Director	February 28, 2007
/s/ P. Dexter Peacock P. Dexter Peacock	Director	February 28, 2007
/s/ William P. Vititoe William P. Vititoe	Director	February 28, 2007

Corporate Information

Officers

Dan O. Dinges
Chairman, President and Chief Executive Officer

Michael B. Walen
Senior Vice President and 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, Eastern 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, May 2, 2007, at 8:00 a.m. (CDT) at the corporate office in Houston, Texas.

Corporate Office

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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

The Bank of New York Shareholder Relations Department
P. O. Box 11258
Church Street Station
New York, New York 10286
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(610) 382-7833 (Outside the U.S.)
(888) 269-5221 (Hearing Impaired – TDD Phone)
shareowner@bankofny.com
www.stockbny.com

Send Certificates for Transfer and Address Changes to:

Receive and Deliver Department
P. O. Box 11002
Church Street Station
New York, New York 10286

Corporate Governance Matters

On May 30, 2006, 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 2006 quarterly reports on Form 10-Q and the 2006 annual report on Form 10-K as mandated by the Sarbanes-Oxley Act of 2002.

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Cabot Oil & Gas Corporation

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